Northwest Power and Conservation Council

August 30, 2007

MEMORANDUM

TO: Power Committee

FROM: Terry Morlan

SUBJECT: Briefing on Residential Exchange and Average System Cost Methodology

Bonneville, its customers, and other interested parties are meeting several times a week to resolve the many details required to implement the Regional Dialogue Policy. We are setting up a standard item on the Power Committee agenda for the next several months to report on the progress of these discussions. Bill Hannaford, Leann Bleakney, and Howard Schwartz are covering these meetings and will prepare weekly reports on their progress.

For the September meeting, we have asked Terry Mundorf, who represents the Washington Public Agency Group in the Regional Dialogue process, to give the Power Committee some basic background on issues related to the residential exchange program. Terry probably understands the issues around the residential exchange, average system cost, and 7(b)(2) provisions as well as, perhaps better than, anyone in the region. He has not been asked to give the public agency perspective on these issues, but to give you a primer. Terry is very articulate and will be able to address any questions that you have.

A memorandum from Bill Hannaford and Leann Bleakney summarizing discussion to date on residential exchange issues is attached. In addition, a Bonneville fact sheet on the residential exchange program is attached as further information.

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Northwest Power and Conservation Council

August 27, 2007

MEMORANDUM

TO: Council Members, Power Planning Division, State Power Staff, Division Directors, and John Harrison

FROM: Bill Hannaford and Leann Bleakney

SUBJECT: Regional Dialogue Workshops

The topic of the Regional Dialogue workshops last week was the Residential Exchange Program (REP) and its various components. The first workshop covered the 7(b)(2) rate test and its attendant issues. The next covered the historical structure and operation of the REP, including the Northwest Power Act, Bonneville's 1981 and 1984 Methodologies, the chronology of an average system cost (ASC) determination, and the multitude of REP and ASC calculation issues. The final session focused on the particulars of the ASC determination and laid out the range of future ASC methodology options.

Bonneville intends to publish an initial proposal revising the ASC Methodology in the Federal Register in December of this year. After the public comment process, the agency expects to complete the methodology by July, 2008. Bonneville staff has not yet given much consideration to the question of how the agency intends to meet the requirement in the Northwest Power Act that the agency consult with the Council in developing the ASC methodology. It is worth noting that the Council did not, in fact, consult in the development of the original or the revised methodologies.

The Act created the REP to address access to the benefits of the Federal Columbia River Power System for the publics, IOUs, and DSIs. The publics retain preference to Bonneville power for their net requirements and both publics and IOUs may receive exchange benefits. The publics' exposure to higher costs is limited by the 7(b)(2) rate test, which is designed to ensure that the cost of the REP and other factors do not raise the rates of the publics beyond what they otherwise would have been, taking into account five factors. Exchange benefits are calculated according to the following formula: Benefits = the utility's ASC - Bonneville PF Exchange Rate X the utility's exchange load.

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Section 7(b)(2) includes five assumptions Bonneville is to observe in setting preference rates. These assumptions envision a world that contrasts with the world under the Northwest Power Act. In other words, Bonneville must assume that in this hypothetical world:

1. Bonneville is not engaging in an exchange of power with IOUs and consumer-owned utilities to provide rate relief to those utilities' residential and small farm customers.

2. Bonneville's public utility customers would serve certain of the direct-service industries with 100 percent firm power.

3. The preference customers' load, including the DSI loads mentioned in the second assumption, would be served first with Federal Base System power.

4. If the preference customers require more power to serve their loads than federal resources can supply, the additional power to meet these needs would be acquired from certain specified sources. This additional power would be provided in a least cost-first manner.

5. There are no dollar savings to the preference customers as a result of reduced financing costs due to Bonneville backing of resource acquisitions, and no reserve benefits due to Bonneville's actions under the Act accrue to them.

While calculation of a utility's ASC may seem to require only the simple application of the formula set out in the Act, in reality, each component of the formula is subject to interpretation and challenge, as we learned over the course of the two days last week. For example, is the "DSI load" today's load, the service the DSIs would like to take or the load that existed when the Northwest Power Act was written? Bonneville has one interpretation, customers have another. Are there, again, other factors than the five outlined in the Act? Yes, Bonneville admitted, the agency also considers the added elasticity to the system that result from the working of the exchange. Customers challenged Bonneville to identify the statutory basis for taking elasticity into account. The treatment of conservation and the accounting for embedded conservation in calculating a utility's load was warmly debated.

Bonneville hasn't updated the ASC methodology since 1984, so that up to the time of the settlement agreements, it continued to use that same methodology. If Bonneville and the utilities are not able to reach an agreement for the components of a new ASC methodology, the 1984 methodology will be used. Many of the elements of this calculation were discussed, including whether to include forecasts of future years with inflationary factors already determined. The 1984 ASC methodology does not use forecasted costs.

Bonneville went to great lengths to demonstrate how costly and time-consuming the operation of the REP was historically. As noted above, every aspect of the program appears to be subject to conflicting interpretations. Over time, a number of determinations and policy interpretations have been taken to the Ninth Circuit. This lengthy discussion seems aimed at encouraging the participants to think creatively about a new and simplified approach to how to proceed with the REP in the future and Bonneville laid out a number of ways of determining a utility's ASC in the future. A future workshop will encourage participants to express their preferences.

Bonneville will have a number of proceedings underway at the same time over the coming year.

In February, 2008, Bonneville will open a 7(i) rate-case proceeding to develop the tiered rates methodology. Tiered rates will be implemented in 2012.

