11.0 RESIDENTIAL EXCHANGE AVERAGE SYSTEM COSTS, LOAD FORECASTS AND POLICY

11.1 Introduction

Many of the following arguments were raised in the parties' initial briefs and are identical to the arguments raised in their briefs on exceptions. BPA will retain citations to the parties' initial briefs in the discussions in this chapter, and may not add additional citations to briefs on exceptions unless new or different arguments are presented.

The Northwest Power Act, 16 U.S.C. §839 *et seq*., created the REP to provide residential and small farm customers of PNW utilities a form of access to low-cost Federal power. Boling and Doubleday, WP-02-E-BPA-30, at 1-5. Under the Northwest Power Act, BPA "purchases" power from each participating utility at that utility's ASC. *Id.* The Administrator then offers, in exchange, to "sell" an equivalent amount of electric power to the utility at BPA's PF Exchange power rate. *Id.* The amount of power purchased and sold is the qualifying residential and small farm load of each utility participating in the REP. *Id.* The Northwest Power Act requires that the net benefits of the REP be passed on directly to the residential and small farm customers of the participating utilities. *Id.*

The REP does not involve a conventional purchase and sale of power. *Id.* Under the normal implementation of the REP, no actual power is transferred either to or from BPA. *Id.* The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA and the less expensive power "sold" to the participating utility. *Id.* As discussed below, however, actual power sales may occur under "in-lieu" transactions, where BPA purchases power from a source other than the utility and sells actual power to the utility. *Id.*

With regard to the current status of the REP, Residential Exchange Termination Agreements have been negotiated with all but one of the previously active exchanging utilities. *Id.* The only remaining utility with an "active" Residential Purchase and Sale Agreement (RPSA) is MPC, which receives no REP benefits. *Id.* MPC continues to be in "deemer" status. *Id.* When a utility's ASC is less than the PF Exchange Program rate, the utility may elect to deem its ASC equal to the PF Exchange Program rate. *Id.* By doing so, it avoids making actual monetary payments to BPA. *Id.* The amount that the utility would otherwise pay BPA is tracked in a "deemer account." *Id.* At such time as the utility's ASC is higher than BPA's PF Exchange rate, benefits that would otherwise be paid to the utility act as a credit against the negative "deemer balance." *Id.* Only after the "positive benefits" have completely offset the "negative balance," bringing the negative "deemer account" to zero, would the utility again receive actual monetary payments from BPA. *Id.* Avista Corporation (Avista) and Idaho Power both terminated their RPSAs in 1993. *Id.* The issue of deemer balances with these utilities is currently in dispute. *Id.*

Each exchanging utility's ASC is determined by the Administrator according to the 1984 ASC Methodology, an administrative rule developed by BPA in consultation with its customers. *Id.* A utility's ASC is the sum of a utility's production and transmission-related costs (Contract

System Costs) divided by the utility's system load (Contract System Load). *Id.* A utility's system load is the firm energy load used to establish retail rates. *Id.* While BPA has used the ASC Methodology for its ASC determinations, it should be noted that the ASC Methodology can be revised. *Id*. Regional IOUs have advocated the revision of the ASC Methodology to eliminate the changes made in 1984. *Id.* In the event that the ASC Methodology were revised in the manner advocated by the IOUs, forecasted exchange benefits would increase significantly. *Id.*

BPA uses a "jurisdictional approach" in determining utilities' ASCs, which relies upon cost data approved by state public utility commissions (in the case of IOUs) and utility governing bodies (in the case of public utilities) for retail ratemaking. *Id.* These data provide the starting point for BPA's determination of the ASC of each utility participating in the REP. *Id.* Costs that have not been approved for retail rates are not considered for inclusion in Contract System Costs. *Id.*

The schedule for filing and reviewing a utility's ASC is established in the 1984 ASC Methodology, which provides that "not later than five working days after filing for a jurisdictional rate change or otherwise commencing a rate change proceeding, the utility shall file a preliminary Appendix 1, setting forth the costs proposed by the utility and shall deliver to BPA all information initially provided to the state commission." *Id.* The filing includes all testimony and exhibits filed in the retail rate proceeding. *Id.* Not later than 20 days following the effective date of new rate schedules in a jurisdiction, the utility must file a revised Appendix 1 reflecting costs as approved by the state commission or utility governing body. *Id.* BPA then has 210 days to review the filing and issue a report signed by the Administrator. *Id.* During this review process, BPA ensures that the costs and loads conform to the rules and requirements of the ASC Methodology, as well as the applicable provisions of the Northwest Power Act. *Id.* BPA makes adjustments as necessary. *Id.*

The gross cost of the REP is the total dollar amount that BPA pays for the power it "purchases" from participating utilities, including utilities in deemer status. *Id.* In the case of an in-lieu transaction, as discussed in Issue 4 below, the gross cost of the REP includes the cost of an in-lieu resource. *Id.* The gross revenue is the total dollar amount that BPA receives from participating utilities for its subsequent "sale" of power to them at the PF Exchange rate. *Id.* The net cost of the Program is the difference between gross cost and gross revenue, plus the Program implementation costs. *Id.*

BPA assumes that the REP will continue to exist during the rate period. *Id.* However, BPA's Subscription Strategy proposes a settlement of the REP for IOUs that includes a power sale and a financial component. *Id.* Because BPA does not know whether eligible utilities will continue participation in the REP or agree to a settlement of the REP, BPA must establish a rate that applies to the continued implementation of the REP. *Id.*

11.2 Forecast of Average System Cost and Loads for Exchanging Utilities

In the past, an exchanging utility's ASC forecast was typically based on the costs included in its last approved ASC Report signed by the Administrator. Boling and Doubleday, WP-02-E-BPA-30, at 5. Such costs were then adjusted to account for inflation, power purchases, and resource additions, and applied to forecasted loads for future periods to calculate the forecasted ASC. *Id.* Because of the Residential Exchange Termination Agreements noted above, BPA no longer receives cost and load data from utilities through ASC filings as was previously required and provided under the RPSAs. *Id.* BPA has therefore used a variety of data sources and approaches to determine ASCs. *Id.*

BPA's first step in developing ASCs was to identify which of BPA's many public agency and IOU customers might have ASCs that would be high enough to ensure positive exchange benefits and should therefore be evaluated in detail. *Id.* at 6. Utilities that executed Residential Exchange Termination Agreements that extend through 2011 were eliminated. *Id.* BPA then determined a proxy for the new PF Exchange rate. *Id.* Utilities' ASCs would need to exceed this rate in order to receive positive exchange benefits. *Id.* In developing the proxy rate, BPA noted that the section 7(b)(2) rate test triggered in BPA's 1996 rate case, and the 1996 PF Exchange rate was 32.7 mills/kWh. *Id.* BPA then reviewed some of the fundamental elements of the 1996 section 7(b)(2) rate test to determine whether it was likely that the trigger for the PF-02 rate period would be similar, and therefore the PF Exchange rate would be similar. *Id.* BPA noted that BPA's generation costs after revenue credits had remained relatively flat since the 1996 rate case; that exchanging utilities' ASCs were increasing over time; and that the value of reserves credit for the DSIs had diminished. *Id.* These factors suggested that the new trigger amount and the new PF Exchange rate would likely be at least as high as the previous trigger amount and 1996 PF Exchange rate. *Id.* Based on ASCs that were current or forecasted at the time the Residential Exchange Termination Agreements were negotiated, BPA assumed that Puget Sound Energy (PSE), PGE, the Pacific Power and Utah Power Divisions of PacifiCorp, and MPC might have relatively high ASCs. *Id.* In addition, as discussed in greater detail below, BPA used simplifying assumptions to estimate whether Avista and Idaho Power were likely to be candidates for Exchange benefits during the rate period. *Id.* Among public utilities, Clark County Public Utility District (PUD), Snohomish County PUD, and the City of Idaho Falls were considered possible candidates to have relatively high ASCs. *Id.* Each utility has generating resources and had a relatively high ASC at the time it negotiated a Residential Exchange Termination Agreement. *Id.* at 6-7.