In December, 2007, Bonneville will open a 7(i) rate-case proceeding identified as WP09, which will be a general power case, the 7(b)(2) determination, plus the remand issues. The ASC consultation proceeding will also begin in December.

In February, 2008, Bonneville will open a 7(i) rate proceeding called the wind integration rate case that will take be a joint case between power and transmission.

factsheet

June 2007

A history of BPA's Residential Exchange Program

On May 3, 2007, the U.S. Ninth Circuit Court of Appeals ruled on two lawsuits that have significant implications for the Bonneville Power Administration's Residential Exchange Program (REP). In light of the Court's decision and the heightened interest it has created over the REP, BPA has prepared this history and background of the REP.

The REP was established in Section 5(c) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (known commonly as the Northwest Power Act). The goal of the program has been to provide rate relief to Northwest residential and small-farm customers served by high-cost investor-owned utilities, as well as to residential and small-farm customers served by high-cost utilities with preference rights. At the same time, Congress intended to limit the financial exposure of public utilities to certain costs occurring under the Northwest Power Act.

In crafting Section (5), Congress directed that the benefits of the Federal Columbia River Power System (FCRPS) would be shared with those Northwest utilities whose average system cost or ASC (average cost of resources) was high relative to BPA's applicable Priority Firm Exchange rate. The benefits BPA provides through the program must be passed on to each utility's residential and small-farm customers and cannot be used for any other purpose, such as profits or to subsidize other aspects of a utility's business.

From its start, the Residential Exchange Program (REP) has been a source of nearly continuous controversy. Its roots go back to the 1970s when electricity rates between public and private utilities began to diverge sharply. Public preference was at the heart of the debate between public and private interests.

Historically, private and public utility rates had been comparable. This changed after 1973 when, faced with likely energy shortages, BPA halted firm power sales to the region's investor-owned utilities. The rates of some IOUs then began to rise sharply.

Oregon drafts DRPA legislation

At that point, Oregon's Public Utility Commissioner awarded a 90-day contract "to find a legal way to overturn ... the preference clause,[1] thus qualifying Oregon's private utility customers for the same electricity rates that public power customers enjoy." When it appeared preference could not be overturned legally, the state turned to an innovative solution.

In 1977, the Oregon state legislature approved forming the entire state into a Domestic and Rural Power Authority (DRPA), which was to lay claim as a publicly owned utility to federal hydropower to benefit all of the state's citizens. DRPA was to become effective March 1, 1979, if no federal energy bill addressing the problem had been passed. The deadline later elapsed because, by that time, it appeared national legislation was imminent.

[1] Section 4 of the Bonneville Project Act of 1937 grants public bodies and cooperatives priority access to federal power. This is known as the preference clause.

In 1977, the Pacific Northwest Utilities Conference Committee (PNUCC), which includes both public and private utilities, presented draft legislation "for discussion purposes" to the region's congressional delegation to address multiple issues precipitated by growing concern about power shortages. Fearing their right to first call on federal power would be curbed, Snohomish PUD and Seattle City Light broke ranks and opposed the draft. Snohomish introduced rival legislation aimed at protecting public preference.

Public preference challenged

As various proposals emerged, the fight over preference heated up. Washington Governor Dixie Lee Ray dubbed it "a regional civil war."

Idaho threatened to follow Oregon's lead to create a domestic and rural power authority. The executive director of the Washington Public Utility District Association declared DRPA "nothing but a façade to protect the profits of private power companies serving his [Oregon governor's] state."

In February 1978, the governors of Oregon and Idaho declared BPA "must honor the commitments in acts of Congress that domestic and rural customers have first call on energy from the Federal dams that are even more basic than those of what BPA calls preference customers."

BPA Administrator Sterling Munro strongly defended preference. His view was that the way to get cheap federal power to the three "have-not"[2] states was to increase the size of the resource pie, rather than do away with preference. Oregon Congressman Robert Duncan responded, "If the preference clause isn't changed, then we'll bust the sonofabitch in a lawsuit. The people of the Northwest, all of the people of the Northwest, are entitled to similar energy rates, and they should share the burden of those costs."

By the late 1970s, a number of proposals were coalescing into what eventually would culminate in the Northwest Power Act. Any legislation would have to pass through the Senate Energy and Natural Resources Committee, headed by Senator Henry "Scoop" Jackson. Jackson, who was from Washington state, was an advocate of public power and not overly sympathetic to the public-private power rate disparity arguments. Eventually, however, he realized that, if the legislation was to have any chance, it had to deal with the issue. Otherwise, the principle of preference would be at risk.

DSI "subsidy" paves way for exchange

A breakthrough came when the direct-service industries, facing expiration of their contracts, agreed to pay significantly higher rates for a limited period in return for new 20-year contracts. At the time "assured supply" was more important to them than price. Under this arrangement, public power would continue to get first call on federal power, but a "subsidy" from the DSIs (the higher rates the industries were willing to pay) would offset and lower IOU rates. This "money deal," which only covered five years, paved the way for an "exchange clause" in the new legislation.

The exchange provision allowed BPA to offer IOUs and certain public power entities that owned higher-cost generating facilities a quantity of power at BPA's standard rates equivalent to the total needs of those utilities' residential and small-farm customers. In exchange, BPA would accept from these utilities an equal quantity of power at their average system costs. No power needed to change hands; in reality, it was primarily a monetary paper transaction. Under the exchange, the utilities were required to pass on the benefits to their residential and small-farm customers in the form of lower rates.

Section 7(c)(1) of the Act addressed the DSI provision saying that DSI rates shall be established for the period prior to July 1, 1985, at a level sufficient to recover the costs of resources required to serve the DSIs' loads and "the net costs incurred by the Administrator pursuant to Section 5(c) of this Act." Section 5(c)(1) stipulates the exchange of power with eligible utilities requesting such an exchange.

[2] The "have-not states" refers to Oregon, Idaho and western Montana, which, unlike Washington, are served primarily by investor-owned utilities that do not have preference to BPA power.

Not all the DSIs were happy with the arrangement. In August 1978, Reynolds Metals objected, saying the draft bill language placed too much of the burden of exchange costs on the DSIs. At the time, the aluminum industry had a great deal of leverage as it was providing enormous benefits to the region in terms of wages, freight services and state and local taxes. The industry had provided about 30 percent of BPA's revenues.

NW Power Act changes regional landscape

After several stops and starts, the Northwest Power Act finally emerged and was signed into law in December 1980. The Act's exchange provision extended benefits of the federal system "at cost" to 2.5 million residential and small-farm consumers of IOUs and a handful of consumer-owned utilities that had relatively high ASCs.

To win public power support while the Northwest Power Act was being developed, or at least to counter opposition, an amendment had been added in the form of a rate test to provide some cost protection to the preference customers' rates. This is the 7(b)(2) test, which compares costs developed pursuant to the Act with costs reflecting five specified assumptions listed in Section 7(b)(2). In very general terms, it was designed to ensure public customers would pay BPA no more than if their rates had been developed based on the five assumptions.

BPA is required to formulate a hypothetical case to assess what costs would have been by using the five assumptions in Section 7(b)(2). If the rate test shows preference customers would have to pay more for firm power under actual rates than under the hypothetical case, the Administrator must lower the rates of public utilities to eliminate the excess costs and shift the burden to BPA's other customers. The Act contains five assumptions under Section 7(b)(2) to be used in determining what the hypothetical world would look like.

The language in Section 7(b)(2) is complex and has been subject to differing interpretations. Former BPA Administrator Peter Johnson said of this section, " ... I know how Alice felt when she stepped through the mirror. We seem to have entered an unreal world. The assumptions direct BPA to hypothesize power supply arrangements between itself and its customers – arrangements that are quite different from reality. The Act bounces us back and forth between what might have been had the Act not been passed and what is."

The 7(b)(2) rate test

The Northwest Power Act provides, through Section 7(b)(2), a complex formula (rate test) that, in general terms, shields preference customers from certain impacts of the Northwest Power Act. Basically, this rate test is designed to ensure that the cost of the Residential Exchange Program and other factors, when considered together, do not raise the rates of public utilities beyond what they would have been absent the Northwest Power Act.

Section 7(b)(2) includes five assumptions the Administrator uses to develop a set of costs that is compared with a set of costs reflecting the Northwest Power Act. This comparison is used in setting preference rates. (See box on five assumptions.)

If Section 7(b)(2) "triggers," then an amount of costs is allocated to rates other than the PF (Priority Firm) power rate, which is the rate that applies to preference customers' requirements loads.

Consequently, BPA develops a PF Exchange rate for REP loads that includes costs from any Section 7(b)(2) trigger amount. If there is a trigger, the PF Exchange rate is higher than the PF Preference rate, and the difference between the PF Exchange rate and the utility's ASC, multiplied by the utility's residential and small-farm load, determines the REP benefits for a qualifying utility.

The five assumptions

Section 7(b)(2) includes five assumptions the Administrator is to observe in setting preference rates. These assumptions envision a world that contrasts with the world under the Northwest Power Act. In other words, the Administrator must assume that in this hypothetical world:

1. BPA is not engaging in an exchange of power with IOUs and consumer-owned utilities to provide rate relief to those utilities' residential and small-farm customers.

2. BPA's public utility customers would serve certain of the direct-service industries with 100 percent firm power. The industries that would be served by the public utilities are (a) those industries served by BPA and (b) those that are situated within or adjacent to the service territories of the public customers.

3. The preference customers' load, including the DSI loads mentioned in the second assumption, would be served first with Federal Base System power.

4. If the preference customers require more power to serve their loads than federal resources can supply, the additional power to meet these needs would be acquired from certain specified sources. This additional power would be provided in a least-cost-first manner.

5. There are no dollar savings to the preference customers as a result of reduced financing costs due to BPA backing of resource acquisitions, and no reserve benefits due to the Administrator's actions under the Act accrue to them.

In 1983, BPA sought to clarify Section 7(b)(2) and, after an initial round of comments, published a "Notice of Proposed Legal Interpretation of Section 7(b)(2)." After adopting the legal interpretation, BPA developed a Section 7(b)(2) Implementation Methodology. BPA published the Implementation Methodology, which reflected its legal interpretation of 7(b)(2), in the Federal Register in March 1984. Subsequently, BPA developed computer models,[3] in consultation with customers, for the rate test.

The 7(b)(2) rate test has triggered several times. In BPA's 1996 and 2002 power rate cases, the upward pressure on the PF Exchange rate was significantly more than in previous years. In the WP-96 and WP-02 rate cases, due to high 7(b)(2) triggers, the PF Exchange rate was 8.3 mills per kilowatt-hour and 13.7 mills per kilowatt-hour higher, respectively, than the PF Preference rates.