To forecast ASCs for PacifiCorp (the Pacific Power and Utah Power Divisions), PSE, PGE, and MPC, BPA developed a Microsoft Excel-based model to replace the ASC forecasting function that was performed by a mainframe computer model in BPA's 1996 rate case. *Id.* at 7. BPA developed a new model for a number of reasons. *Id*. The mainframe model was expensive to maintain and to run. *Id.* The model was also difficult for parties in BPA's rate case to understand and replicate. *Id.* Desktop computer technology had improved to where it was possible to build spreadsheet-based models that could perform many of the applications of the mainframe model. *Id.*

The ASC forecasting methodology of the new model is consistent with the old model. *Id.* The new model adjusts costs to account for price changes and inflation, replaces and depreciates production plant based on historical activity, and accounts for power purchases and sales. *Id.* The new model, however, is simpler to operate than the old model. *Id*. The new model, unlike the old model, does not calculate gross cost, gross revenue, and net cost as they are applied to the REP. *Id.* This function is now calculated by an Exchange cost model linked to the RAM, which simplifies the iterative process required to achieve stable PF rates and Exchange costs. *Id.* *See* Wholesale Power Rate Development Study, WP-02-E-BPA-05, section 3.2.1.3.

The starting point expense data used as the basis for forecasting rate period ASCs are essentially the same data used in BPA's 1996 rate case. Boling and Doubleday, WP-02-E-BPA-30, at 7. Plant replacement factors have been adjusted to reflect the most current five years of plant retirement activity, and expenses have been adjusted using current escalators. *Id.* In addition, given possible industry restructuring and uncertain market conditions, BPA assumed for ASC forecasting purposes that utility load growth will be satisfied with purchased power. *Id.* at 7-8. Such purchases are assumed to be at 28.1 mills/kWh, BPA's forecast of five-year flat-block purchases, plus a transmission charge. *Id.* at 8. The testimony of Oliver *et al.*, WP-02-E-BPA-20, describes the derivation of the five-year flat-block price forecast. *Id.* *See also* ROD section 10.11. This forecast is appropriate, because exchanging utilities will make long-term purchases to meet load growth. Boling and Doubleday, WP-02-E-BPA-30, at 7. BPA based the transmission charge on the PTP rate (currently $1.00 per kW-month), which was assumed to increase to $1.48 per kW-month in BPA's next TBL rate case. *Id.* The $1.48 rate was assumed to be constant through FY 2010. *Id.* BPA then assumed an energy loss rate of 2 percent and flat delivery. *Id.* Converting these adjustments to an energy-only charge resulted in a rate of 2.07 mills/kWh. *Id.* BPA then assumed that the foregoing energy losses were valued at 28.1 mills/kWh, resulting in a cost of transmission with losses of 2.63 mills/kWh in FY 2002. *Id.*

BPA has adjusted PGE's Contract System Costs based on the functionalization of certain benefits from PGE's merger with Enron, as directed by the OPUC in Order Number 97-196. *Id.* The OPUC's order specified that $105 million in benefits relating to use of PGE's name and other intangibles be distributed with interest over eight years beginning in 1997. *Id.* The order further specified that $36 million in cost of service savings be distributed with interest over four years beginning in 1998. *Id.* Based on the ratio of exchangeable plant in service to total plant in service (the "PTDG ratio") taken from PGE's ASC filing that was suspended when PGE's Residential Exchange Termination Agreement was negotiated, BPA assumed that 60 percent of such merger benefits would reduce Contract System Costs. *Id.* This results in a $9.7 million reduction to PGE's Contract System Costs during the first three years of BPA's rate period, FY 2002-2004. *Id.*

The test years of the most recent ASC filings for Avista and Idaho Power are 1983 and 1984, respectively. *Id.* at 9. With such old data, BPA estimated proxy ASCs for 1997. *Id.* BPA determined prior ASCs as a percentage of average residential revenue per kWh sold for the test years and applied those percentages to average residential revenue per kWh sold for 1997. *Id.* The post-1997 ASCs for Avista and Idaho Power were escalated at 2.5 percent annually. *Id.* This escalation rate is equal to the simple average annual rate of growth in ASC for MPC, PGE, PSE, and the Pacific Power and Utah Power divisions of PacifiCorp for the FY 1999-2010 period. *Id.*

Load forecasts for PacifiCorp and PGE were based on data submitted by the utilities and used in BPA's 1996 rate case. *Id.* Load forecasts that did not extend through FY 2010 were escalated at average annual rates of growth during the utility's forecast period. *Id.* Load forecasts for MPC and PSE are based on utility forecasts submitted to BPA in March 1998. *Id.* Loads for Idaho Power were estimated from publicly available data in early 1998. *Id.* Residential loads for Avista were estimated by reviewing current total utility load data and residential loads that had been provided by Avista for FY 1995. *Id.*

Because Clark County PUD, Snohomish County PUD, and the City of Idaho Falls terminated their RPSAs so long ago, it is unwise to project such obsolete cost data ahead 10 or more years just to determine ASCs for the first year of BPA's rate period. *Id.* Instead, with the cooperation of utility staff, BPA staff estimated current ASCs for Clark and Idaho Falls using BPA's Excel-based ASC evaluation template. *Id.* Such ASCs were then escalated at 2.2 percent annually through FY 2010. *Id.* This escalation factor is lower than the escalation factor applied to Avista's and Idaho Power's ASCs, described above. *Id.* The escalator applied to Avista and Idaho Power is significantly influenced by the assumption that load growth is satisfied by purchases at 28.1 mills/kWh. *Id.* Clark and Idaho Falls have access to BPA's preference power at rates lower than BPA's five-year flat-block price forecast for their net requirements. *Id.* at 9-10. To estimate the effect of lower purchased power costs on ASC, BPA determined the simple average annual rate of growth in ASC for MPC, PGE, PSE, and the Pacific Power and Utah Power divisions of PacifiCorp for the FY 1999-2010 period, substituting the PF-96 rate for the higher 28.1 mills/kWh price that was used to estimate the IOUs' ASCs. *Id.* at 10. Using the lower PF-96 rate for load growth-driven purchased power yielded the lower escalation rate for Clark and Idaho Falls. *Id.* Both Clark and Idaho Falls provided current load forecasts. *Id.*

Using 1997 annual report data, Snohomish PUD's ASC was estimated to be 30.87 mills/kWh. *Id.* Snohomish's ASC effective October 1, 2001, is estimated to be 30.07 mills/kWh. *Id.* This reduction is largely based on assumptions of reduced purchased power costs. *Id.* Snohomish's ASC was then escalated at the same annual rate, 2.2 percent, that was applied to Clark and Idaho Falls. *Id.*

Issue 1

Whether BPA properly included transmission costs in its development of ASC forecasts.