ASC Methodology established

BPA established its initial Average System Cost Methodology in 1981, issuing a Record of Decision on Aug. 26 of that year and filing the methodology with the Federal Energy Regulatory Commission the following day. FERC granted interim approval effective Oct. 1, 1981, and final approval of the ASC Methodology on Oct. 6, 1983 (retroactive to 1981). At its inception, the REP was implemented through Residential Purchase and Sale Agreements (RPSA) first executed in 1981. These contracts established exchange benefits only through July 1, 2001. Between 1981 and BPA's Subscription Strategy proposal, all of the RPSAs held by the utilities that had received REP benefits had been settled, except for one, which was in "deemer" status.[4]

BPA's 1981 RPSAs did not require a customer to own generation or transmission facilities to qualify for an RPSA. Utilities were able to include wholesale purchase power expenses and wheeling contracts with third parties as costs to establish an ASC. Distribution costs were excluded from the ASC calculation.

[3] BPA used a computer-based model known as the Supply Pricing Model (SPM). The model simulated the rate-setting process.

[4] BPA's 1981 RPSAs included a provision described as a deemer account. Deemer referred to a status wherein a utility sets its ASC equal to BPA's PF Exchange rate and does not receive positive monetary benefits but accrues a negative balance that must be worked off before resuming receipt of additional monetary benefits.

Average System Cost

An ASC represents the average cost of resources for any given utility. An ASC cannot, by law, include additional resource costs to serve new large single loads or extra-regional load or the costs of a resource terminated prior to commercial operation. The calculation includes a number of details, but generally, power costs and certain transmission costs are currently included in the ASC, although distribution costs are excluded. Customers with market purchases or those who own their own generation are most likely to have ASCs that are higher than BPA's PF Exchange rate. Since many of the Northwest's investor-owned utilities own coal or gas-fired plants, historically they have had higher ASCs than BPA's PF Exchange rate.

BPA's 1981 RPSAs included a number of contractual terms and conditions describing BPA's right to purchase power in lieu[5] of the utility's resources priced at its ASC. These reflected the electric power industry of the period and assumed that a utility would be developing its own resources or entering long-term purchase power contracts to serve its loads.

BPA revises ASC Methodology

From the start, things did not go smoothly. The DSIs, who were bearing the cost of the exchange through 1985, complained that the IOUs were including inappropriate costs and overhead in their average system costs. In 1983, Northwest Aluminum News wrote, "The main problem – and a monumental one – is that some participating utilities are using the exchange to recover costs other than 'resource' costs ... Some of the questionable costs include items such as taxes, overhead, and expenses related to uncompleted or discontinued power plant projects."

The IOUs denied the costs were improper. At the same time, public utilities that weren't participating in the exchange complained that attempts to include inappropriate costs in the ASC calculation were driving up the costs of power they were buying from BPA.

Beginning in 1983, the DSIs and public agency customers sought a change in the ASC Methodology. They had a number of concerns, including perceived abuses to the system related to the attempted inclusion of terminated plant costs. BPA had previously removed terminated plant costs from an ASC filing made by an exchanging utility.

BPA Administrator Peter Johnson agreed that the exchange was "not working as Congress intended." A BPA issue alert described the existing methodology as "unworkable, expensive, time consuming, and difficult to administer." Consequently, BPA staff recommended tighter procedures for computing the ASC.

Section 5(c) of the Northwest Power Act provides that the Administrator shall develop an ASC Methodology in consultation with the Northwest Power and Conservation Council, the Administrator's customers and appropriate state regulatory bodies. BPA initiated a consultation process open to the public to begin revising its ASC Methodology to address multiple issues.

These issues included the source data for the methodology, determination of whether transmission costs should be treated as resource costs, subsidization of construction work in progress, treatment of equity return, treatment of income taxes, determination of generating resources that could be included in computing ASC, treatment of affiliated fuel costs, includable conservation costs and functionalization between subsidized and nonsubsidized accounts. A Federal Register notice on the consultation process was issued in October 1983.

[5] In the context of the REP, "in lieu" comes up when the market price of power (or the price of other resources) is less than the exchanging utility's average system cost. In that case, the Northwest Power Act allows BPA to purchase power "in lieu" of exchanging at the utility's ASC. BPA would buy power at the market or resource rate and sell to the exchanging utility at the PF Exchange rate, thus reducing the level of benefits to the difference between the market price and PF Exchange rate. The utility would then have to find something else to do with the high-cost resources that have been "in lieued." Or, instead of being stuck with unwanted power, it could deem its ASC to be equal to the cost of the resource BPA would have acquired and sold to the utility. Either way, BPA saves on a unit basis the difference between the utility's ASC and the lower in-lieu resource cost.

After taking regional comment, BPA published a proposal on a revised ASC Methodology in February 1984 and, after a public comment period, issued a record of decision on its revised ASC Methodology in June 1984. In that year, nine IOUs and 16 public utilities were participating in the exchange.

IOUs challenge ASC revisions

Although the IOUs challenged the ASC Methodology change in the FERC proceeding, FERC approved the revised methodology. A number of IOUs challenged the change in the Ninth Circuit Court of Appeals, but the Court upheld BPA's decision *(PacifiCorp v. Fed. Energy Regulatory Comm'n, 759 F.2d 816 ((9th Cir. 1986))* in 1986. While the Court's opinion upheld the revised ASC Methodology, it held that it did not "sanction any permanent implementation of these exclusions." Id. at 823. Since then, the IOUs have argued that the Court upheld the 1984 ASC Methodology as a "temporary" change to address terminated plant cost issues and did not intend a permanent change.

The ASC Methodology provides for future changes. Under the ASC Methodology, the Administrator may initiate a consultation process to determine whether to change the existing ASC Methodology at his discretion or upon request from three-quarters of utilities with Residential Exchange contracts, three-quarters of BPA's preference customers or three-quarters of BPA's DSIs (which was relevant at the time).

Arguments continued into the 1990s as IOUs disputed BPA's calculation of the ASCs and other determinations related to the REP. Throughout the decade the disputes were essentially continuous. Key elements of the disputes included benefits under the RPSAs – not enough in the IOUs' opinions and too much according to the publics and DSIs – as well as BPA's ASC Methodology, utilities' ASCs, deemer balances, "in lieu" transactions and BPA's PF Exchange rate.

Region conducts Comprehensive Review

The advent of deregulation of the electric power industry in the 1990s changed the industry dramatically. Utilities no longer solely constructed generation or made long-term purchases. Increasingly, they purchased power on the wholesale market from independent producers, wholesale marketing entities and others, and some purchases were short-term. BPA began to face tough competitive challenges, and some questioned the agency's ability to fit into the newly deregulated world.

In the mid-1990s, the Department of Energy, BPA and the governors of the four Northwest states all called for a Comprehensive Review[6] of BPA's future role in the Northwest. One of the things that came out of the Comprehensive Review recommendations was a proposed Subscription process that would set parameters for allocating federal system benefits. This was precipitated by the fact that power sales contracts customers had signed with BPA were due to expire in 2001.

The Comprehensive Review, which published a final report in December 1996, took the opposite stance of an earlier BPA Administrator, Sterling Munro, who had said the way to spread the benefits of the federal system was to increase the size of the pie. Instead, the Comprehensive Review said BPA should get out of the business of acquiring new resources to meet customers' load growth, except in those cases where the customer would bear the additional costs.

The Comprehensive Review Steering Committee encouraged BPA and other parties in the region to explore a settlement of the REP with the region's IOUs based in part on a sale of power to them rather than the historic practice of monetary payments.

Congress helps stabilize exchange

By the mid-1990s, deregulation of the electric utility industry, spiraling fish costs brought by Endangered Species Act filings and reduced hydro supply had pushed BPA rates up. The most important factor, however, was the decrease in market price of power due largely to the entry of independent power producers selling gas-fired generation. As market prices

[6] The formal name of the review was the Comprehensive Review of Northwest Energy Systems.

dropped, some BPA customers removed load from BPA. For the first time, BPA's PF Exchange rate was higher than many of the utilities it was exchanging power with. As public power customers sought to exit contracts, concerns arose over whether BPA would have adequate customers to cover its costs.

In August 1995, BPA reported "The calculation 7(b)(2) required by the law has forced BPA to make the most significant reduction in Residential Exchange benefits in 11 years. The proposed reduction could cause up to 45 percent of the region's residential and small-farm customers to see an increase in rates." BPA cited increased competition, especially from natural gas, and said "... for the first time in its history, BPA has lost wholesale customers to private utilities."[7] At the time, BPA had been paying approximately $200 million a year to utilities participating in the REP.

BPA's Initial Proposal in its 1996 power rate case indicated a large reduction of benefits under the REP starting in fiscal year 1997. BPA was assuming REP benefits of about $65 million a year. Concern about reduced benefits prompted Congress to take action. The Energy and Water Development Appropriations Act of 1996 specified setting 1997 exchange benefits at the 1996 level of $145 million for the one-year period. BPA was to distribute the benefits to each participating utility at the percentage share each received in fiscal year 1995.[8]

In the 1996 Conference Report of the Energy and Water Development Appropriations Act, Congress recognized BPA's authority " ... to implement in lieu transactions, among other actions, which could effectively terminate the residential exchange after 2001." The report went on to say, "Consistent with the regional review, Bonneville and its customers should work together to gradually phase out the residential exchange program by October 1, 2001." BPA, however, could not eliminate implementing the REP without direct action by Congress to change the law.

In September 1997, BPA and the Northwest Power and Conservation Council jointly launched a review of BPA's costs. The purpose was to set the stage for a successful Subscription process by providing further cost-cutting recommendations to build customer confidence that BPA was doing all it could to contain costs. Among the recommendations, the Cost Review said the REP made no sense in the current marketplace and should be eliminated, although this could not be accomplished without legislative change.

In early summer 1996, Puget Sound Energy, Pacific Power and Portland General Electric expressed interest in a possible settlement of REP disputes. BPA entered negotiations with the three IOUs regarding a settlement of such disputes but deferred negotiations after failing to reach agreement on the total dollar settlement. Eventually, BPA settled with Puget in January 1997 and with Pacific in April of that year. BPA settled with PGE, then owned by Enron, a year later in April 1998. These agreements specified that they did not set precedents for how the Residential Exchange would be handled after 2001. Payments to the IOUs for the 1998-2001 period averaged $59 million annually.

As it turned out, 1996 was the last year that exchange benefits were determined through the traditional REP process (i.e., Appendix 1 filings, calculation of ASCs and PF Exchange rates). Congress set the level of exchange benefits for 1997. Following that, benefits were determined through the settlement agreements. Such settlements had been recommended by the Comprehensive Review and Congress. These settlements had the advantage of being far less labor intensive. Running the regular REP required about 50 BPA staff as well as significant numbers of staff from utilities.

[7] In February 1995, BPA listed four key pressures driving up its rates: 1) protracted drought; 2) increased salmon costs; 3) generation debt service due to the way refinancing for Washington Public Power Supply System bonds had been structured; and 4) additional generation costs due to short-term purchases and new generation projects including Tenaska, a gas-fired combustion turbine.