Parties' Positions

The DSIs argue that BPA used excessive ASC estimates for the IOUs, such as by relying on stale, dated data. DSI Brief, WP-02-B-DS-01, at 66; DSI Ex. Brief, WP-02-R-DS-01, at 2-66. The Joint DSIs argued that BPA has improperly included transmission costs in the development of its ASC forecasts. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 18; DSI Ex. Brief, WP-02-R-DS-01, at 2-67.

BPA's Position

BPA has properly included transmission costs in its development of ASC forecasts. Boling and Doubleday, WP-02-E-BPA-30, at 5-10; Boling and Doubleday, WP-02-E-BPA-53, at 8-12.

Evaluation of Positions

The DSIs argue that BPA used excessive ASC estimates for the IOUs by relying on stale, dated data. DSI Brief, WP-02-B-DS-01, at 66. The individual arguments regarding ASCs that were raised by the DSIs are addressed in greater detail below.

The Joint DSIs argued that the transmission costs BPA has included in ASCs are incorrect because, due to the Energy Policy Act of 1992 (EPA-92) and FERC Order 888, BPA has the means to determine which transmission costs are resource costs for purposes for inclusion in a utility's ASC and which are not. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 18. ASCs must be established consistent with BPA's ASC Methodology. Boling and Doubleday, WP-02-E-BPA-53, at 8. BPA has properly included transmission costs in its ASC forecasts. *Id.* While the ASC Methodology may be changed in the future, BPA has an existing methodology, and it is not known what possible changes would be made in developing a subsequent methodology. *Id.* It is therefore, appropriate for purposes of this rate proceeding to use the current ASC Methodology in making ASC forecasts. *Id.* BPA's forecasted ASCs include transmission costs that have been (or would be) allowed consistent with the current ASC Methodology, escalated based on assumptions regarding inflation and plant additions and retirements. *Id.* Basing ASC forecasts on transmission costs that are determined to be resource costs due to EPA-92 and FERC Order 888 would be inconsistent with the ASC Methodology. *Id.*

The Joint DSIs argued that all costs that FERC allows a utility to recover under its open access transmission tariff should be excluded from a utility's ASC, and all transmission costs FERC assigns to generation for ratemaking purposes should be allowed as part of a utility's ASC. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 18. As noted above, ASCs must be determined in accordance with BPA's ASC Methodology. Boling and Doubleday, WP-02-E-BPA-53, at 8. The Joint DSIs' proposal would require that BPA's ASC forecasts determine exchangeable transmission costs differently than prescribed by the current ASC Methodology. *Id.* While the Joint DSIs may advocate changes in the determination of eligible costs in a future proceeding to develop a new ASC Methodology, BPA's forecasts are properly based on the requirements of the current ASC Methodology rather than a speculative new methodology. *Id.* at 8-9.

The Joint DSIs argued that the estimation of generation-integration and generator step-up transformation costs for utilities should be based on the same percentage of those costs to transmission costs for BPA, which is 2.8 percent. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 19. Again, the Joint DSIs' recommended approach is inconsistent with the current ASC Methodology, which is properly used for the forecast of exchange costs in this rate proceeding. Boling and Doubleday, WP-02-E-BPA-53, at 9.

The Joint DSIs' estimates of the ASCs of exchanging utilities included generation-integration and GSU costs, but because BPA's PF Exchange rate is a delivered rate, they added BPA's transmission costs to their forecasted ASCs to compute the net cost of the exchange and did not assume that additional transmission costs would be exchanged. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 19. Since the PF Exchange rate is a delivered rate, it is appropriate that ASCs include transmission costs when determining net exchange costs. Boling and Doubleday, WP-02-E-BPA-53, at 9. The Joint DSIs, however, essentially have substituted BPA's transmission costs in the ASC determination for the utilities' own transmission costs. *Id.* This approach is inconsistent with the current ASC Methodology. *Id.*

The Joint DSIs argued that BPA should not include any estimate of its own transmission costs other than GI and GSU costs when it forecasts the net cost of the exchange; that is, the PF Exchange rate should be developed to be a power-only rate. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 19. Utilities' ASCs include transmission costs under the current ASC Methodology. Boling and Doubleday, WP-02-E-BPA-53, at 9. Under the traditional implementation of the REP, BPA's PF Exchange rate has also included transmission costs in order to establish an apples-to-apples comparison for purposes of determining exchange benefits. *Id.* Given the current ASC Methodology, it would be inappropriate to exclude transmission costs from the PF Exchange rate. *Id.* at 9-10.

Decision

BPA properly included transmission costs in the development of ASC forecasts.

Issue 2

Whether BPA properly forecasted ASCs for Avista and Idaho Power.

Parties' Positions

The DSIs argue that BPA used excessive ASC estimates for the IOUs, such as by relying on stale, dated data. DSI Brief, WP-02-B-DS-01, at 66. The Joint DSIs argued that BPA improperly calculated the ASCs for Avista and Idaho Power. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 20.

BPA's Position

BPA has properly forecasted ASCs for Avista and Idaho Power. Boling and Doubleday, WP-02-E-BPA-53, at 10-11.

Evaluation of Positions

The Joint DSIs argued that BPA's calculations of ASCs for Avista and Idaho Power are based on an assumption that generation, transmission, and distribution costs are growing in the same proportion, which is not true. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 20. The Joint DSIs argued that it is incorrect to tie the ASC, which is based only on generation and some transmission costs, to any change in the residential rate, which has been driven mainly by changes in distribution costs that are not exchangeable. *Id.* BPA estimated current ASCs for Avista and Idaho Power by adjusting the utilities' last approved ASCs based on changes to the utilities' average residential rates. Boling and Doubleday, WP-02-E-BPA-53, at 10. The DSIs asserted that non-exchangeable distribution costs have been driving changes in Avista's and

Idaho Power's residential rates. *Id.* This, however, is not the case. *Id.* The DSIs' contention was based on an incomplete assumption and incorrect data. *Id.* The DSIs assumed that changes in net plant would be a good indicator of changes in rates and exchangeable costs. *Id.* While this may be one element, it is revenue requirement, not net plant, which drives changes in rates. *Id.* It is true that distribution net plant has grown faster than production and transmission plant for both companies since 1990. *Id.* However, only 62 percent of Avista's and 39 percent of Idaho Power's net plant growth is due to distribution, whereas the DSIs calculated 93 percent and 89 percent, respectively. *Id.* Regardless, changes in net plant do not directly lead to changes in revenue requirements and rates. *Id.* Net plant affects rates through depreciation, interest, and rate of return. *Id.* Such amounts for Avista and Idaho Power are offset or even outweighed by the respective increases that have occurred in production and transmission O&M expense, most of which is directly exchangeable. *Id.* Based on FERC Form 1 data for 1990 and 1998, Avista's production and transmission O&M expense (less purchased power) has increased $58 million, or 53 percent. *Id.* Idaho Power's production and transmission O&M expense (less purchased power) has increased $54 million, or 27 percent. *Id.* at 10-11. Thus, increases in production and transmission O&M expense for the two utilities, most of which is exchangeable, is a more important determinant of ASC than is growth in distribution plant. *Id.* at 11.