[8] Puget had a Periodic Rate Adjustment Mechanism (PRAM) to true up rates two years after the end of each rate period. In 1991, BPA and Puget formulated a "true-up" mechanism to permit an accurate determination of Puget's ASC benefits in conjunction with the Washington Utility and Transportation Commission's PRAM. PRAM true-up benefits were to be paid two years after the end of the exchange period.

2000 REP Settlements crafted

In the late 1990s, the market began to change as natural gas prices began to rise. BPA's Competitiveness Project, launched in 1993, was paying off in terms of improved financial performance and customer confidence. BPA's net revenues for 1997 were the best since 1991. In 1998, BPA launched a Subscription process generally consistent with recommendations from the Comprehensive Review. It was designed to culminate in new 10-year power sales contracts for the post-2001 period.

As part of the Subscription Strategy, BPA proposed to either continue the traditional REP through agreements known as Residential Purchase and Sale Agreements (RPSA) or enter into negotiated settlements of REP disputes for the FY 2002-2011 period. Such settlements were intended to provide benefits for the IOUs in return for their waiver of claims. In the settlements, the benefits reflected possible outcomes of ASC determinations and the effect of Section 7(b)(2) on BPA's PF Exchange rate.

Key issues can swing REP payments substantially

When BPA does a 7(b)(2) test, it must develop a hypothetical case to determine what the costs to preference customers would have been under the five 7(b)(2) assumptions. There are many arcane issues embedded in this calculation that have a significant impact on the potential level of REP payments.

One assumption (see five assumptions box) is that, if preference customers require more power than federal resources can supply, BPA would acquire the additional power to meet these needs from a resource stack in a least-cost-first sequence. This brings up the question of what can be included in BPA's resource stack in this hypothetical world.

An example is the Mid-Columbia resources not dedicated to public load (approximately 800 MW of hydropower, which are relatively cheap). The publics that own the Mid-Columbia dams sold a significant amount of the power to the IOUs by contract. If the Act is interpreted to mean that these Mid-Columbia resources sold to the IOUs can be included in BPA's resource stack in the hypothetical scenario, BPA's resource costs would be comparatively low. That would mean a surcharge is more likely to be added to the PF Exchange rate to ensure the publics aren't paying more than they would have in circumstances reflecting the five 7(b)(2) assumptions. This would reduce REP benefits.

If, however, the Act means that in the hypothetical case those Mid-Columbia resources dedicated to IOU load are unavailable to BPA, then BPA would have to go to the next cheapest resources in the resource stack, which is much more expensive than the Mid-Columbia hydro. This makes 7(b)(2) less likely to trigger, and therefore means higher REP benefits for the IOUs.

The issue of whether the Mid-Columbia resources could be included in the BPA resource stack came up in 1996 but turned out to be moot since at the time there were enough Federal Base System resources to meet public needs without these additional resources. At the time, BPA assumed that only the resources exported could be included in the resource stack.

The issue next arose in 2002, where it once again became moot. During the WP 2007 power rate case, the issue was not litigated because of a partial settlement. However, the next time BPA develops rates this is likely to be an issue as it remains an open question.

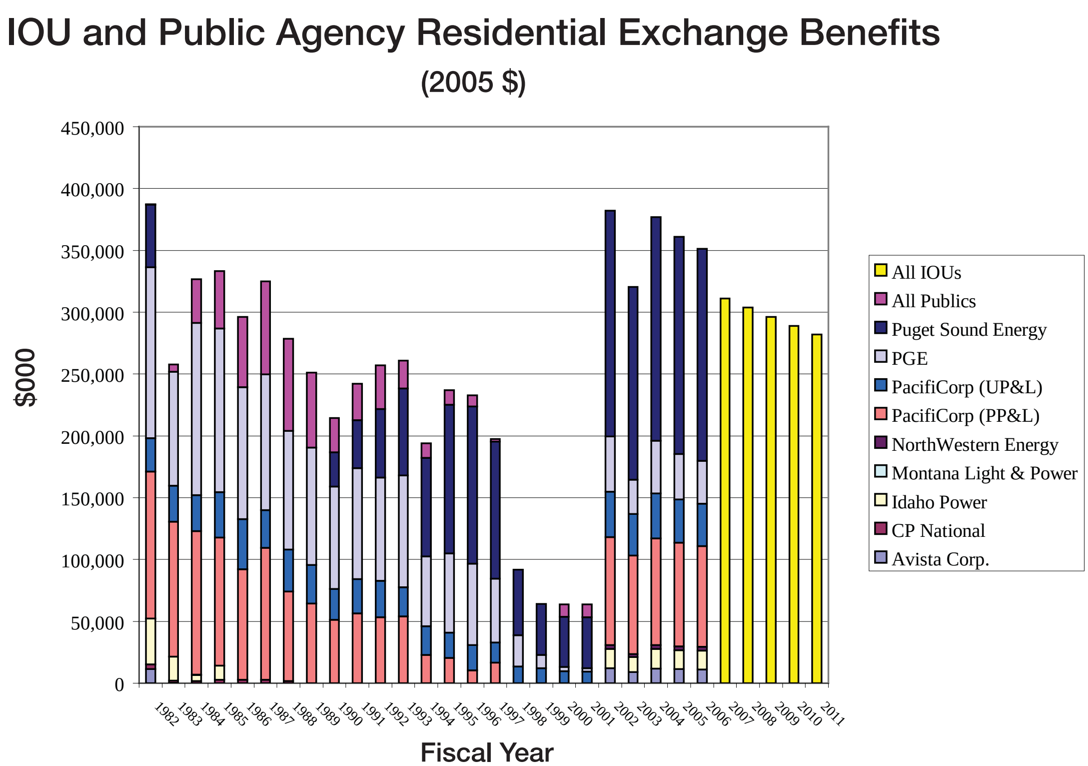
BPA has calculated that this issue alone would create a difference between the IOUs receiving $30 million annually versus $260 million annually. There are other similarly arcane issues that can swing the benefit levels substantially.

The concept of substituting a power sale for the "paper" exchange was discussed extensively during BPA's public involvement process for Subscription and was supported by many public utilities and other interests, as well as IOUs.

BPA's proposed settlement of REP issues had a value of $140 million a year to be provided in the form of both a power sale and money. BPA estimated that, under its traditional calculation of REP benefits, the IOUs would receive $48 million annually for the FY 2002-2006 period. The IOUs were advancing a position under which payments could be $323 million or more annually. The IOUs' agreements, which were for 10 years, provided power at a specified rate – to be determined in a Section 7(i) rate hearing – and stipulated monetary benefits were to be paid based on a comparison of the REP settlement power rate and at a rate related to market prices.

BPA offered the IOUs 1,800 aMW for the FY 2002-2006 period with 1,000 aMW in the form of power and the rest as cash payments. BPA also offered to provide 2,200 aMW during the 2007-2011 period. The intent at the time was that the 2,200 aMW would be entirely physical power deliveries, although whether the benefits would be power, monetary or a mixture was not decided. BPA felt that such power deliveries would be possible due to the expiration of existing long-term surplus sales and public power's interest in diversification due to market conditions. This theory did not anticipate the West Coast energy crisis along with its impact on the value of power, public power's willingness to buy from BPA and the impacts on IOU and BPA rates.

Through the settlement, BPA hoped to resolve long-standing REP disputes, eliminate the administrative burden of implementing the REP (i.e., processing average system costs, filings, etc.) and align the interests of the IOUs with BPA and its other customers by providing them benefits comparable to what would have been provided within the range of possible REP outcomes. BPA also hoped to provide longer-term certainty through the settlements.



FYs 2007 through 2011 benefits were computed prior to the May 3, 2007, 9th Circuit decision.

All six IOUs elected to execute 2000 REP Settlement Agreements. The state public utility commissions recommended how the benefits of the settlement would be allocated among the IOUs and asked for an additional 100 aMW for FY 2002-2006. BPA's decision making leading to adoption of these recommendations involved extensive public review.

The publics go to court

Within 90 days of the execution of the 2000 REP Settlement Agreements, a number of Northwest public power entities challenged the agreements in the Ninth Circuit Court of Appeals. Some IOUs filed petitions, but the basis for such petitions was resolved shortly thereafter. The petitions were consolidated into *Portland General Electric Co. v. Bonneville Power Administration.*[9]

The public agencies alleged the settlements provided more benefits to the IOUs than the Northwest Power Act allowed. The parties argued that BPA lacked statutory authority to settle disputes under the REP as proposed and that the 2000 REP Settlement Agreements must comply with Sections 5(c) and 7(b) of the Northwest Power Act. They said that, by executing the settlements, BPA did not comply because it failed to implement the ASC Methodology, in lieu transactions and BPA's PF Exchange rate based on the 7(b)(2) test. BPA believed it complied with the law because it considered all of these factors in establishing the REP settlements.

West Coast power crisis shocks region

By the summer of 2000, West Coast power prices were escalating rapidly. As a result, public power customers were showing increasing interest in placing substantial amounts of load on BPA for the post-2001 period. By the time contracts were signed in October 2000, it was apparent that BPA would need to acquire approximately 3,000 aMW beyond its existing supply to meet its contractual commitments to public utilities, IOUs and DSIs with deliveries to begin in October 2001.

In the winter of 2001, wholesale power prices exploded. BPA estimated that it would need to raise rates 250 percent if it were to acquire the full 3,000 aMW at the then current prices. In the first six months of FY 2001 alone, BPA spent more than $1 billion buying power. Facing this extreme situation, BPA developed a three-pronged load reduction program that included conservation, reductions in power demand by utilities and load curtailments by DSIs.

In May and June of 2001, BPA executed 2001 Load Reduction Agreements with Pacific and Puget, eliminating BPA's obligation to deliver power for the FY 2002-2006 period in exchange for cash payments. The IOU agreements were structured so that BPA's payment in FY 2002 was lower than the FY 2003-2006 annual payments. These agreements to forego power deliveries in exchange for a cash payment eliminated BPA's need to buy large amounts of more costly power on the market.

While the efforts to reduce BPA costs were largely successful, public power utilities still saw their rates go up 45 percent in October 2001. At the same time, IOU REP benefits to Pacific and Puget increased substantially as a result of the load reduction agreements. Some public utilities whose rates historically had been much lower than those of neighboring IOUs suddenly found themselves having to raise their residential rates above those of IOUs. Total benefits flowing to the IOUs' residential and small-farm consumers, including payments to reduce load on BPA, rose to about $370 million annually, compared to $58 million annually in the previous rate period.

BPA moves to lower public rates

An extended drought in the Northwest made it difficult for BPA to recover financially from the West Coast energy crisis and thus to lower power rates for public utilities. BPA looked for new initiatives that could further lower its costs and bring about rate reductions.