The Joint DSIs argued that another problem with BPA's proxy is that it does not take into account the large increase in other revenues that are credited against the ASC, citing Avista and Idaho Power's sales for resale. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 20-21. Avista's growth in sales for resale revenue cited by the DSIs was $362 million. Boling and Doubleday, WP-02-E-BPA-53, at 11. This potential credit against ASC, however, would be more than offset by increased purchased power costs of $404 million. *Id.* Idaho Power's sales for resale revenue growth was $536 million, whereas its purchased power costs increased $496 million. *Id.*

The Joint DSIs attempted to follow the ASC Methodology and develop ASCs for Avista and Idaho Power based on 1998 FERC Form 1 data, including only the production expenses and return on production assets and a portion of transmission costs representing GI and generator step-up transmission, then escalating these 1998 ASCs in the same way BPA escalated the PacifiCorp, PSE, PGE, and MPC ASCs. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 21. Under the current ASC Methodology, BPA does not determine ASCs based on FERC Form 1 data. Boling and Doubleday, WP-02-E-BPA-53, at 11. In fact, when BPA revised the ASC Methodology in 1984, one possible revision considered by BPA involved the use of FERC Form 1 information to determine ASCs. *Id.* This approach was widely criticized by parties and rejected by BPA and is not the basis for determining ASCs under the current ASC Methodology. *Id.* During the implementation of the REP since 1981, BPA has periodically estimated ASCs from FERC Form 1 data and then compared the results to an approved ASC. *Id.* at 11-12. Such estimates consistently differed from approved ASCs, often by large margins and in no predictable direction. *Id.* at 12. Therefore, the DSIs' estimates are likely to be flawed. *Id.* In addition to problems inherent in using FERC Form 1 data, the DSIs used only a portion of transmission costs representing GI and generator step-up transmission in their ASC forecasts. *Id.* As noted above, including only GI and generator step-up transmission costs in ASC is inconsistent with the ASC Methodology. *Id.*

Including only generation-integration and generator step-up transmission costs in ASC, as discussed above, reduced BPA's forecasted five-year rate period ASCs for MPC, PacifiCorp (Pacific Power and Light and Utah Power and Light Divisions), PGE, and PSE by an average of 4.71 mills/kWh. Boling and Doubleday, WP-02-E-BPA-53, at 12. *See* Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 21. Adding this transmission cost component to the five-year average ASCs for Avista and Idaho Power that were estimated by the DSIs results in ASCs of 23.71 mills/kWh and 22.30 mills/kWh, respectively. Boling and Doubleday, WP-02-E-BPA-53, at 12. ASCs at this level would likely have the same effect as the ASCs estimated by BPA, *i.e.*, neither utility is forecasted to receive Residential Exchange benefits under the current proposal. *Id.*

<u>Decision</u>

BPA properly forecasted ASCs for Avista and Idaho Power.

<u>Issue 3</u>

Whether BPA properly forecasted in-lieu transactions for 50 percent of Residential Exchange load.

<u>Parties' Positions</u>

The DSIs argue that BPA should have assumed that it would in-lieu 100 percent of the purchases from certain IOUs under the REP. DSI Brief, WP-02-B-DS-01, at 66-67; DSI Ex. Brief, WP-02-R-DS-01, at 2-66 to 2-68. The DSIs contend that it is inappropriate for BPA to determine the amount of in-lieu transactions based on the goal of providing exchanging utilities additional, non-statutory benefits. DSI Ex. Brief, WP-02-R-DS-01, at 24. PPC argues that there is nothing to prevent BPA from in-lieuing a portion of the utility's eligible exchange load. PPC Brief, WP-02-B-PP-01, at 74.

<u>BPA's Position</u>

BPA has properly forecasted in-lieu transactions for 50 percent of Residential Exchange load. Boling and Doubleday, WP-02-E-BPA-30, at 10-16; Boling and Doubleday, WP-02-E-BPA-53, at 6.

<u>Evaluation of Positions</u>

Under section 5(c)(5) of the Northwest Power Act:

> . . . [T]he Administrator *may* acquire an equivalent amount of electric power from other sources to replace power sold to such utility as part of an exchange sale if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

16 U.S.C. §839c(c)(5) (emphasis added). This acquisition of power from other sources is "in-lieu" of the "purchase" that would otherwise occur under the REP, and is designed to provide a mechanism to limit the net costs of the Program. Boling and Doubleday, WP-02-E-BPA-30, at 10. An in-lieu transaction is not mandatory and is implemented subject to the Administrator's discretion consistent with applicable law and the applicable RPSA. Boling and Doubleday, WP-02-E-BPA-30, at 10. *See* PPC Brief, WP-02-B-PP-01, at 74.

BPA must determine which utilities are candidates for in-lieu transactions. In-lieu transactions are appropriate only for utilities with ASCs that exceed the PF Exchange rate. *Id.* at 11. BPA therefore would not in-lieu utilities with ASCs below BPA's PF Exchange rate. *Id.* In addition, where a utility's ASC is only slightly higher than the PF Exchange rate, it is inappropriate to assume an in-lieu transaction, because forecast error and the costs of implementation could make the in-lieu transaction uneconomic. *Id.* In-lieu transactions therefore, are financially sound only for utilities with ASCs significantly above the PF Exchange rate. *Id.* Finally, in-lieu transactions are financially sound only when the cost of the in-lieu resource is significantly below the utility's ASC. *Id.*

As noted above, the determination of which utilities would be subject to in-lieu transactions rests primarily on three factors: a utility's ASC, the cost of the in-lieu resource, and the PF Exchange rate. BPA's forecast of exchanging utilities' ASCs is discussed above. *Id.* Complete documentation of the exchanging utilities' ASCs is contained in the Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A. BPA's assumptions regarding the source and cost of in-lieu resources were as follows. BPA assumed that in-lieu resources could be acquired by market purchases. *Id.* The cost of such purchases is appropriately reflected by BPA's forecast of five-year flat-block purchases, adjusted to reflect shaped delivery. *Id.* *See* Oliver *et al.,* WP-02-E-BPA-20. Shaped delivery is based on PF-02 billing determinants. Boling and Doubleday, WP-02-E-BPA-30, at 11. Average energy prices from this forecast are 29.0 mills/kWh. *Id.* Since this market forecast is for undelivered energy, BPA assumed 3.40 mills/kWh for delivery based on the forecast of the transmission contribution to the PF Exchange Program rate. *Id.* *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 77.

Because in-lieu transactions are governed by the terms of the RPSAs, BPA had to make assumptions regarding the relevant provisions of the RPSAs during the rate period. Boling and Doubleday, WP-02-E-BPA-30, at 12. BPA has not yet negotiated new RPSAs for the period beginning in FY 2002. *Id.* BPA assumed that contract provisions for new RPSAs would not unduly limit BPA's statutory right to implement in-lieu transactions. *Id.* For example, the previous RPSAs included seven-year notice provisions for implementing in-lieu transactions based on the time needed to construct a new generating resource. *Id.* Given the changes in the utility industry since 1981 and the ability of utilities to acquire power much more quickly, BPA assumed that the notice period to begin an in-lieu transaction would be short enough to allow in-lieu transactions to begin in FY 2002 after the negotiation of new RPSAs. *Id.*

In order to determine which exchanging utilities would be subject to in-lieu transactions, BPA developed forecasted ASCs for the exchanging utilities. *Id.* BPA then compared the ASCs with a proxy for the new PF Exchange rate, which was determined to be at least as high as the

1996 PF Exchange rate. *Id.* BPA then compared the simple average of utilities' forecasted new ASCs over the rate period to the 1996 PF Exchange rate (32.7 mills/kWh), and determined that only four exchanging utilities were likely candidates for in-lieu transactions: MPC, PSE, PGE, and PacifiCorp's Utah Power Division. *Id.* MPC's ASC is forecasted to be 33.12 mills/kWh in 2002, increasing to 41.13 mills in 2010. *Id.* PSE's ASC is forecasted to be 39.01 mills/kWh in 2002, increasing to 47.01 mills in 2010. *Id.* PGE's ASC is forecasted to be 38.68 mills/kWh in 2002, increasing to 46.04 mills in 2010. *Id.* Utah Power's ASC is forecasted to be 37.93 mills/kWh in 2002, increasing to 43.27 mills in 2010. *Id.*

BPA then conducted preliminary runs of RAM reflecting the participation of the four IOUs. *Id.* While PSE, PGE, and PacifiCorp's Utah Power Division have ASCs significantly higher than the preliminary RAM PF Exchange rate, MPC's average ASC for the rate period was 35 mills/kWh, which was relatively close to the preliminary rate. *Id.* Because of MPC's small residential load (approximately 60 aMW), and the risk of forecast error and administrative costs making the in-lieu transaction uneconomic, BPA would not in-lieu MPC. *Id.* at 12-13.