[9] Such cases are often referred to by the name of the first petitioner.

In 2003, BPA proposed a global REP litigation settlement with all BPA customers that was designed to provide rate relief for public utilities. The settlement was fragile from the start because it required support of nearly 100 preference customers that were parties to various lawsuits. The 2003 Litigation Settlement ROD provided that, among other things, if any preference customer failed to sign the stipulation and other settlement documents within 90 days after the effective date (Jan. 21, 2004), the proposed settlement would be void.

The proposed settlement would have decreased FY 2004 rates for public utilities by 7 percent (from what they otherwise would have been) by eliminating $200 million in IOU REP benefits and deferring another $270 million of benefits into the five-year rate period beginning in 2007. The proposed settlement also would have settled lawsuits brought by public utility customers regarding the level of benefits going to IOU customers.

The settlement proposal failed for lack of sufficient signatures. BPA received support from 86 customers, while six opposed the settlement and others did not respond formally.

Settlement "lite" offered

After the failure of the proposed global litigation settlement, in 2004 BPA proposed contract amendments to the underlying IOU settlements. This came to be known as "settlement lite."

In April 2004, BPA sent a letter asking for comment on a proposal in which Pacific and Puget would waive $160 million of payments between 2004-2006 and defer another $100 million, plus interest, until FY 2007-2011 when BPA expected to be on better financial footing. The amendments offered similar terms to the other IOUs, and all six signed agreements.[10] In return, the IOUs would receive greater certainty about their benefits. The benefits were defined as financial payments, not power deliveries. The proposed agreement established a floor of $100 million a year with an annual cap of $300 million for FY 2007-2011. By removing the $200 million from power costs, FY 2005-06 power rates were 6 percent lower than they otherwise would have been. The majority of commenters approved the proposal.

The IOUs agreed to the new settlement primarily because it gave them greater certainty as to how post-2006 benefits would be calculated. On May 25, 2004, BPA published the 2004 Agreements Regarding Payment ROD adopting the proposal to amend the underlying agreements.

Clark requests exchange

In June 2005, Clark Public Utilities, headquartered in Vancouver, Wash., sent BPA a letter requesting exchange benefits. Clark had experienced a sharp rise in its fuel costs for its gas-fired plant. Historically, while the bulk of exchange benefits had gone to IOUs, over the years more than 30 publicly owned Northwest utilities had participated in the program. All previously participating publics either had terminated contracts or settled the amount of their benefits.

BPA offered Clark an RPSA, which Clark signed in August 2005. This initiated the analysis to determine the utility's REP benefits. The following December, BPA and Clark reached a settlement, with exchange benefits scheduled to go into effect in January 2006. As part of the settlement, Clark returned to BPA's control area and replaced its power purchase contract with a partial service product.

REP discussed as part of Regional Dialogue

Since 2002, BPA has engaged with the region in a Regional Dialogue aimed at defining BPA's future power sales role after 2011 when current wholesale power contracts with preference customers expire.

The future of the REP has been a prominent part of these discussions involving both public and investor-owned utilities. These discussions, extending over five years, focused on forging a regional consensus on

[10] Certain provisions for Avista, Idaho Power, NorthWestern and PGE were different from those in Pacific's and Puget's contracts.

a new financial formula to settle REP disputes for the 2012-2027 period. While no agreement was reached, the parties did narrow their differences and were prepared to continue discussions. BPA and the IOUs agreed on principles for a new settlement, but further progress was put on hold after the Ninth Circuit decision on May 3, 2007.

Ninth Circuit weighs in

On that date, the U.S. Ninth Circuit Court of Appeals ruled on two lawsuits that had Residential Exchange implications. The first suit is known as the PGE (Portland General Electric) suit and was filed against BPA by numerous parties challenging BPA's 2000 REP Settlement Agreements with six IOUs (for the FY 2002-2011 contract period). Public utilities were the primary petitioners, although investor-owned utilities and industrial customers also filed petitions.

In the PGE case, the Court held that BPA exceeded its settlement authority and concluded that the settlement was not consistent with Sections 5(c) and 7(b) of the Northwest Power Act, which established the Residential Exchange Program. The Court also said BPA avoided the full statutory scheme of protecting preference customers under Section 7(b)(2).

The second lawsuit, known as the *Golden Northwest* suit, addressed, among other things, BPA's FY 2002-2006 power rates. In this case, the Western Public Agencies Group, Public Power Council and Grays Harbor PUD had contended BPA improperly allocated costs of the REP settlements to the PF Preference rate. The Court referred to its ruling in the PGE case, noting that the IOU settlements were unlawful. The Court held BPA should not have allocated costs of the settlement as business costs under Section 7(g) of the Northwest Act.

At the time of the Court's decision, the IOUs had collectively been receiving about $327 million in annual benefits. As a result of the Court's hearing, BPA formally notified the IOUs[11] in writing of its decision to suspend REP settlement payments immediately due to the uncertainty created by the recent Ninth Circuit Court rulings. BPA certifying officials are personally liable if payments are made that are not consistent with law, and, in this case, the Court's rulings created substantial questions over whether additional settlement payments are consistent with the law. These payments amounted to about $28 million each month to investor-owned utilities for their residential and small-farm consumers.

[11] The IOUs involved include Portland General Electric, Pacific Power, Rocky Mountain Power, Avista, Puget Sound Energy, Idaho Power and Northwest Energy. At the time of the settlement, Rocky Mountain Power was part of PacifiCorp, parent of Pacific Power.