BPA assumed that in-lieu transactions will occur beginning FY 2002 for 50 percent of the exchange loads of PSE, PGE, and PacifiCorp's southern Idaho jurisdiction of its Utah Power Division. Boling and Doubleday, WP-02-E-BPA-30, at 13. This averages 1,202 aMW over the rate period. *Id.* BPA assumed that the loads of all three utilities would be subject to in-lieu in order to spread the impact of in-lieu transactions among the three state jurisdictions of Washington, Oregon, and Idaho instead of placing the impact in a single jurisdiction. *Id.*

BPA proposed to in-lieu only 50 percent of the utilities' residential loads instead of a larger amount for a number of reasons. *Id.* As described above, in-lieu transactions are appropriate only for utilities with ASCs that exceed the PF Exchange rate. *Id.* The proposed PF Exchange Program rate of 37.11 mills/kWh is reasonably close to the utilities' ASCs in the early years of the rate period. *Id.* BPA is less inclined to assume a larger in-lieu amount where there are only small differences between ASCs and the PF Exchange rate. *Id.* In addition, BPA has limited the in-lieu amount to 50 percent to account for risk and uncertainty regarding forecasted ASCs, to reduce possible adverse effects to the utilities of receiving large in-lieu power deliveries on relatively short notice, and to ensure that some amount of benefits of Federal power would be provided to the residential and small farm consumers of the exchanging utilities. *Id.*

BPA is unsure whether, over the lengthy ASC forecast period, there will continue to be a significant difference between the expected price of in-lieu power and the ASCs of likely candidates for in-lieu transactions. *Id.* at 13-14. BPA is looking ahead more than two years until the start of the rate period, five years during the rate period, and then, for purposes of the section 7(b)(2) rate test, an additional four years. *Id.* at 14. While BPA's forecasts have been conducted in the most accurate manner possible, BPA is not developing its forecasts from current ASC reports. *Id.* As noted above, due to settlement of most exchanging utilities' RPSAs, BPA does not have information that is as accurate as was previously available to BPA. *Id.* In addition, ASCs are also subject to variation for reasons beyond BPA's control, such as market forces and industry restructuring. *Id.*

In addition, PSE, PGE, and the southern Idaho jurisdiction of PacifiCorp's Utah Division could be placed in a surplus condition under an actual delivery of PF power upon relatively short notice. *Id.* That is, the sale of power to an IOU under an in-lieu transaction could provide the utility with more resources than would be necessary to meets its loads, thereby rendering the utility surplus. *Id.* Disposing of such surplus could impose costs on the utilities and their customers if the revenue received for any resulting surplus sales should prove to be less than was paid for the power purchased from BPA. *Id.* Utilities' sales of their surplus might also require marketing Northwest resources outside the region. *Id.* Based on data taken from the 1997 Pacific Northwest Loads and Resources Study (Whitebook), in-lieu sales equal to 50 percent of the utilities' exchangeable loads would approximately equal the utilities' deficits and would help minimize the effect of displacing the utilities' resources. *Id.*

BPA also considered the adverse effects of reduced Exchange benefits in determining the in-lieu amount. *Id.* Absent a settlement, implementation of the REP is the manner in which residential and small farm customers of regional IOUs receive benefits of Federal power. *Id.* In-lieu transactions, while fiscally prudent for BPA, reduce Residential Exchange benefits. *Id.* at 14-15. Assuming 100 percent in-lieu transactions, for example, would completely eliminate residential exchange benefits where in-lieu resource costs are less than the PF Exchange rate. *Id.* at 15. This would eliminate nearly all benefits of Federal power received by the residential and small farm customers of IOUs. *Id.* In addition, the current proceeding highlights certain potential effects on exchange benefits that were not previously recognized by BPA. *Id.*

The anticipated effect on residential exchange benefit payments to PGE, PSE, and Utah Power from 50 percent in-lieu transactions with those utilities would be influenced by the forecast that in-lieu resource costs will be considerably lower than the PF Exchange rate. *Id.* Given this relationship, the effect then depends on the contract provisions that are assumed to be in place during the rate period to implement in-lieu transactions. *Id.* Under the 1981 RPSA, a utility had two options if BPA intended to implement an in-lieu transaction. *Id.* The utility could purchase actual power from BPA at the PF Exchange rate in the amount of the in-lieu transaction, or it could refuse the power and reduce its ASC to the cost of the in-lieu resource for the amount of the in-lieu transaction (in this case, 50 percent). *Id.* Under current conditions, where in-lieu resources are projected to cost considerably less than the PF Exchange rate, utilities would have no rational incentive to purchase power from BPA at greater than market prices. *Id.* The utility would opt instead to reduce its ASC to the in-lieu resource cost. *Id.* By reducing its ASC to resource cost for, in BPA's proposal, 50 percent of its exchange load, the utility might continue to receive exchange benefits for the remaining 50 percent of its exchange load. *Id.* The 1981 RPSA is silent, however, regarding the effect on total benefits associated with the reduced ASC portion of exchange load. *Id.*

There are different contract options to address the treatment of that portion of exchange load that has an ASC reduced below the PF Exchange rate. *Id.* at 16. One approach would have the "negative benefits" of the in-lieued portion of exchange load be offset against the positive benefits associated with the remaining exchange load. *Id.* This approach could result in net negative benefits to a utility. *Id.* This situation could occur if the difference between the utility's ASC and PF Exchange rate (positive benefits) is less than the difference between the PF Exchange rate and the in-lieu resource cost (negative benefits). *Id.* This option could create anomalous results. *Id.* For example, a utility could be required to pay money to BPA. *Id.* Also, a 100 percent in-lieu transaction could be of less benefit to BPA than a 50 percent in-lieu transaction. *Id.*

An alternative approach would assume that a new RPSA would allow a utility to terminate its participation in the REP for the in-lieued portion of its exchange load, where such load had its ASC reduced to the in-lieu resource cost and where such cost was less than the PF Exchange rate. *Id.* This would allow a utility to receive benefits for its remaining nonin-lieued exchange load. *Id.* Based on BPA's proposal of a 50 percent in-lieu of PGE, PSE, and Utah Power, each utility's exchange benefit would be reduced by approximately one-half. *Id.* This would avoid the possibility of zero, or even negative, benefits to a utility in a situation where some of the utility's exchange load is still actively exchanging. *Id.*

The DSIs argue that due to BPA's errors in determining exchange costs, the PF Exchange rate was set so high that no IOU would engage in an in-lieu transaction. DSI Brief, WP-02-B-DS-01, at 66. They argue that BPA therefore treated the in-lieu transaction as if it did not occur and simply reduced the exchange load by 50 percent. *Id.* The DSIs' argument is based upon false assumptions. First, as evidenced by the record in this proceeding, BPA properly established the PF Exchange rate. Further, as discussed in greater detail below, it is a reasonable assumption that where the cost of in-lieu power is less than the PF Exchange rate, it would not be economic for a utility to participate in an in-lieu transaction.

The DSIs note BPA's reasons for BPA's 50 percent in-lieu assumption. DSI Brief, WP-02-B-DS-01, at 66. The DSIs argue that BPA should increase the in-lieu assumption to 100 percent of the purchase from high-ASC utilities. *Id.* The DSIs argue that if it is economical to in-lieu 50 percent of a transaction, it is economical to in-lieu the entire purchase. *Id.* BPA disagrees. As noted previously, section 5(c)(5) of the Northwest Power Act provides:

> . . . [T]he Administrator *may* acquire an equivalent amount of electric power from other sources to replace power sold to such utility as part of an exchange sale if the cost of such acquisition is less than the cost of purchasing the electric power offered by such utility.

16 U.S.C. §839c(c)(5) (emphasis added). The Northwest Power Act is clear that BPA's decision to conduct an in-lieu transaction is discretionary, not mandatory. PPC notes that there is nothing to prevent BPA from in-lieuing a portion of the utility's eligible exchange load. PPC Brief, WP-02-B-PP-01, at 74. As previously noted, there are economic and other factors that are involved in a decision to in-lieu an exchanging utility. Boling and Doubleday, WP-02-E-BPA-53, at 6; Boling and Doubleday, WP-02-E-BPA-30, at 13. Even assuming for the sake of argument, however, that economic factors were the only criteria to be used in determining an in-lieu amount, BPA would still be reluctant to in-lieu 100 percent of exchange load. Boling and Doubleday, WP-02-E-BPA-53, at 6. The Joint DSIs admit that there should be "sufficient margin" between ASCs and the PF Exchange rate "to assure that there is a likelihood that the exchange transaction will actually occur." *Id.* Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 10. BPA noted in its direct testimony that the lack of current data to forecast ASCs, uncertainty regarding market forces, and industry restructuring create risk

and uncertainty that the utilities' ASCs could be less than the PF Exchange rate. Boling and Doubleday, WP-02-E-BPA-53, at 6; Boling and Doubleday, WP-02-E-BPA-30, at 13-14. Such risk has appropriately influenced BPA's economic assessment of in-lieu transactions. Boling and Doubleday, WP-02-E-BPA-53, at 6.

In addition, BPA placed considerable emphasis on certain noneconomic factors. *Id.* In-lieu transactions are neither mandatory nor required to be based solely upon economic considerations, but are exercised in the Administrator's discretion consistent with law. *Id.* In making its determination that BPA would in-lieu 50 percent of exchanging loads, BPA considered factors such as reducing the possible adverse impact that an in-lieu transaction might impose on an exchanging utility, and ensuring that some level of Federal power benefits would be available to the residential and small farm consumers of utilities that continue the REP. *Id.* A 100 percent in-lieu assumption would disregard these factors. *Id.* As noted previously, the PPC argues that there is nothing to prevent BPA from in-lieuing a portion of the utility's eligible exchange load. PPC Brief, WP-02-B-PP-01, at 74, citing Hansen *et al.*, WP-02-E-PP-09.

The Joint DSIs also argued that, for 100 percent in-lieued exchanges, BPA should calculate its own net cost of the exchange using the in-lieued price as a substitute for the ASC of the exchanging utility and treat the load as it would otherwise. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 10. The DSIs argued that BPA should assume that the utility deems its ASC to be equal to the purchase price of the in-lieu power. *Id.* They argued that if the in-lieu price is less than the PF Exchange rate, BPA should treat the utility as a deemer, and where the in-lieu price is greater than the PF Exchange rate, BPA should include the utility's load as if it were exchanging at its full ASC. *Id.* This approach is inappropriate. Boling and Doubleday, WP-02-E-BPA-53, at 7. This treatment of load would be appropriate only for a 100 percent in-lieu transaction. *Id.* If the in-lieu cost exceeds the PF Exchange rate, the utility's exchangeable load would continue to receive monetary benefits. *Id.* However, if the in-lieu cost is less than the PF Exchange rate, the utility's exchangeable load would build a deemer balance, which would not (under a new exchange contract containing similar deemer account provisions) be a cash obligation to the utility and its consumers. *Id.* As discussed in BPA's direct testimony, an in-lieu for less than 100 percent could lead to anomalous and undesirable results unless the utility is allowed to terminate any in-lieued load when the in-lieu cost is less than the PF Exchange rate. *Id.*; Boling and Doubleday, WP-02-E-BPA-30, at 15-16. As discussed earlier, a decision by the Administrator to in-lieu 50 percent of a utility's exchange load might be based in part on spreading some level of Federal power benefits to exchanging utilities. Boling and Doubleday, WP-02-E-BPA-53, at 7. Without an option to terminate its in-lieued exchange load, a utility with some actively exchanging load could find itself in the perverse situation of receiving zero, or even negative, overall benefits. *Id.*

The DSIs argue that BPA missed the import of the DSI proposal. DSI Brief, WP-02-B-DS-01, at 68. The DSIs argue that BPA's initially proposed PF Exchange rate was higher than it should have been and that ASCs were overstated. *Id.* The DSIs argue that BPA has overstated the in-lieu purchase cost with inappropriate transmission costs. *Id.* The DSIs argue that if ASCs, the PF Exchange rate, and in-lieu purchase costs had been calculated as the DSIs suggested, larger exchange benefits would have been provided to the in-lieued utilities than BPA is offering them. *Id.* The DSIs argue that BPA's conclusion that an in-lieu transaction was of no value to the utility is an artifact of errors in BPA's analysis that artificially raised the PF Exchange rate above the market price of power. *Id.* The DSIs' claims regarding BPA's proposed PF Exchange rate were based primarily on arguments relating to the section 7(b)(2) rate test. BPA agreed and disagreed with particular DSI arguments in this area; these arguments are addressed in detail in ROD chapter 12. The DSIs' claims that BPA's forecasted ASCs were overstated were addressed previously in this section. The DSIs' argument that BPA has overstated the in-lieu purchase cost with inappropriate transmission costs was addressed in part in this section, and another variation of the DSIs' argument will be addressed in Issue 4, *infra*. While the DSIs argue that BPA's conclusion that an in-lieu transaction was of no value to the utility is an artifact of errors in BPA's analysis that artificially raised the PF Exchange rate above the market price of power, BPA, as discussed in greater detail elsewhere in this section of the ROD, believes that its analyses and conclusions were correct. With the PF Exchange rate properly determined to be above the market price of power, BPA has correctly concluded that exchanging utilities would have no rational incentive to purchase in-lieu power from BPA at a rate greater than market prices. Boling and Doubleday, WP-02-E-BPA-30, at 15.

The DSIs argue that the purpose of the in-lieu provision of section 5(c) of the Northwest Power Act is to limit the cost of the REP. DSI Ex. Brief, WP-02-R-DS-01, at 23-24. The DSIs argue that because BPA is required to recover its total costs, limiting the cost of the REP is for the benefit of BPA's non-exchanging customers. *Id*. The DSIs argue that it is therefore inappropriate for BPA to determine the amount of in-lieu transactions based on the goal of providing exchanging utilities additional, non-statutory benefits at the expense of non-exchanging customers. *Id*. While the purpose of the in-lieu provision is to control REP costs, this does not mean that BPA is required to use in-lieu transaction to reduce REP costs as much as possible. As the Northwest Power Act recognizes, "the Administrator *may* acquire an equivalent amount of electric power from other sources . . . ." 16 U.S.C. §839c(c)(5). BPA is therefore not required to conduct in-lieu transactions to the fullest extent possible. Boling and Doubleday, WP-02-E-BPA-30, at 10. While conducting extensive in-lieu transactions would benefit non-exchanging customers, it would severely harm the residential and small farm consumers of exchanging utilities, for whom the REP is their primary form of access to the benefits of the Federal power system. BPA has no "goal of providing exchanging utilities additional *non-statutory* benefits" at the expense of others. Failure to in-lieu the entire load of an exchanging utility simply allows exchanging utilities to receive exchange benefits as provided in the Northwest Power Act, consistent with BPA's proposed in-lieu transactions. Boling and Doubleday, WP-02-E-BPA-53, at 16. As noted in greater detail above, there are numerous reasons for limiting in-lieu transactions.

The DSIs contend that BPA erred in concluding that in-lieu transactions are appropriate only for utilities with ASCs that exceed the PF Exchange rate. DSI Ex. Brief, WP-02-R-DS-01, at 24. The DSIs note that the PF Exchange rate is the price for BPA's sale side of the exchange, and the ASCs and in-lieu price are alternative prices for the purchase side of the transaction. *Id*. The DSIs argue that an in-lieu transaction must be judged only by whether an exchanging utility's ASC exceeds the cost of the in-lieu alternative. *Id.* This argument is not persuasive. If a utility's ASC is below the PF Exchange rate, the utility is not receiving any benefits from BPA under the REP. Boling and Doubleday, WP-02-E-BPA-30, at 3. BPA is therefore not incurring costs for that utility's participation in the REP. Because of this, and for the reasons noted previously, there is no need to in-lieu the utility.

Decision

BPA properly forecasted in-lieu transactions for 50 percent of residential exchange load. BPA properly forecasted that exchanging utilities would not purchase power from BPA in an in-lieu transaction, because such purchases would be uneconomic.

Issue 4

Whether BPA properly included certain transmission costs in the forecasted cost of in-lieu purchases.

Parties' Positions

The DSIs argue that BPA improperly included certain transmission costs in the forecasted cost of in-lieu purchases. DSI Brief, WP-02-B-DS-01, at 67; DSI Ex. Brief, WP-02-R-DS-01, at 2-67.

BPA's Position

BPA has properly included transmission costs in the forecasted cost of in-lieu purchases. Boling and Doubleday, WP-02-E-BPA-53, at 2-7.

Evaluation of Positions

The DSIs argue that BPA improperly included certain transmission costs in the forecasted cost of in-lieu purchases. DSI Brief, WP-02-B-DS-01, at 67. The Joint DSIs argued that a determination to in-lieu compares an IOU's ASC to the cost of purchasing power delivered to the BPA system. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 9-10. Because the block purchase price is a price for energy delivered to BPA's system, the Joint DSIs argued that adding additional transmission costs is wrong. *Id*. BPA disagrees. BPA has the authority to conduct an in-lieu transaction if the cost of the in-lieu acquisition (*i.e.*, the combined cost of the resource and delivery of that resource to BPA's system) is less than the cost of purchasing the electric power offered by the exchanging utility at the utility's ASC. 16 U.S.C. §839c(c)(5). However, it does not follow that BPA's PBL would always exercise its discretion to conduct an in-lieu transaction in all such circumstances. Boling and Doubleday, WP-02-E-BPA-53, at 2. Such a determination would be based on consideration of the economic viability of the entire transaction, taking into account all transaction costs and other factors. *Id.* For example, in order to accomplish the power delivery to the exchanging utility required by the in-lieu transaction, the PBL might find it necessary to purchase transmission services from the TBL that would not be required in the absence of an in-lieu transaction. *Id.* If the PBL incurs such costs, they will be included in the assessment of whether to conduct an in-lieu transaction. *Id.* If such costs make the in-lieu transaction more expensive, in the aggregate, than the traditional exchange, then BPA would not exercise its ability to in-lieu. *Id.*

In summary, an in-lieu transaction is authorized and will be considered based on an initial comparison between ASC and the cost of the in-lieu resource delivered to BPA's system. *Id.* At this stage, an assessment of the economic viability of the transaction based on total transaction costs will be used to determine whether conducting the in-lieu transaction would be prudent. *Id.* at 2-3. While the DSIs are correct that the block purchase price is a price for energy delivered to BPA's system, this is not the end of the question, because the PBL must determine if there are additional costs that must be considered. *Id.* at 3.

The Joint DSIs argued that the cost to deliver the power to PBL's customer in an in-lieu transaction will be paid by the customer in transmission charges paid to the TBL. Schoenbeck *et al.,* WP-02-E-DS/AL/VN-04(E1), at 9. This argument is incorrect. The customer will not pay the TBL for transmission. Boling and Doubleday, WP-02-E-BPA-53, at 3. The PBL will purchase transmission, most probably from the TBL, and the PF Exchange Program rate revenues will reimburse the PBL for its transmission expenses. *Id.* The PF Exchange Program rate is a bundled rate with transmission included. *Id.*

The Joint DSIs argued that deliveries of in-lieu power do not have to be at the same point of receipt on the BPA system as deliveries of the exchange purchase, because the transmission paid by the load moves the power from the BPA system point of receipt to the utility's point of delivery. Schoenbeck *et al.,* WP-02-E-DS/AL/VN-04(E1), at 9. Therefore, the additional transmission adder is not needed for the in-lieu purchase. *Id.* BPA agrees that deliveries of in-lieu power to BPA do not have to be at the same point of receipt on the BPA system as deliveries of the exchange purchase. Boling and Doubleday, WP-02-E-BPA-53, at 3. As discussed above, however, BPA power must be delivered to a utility's point or points of delivery in an in-lieu transaction. *Id.* Regarding the "additional transmission adder," the Joint DSIs apparently believe that the utility pays the transmission provider for the transmission from BPA's system to the utility's point of delivery, so transmission costs should not be included in the in-lieu resource cost determination. *Id.* However, the load does not pay directly for transmission. *Id.* In the case of an in-lieu transaction, the PF Exchange Program rate paid by the exchanging utility includes transmission costs. *Id.* This transmission portion of the PF Exchange Program rate reimburses the PBL for the costs of transmission it pays to the transmission provider. *Id.* The load pays for transmission through the PF Exchange Program rate, but these revenues go to the PBL. *Id.* at 3-4. From the PBL's point of view, in-lieu related transmission of BPA power is both a cost, which it pays to the TBL, and a revenue, which it recovers by way of the PF Exchange Program rate. *Id.* at 4.

The Joint DSIs argued that the transmission costs for in-lieu power are already properly recognized as a part of the PF Exchange rate. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 9. The Joint DSIs stated that on the purchase side, BPA costs power where it comes to the system, and on the sale side, BPA adds transmission costs to get the power across the system to the delivery point. *Id.* The Joint DSIs argued that for BPA to add transmission to the in-lieu purchase price is double-counting the transmission charges, because the transmission is already charged on the sales side. *Id*. This argument is incorrect. When determining whether an in-lieu transaction is financially prudent, the PBL must consider the total cost of the in-lieu transaction it will face. Boling and Doubleday, WP-02-E-BPA-53, at 4. Where an in-lieu purchase is delivered to BPA's system, such total in-lieu transaction costs include the cost of acquiring the in-lieu resource, the cost of transmission to get the power to BPA's system, and the cost to wheel BPA power to the utility's point of delivery. *Id.* Only if the PBL's total costs of the in-lieu transaction, including all transmission costs, are less than the exchange transaction costs (*i.e.*, the utility's ASC) would the in-lieu transaction be financially prudent. *Id.* On the in-lieu transaction revenue side, the customer is charged the PF Exchange Program rate, which includes a transmission charge. *Id.* This is not double-counting the transmission costs. *Id.* From the PBL's point of view, the in-lieu transaction has a cost of transmission component and an offsetting transmission revenue component. *Id.* These two transmission components are not added together, they cancel each other out. *Id.* Therefore, there is no double-counting. *Id.*

The Joint DSIs argued that BPA should use the in-lieu purchase price without transmission costs to compare with the utility's ASC when determining if an in-lieu transaction is indicated. Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E1), at 10. As discussed above, however, in-lieu transaction costs must include any costs of wheeling BPA power to the point or points of delivery. Boling and Doubleday, WP-02-E-BPA-53, at 5. The PBL must consider the full cost of the in-lieu transaction, not just the cost of getting in-lieu power to BPA's system. *Id.* If the Joint DSIs' recommendation were followed, the PBL could enter into an in-lieu transaction that would be more costly than the associated exchange transaction. *Id.* For example, consider a situation where a utility's ASC is $39/MWh, the PF Exchange Program rate is $37/MWh, the cost of the in-lieu resource delivered to BPA's system is $36/MWh, and TBL transmission from BPA's system to the utility's point of delivery is $4/MWh. *Id.* Traditional exchange benefits, a net cost to the PBL, would be $2/MWh ($39 minus $37), with the utility's ASC representing a fixed total transaction cost. *Id.* Using the Joint DSI method, the PBL would compare the cost of the in-lieu resource delivered to BPA's system of $36/MWh with the utility's ASC of $39/MWh and determine that the in-lieu transaction should occur. *Id.* However, this method fails to account for the additional costs associated with the in-lieu transaction. *Id.* These costs include the $4/MWh associated with the PBL's purchase of TBL transmission from BPA's system to the utility's point of delivery. *Id.* This additional cost is made necessary by the fact that an in-lieu transaction, unlike the traditional exchange transaction, requires that BPA actually deliver power to the exchanging utility's point of delivery. *Id.* For this reason, the correct method is to compare the $40/MWh ($36 plus $4) total in-lieu transaction cost with the utility's ASC of $39/MWh. *Id.* In this situation, an in-lieu transaction would cost the PBL a total transaction cost of $3/MWh ($40 minus $37), $1/MWh more than the $2/MWh traditional exchange payment calculated above. *Id.*

The DSIs argue that BPA improperly added an extra transmission cost to the in-lieu transaction. DSI Brief, WP-02-B-DS-01, at 67. BPA disagrees. In rebuttal testimony, BPA established that the total in-lieu transaction cost, the total cost the PBL must consider when determining if an in-lieu transaction is financially prudent, includes two types of transmission costs. Boling and Doubleday, WP-02-E-BPA-53, at 2-5. Where an in-lieu purchase is delivered to BPA's system, such total in-lieu transaction costs include the cost of acquiring the in-lieu resource, the cost of transmission to get the power to BPA's system, and the transmission cost to wheel BPA power to the utility's point of delivery. *Id.*

The DSIs note BPA's claim that there is an "extra transmission cost" to the PBL in an in-lieu transaction, because the PBL would have to make actual transmission payments to the TBL for wheeling power sold to a utility in an in-lieu transaction. DSI Brief, WP-02-B-DS-01, at 67. BPA disagrees with the DSIs' characterization that the cost of wheeling BPA's system power to the utility's point of delivery during an in-lieu sale is an "extra transmission cost." The Joint DSIs first showed their misunderstanding of the in-lieu power sale process in their direct testimony, where they stated that "[t]he cost to deliver the power to BPA's customers will be paid by the customers in transmission charges paid to the TBL." Schoenbeck *et al.*, WP-02-E-DS/AL/VN-04(E-1), at 9. The Joint DSIs went on to accuse BPA of double-counting the transmission charges on the power side, because the transmission is already charged on the sales side. *Id.* at 10. The Joint DSIs apparently believe that the utility pays the transmission provider for the transmission from BPA's system to the utility's point of delivery, so transmission costs should not be included in the in-lieu resource cost determination. Boling and Doubleday, WP-02-E-BPA-53, at 3-4. However, the load does not pay directly for transmission. *Id.* In the case of an in-lieu transaction, the PF Exchange Program rate paid by the exchanging utility includes transmission costs. *Id.* This transmission portion of the PF Exchange Program rate reimburses the PBL for the costs of transmission it pays to the transmission provider. *Id.* The load pays for transmission through the PF Exchange Program rate, but these revenues go to the PBL. *Id.* From the PBL's point of view, in-lieu related transmission of BPA power is both a cost, which it pays to the TBL, and a revenue, which it recovers by way of the PF Exchange Program rate. *Id.*

The DSIs argue that Northwest Power Act sections 5(c) and 7(b) require that, for ratesetting purposes, BPA must treat the REP as if it were a purchase and sale of power, yet BPA modeled the Residential Exchange different than a purchase and sale. DSI Brief, WP-02-B-DS-01, at 67. BPA disagrees. For ratemaking purposes, BPA's rates models treat the REP as if it were a purchase and sale of power. The purchase of power under the REP is represented by the gross costs of the purchased Residential Exchange resources shown in the RAM Cost of Service Analysis (COSA) tables. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-53, line 18. The allocation of the purchased power from the residential exchange resources to customer class loads is shown in the EAF tables. *Id.* at 47-48. The sale of power under the REP is shown in Table RDS36 in the RAM. *Id.* at 77. BPA has always modeled the REP as a purchase and sale of power, and is doing so in this rate case. After the rates models determine the level of the PF Exchange Program rate, that rate is used in the implementation of the REP to determine the actual exchange benefits.

The DSIs argue that for a real exchange (*i.e.*, purchase and sale), BPA staff treated the cost of wheeling power sold to the exchange customer as a real cost for which the PBL would have to pay the TBL. DSI Brief, WP-02-B-DS-01, at 67. Tr. 1672-73. The DSIs argue that for the Residential Exchange, on the other hand, BPA staff modeled the sale half of the transaction as if the PBL keeps that portion of the PF Exchange rate associated with the cost of wheeling power to the exchanging utility. DSI Brief, WP-02-B-DS-01, at 67. Tr. 1673-74. The DSIs imply that this treatment of the cost of wheeling power is inconsistent with BPA staff's understanding that the residential exchange was treated as an actual exchange of power. First, BPA disagrees with the DSIs use of the term "real exchange." Outside of the ratemaking process and absent an in-lieu sale of real power to an exchanging utility, the implementation of the REP does not comprise a "real" sale of power to the exchange customers. Boling and Doubleday, WP-02-E-BPA-30, at 2. A "real" sale of BPA system power to the IOUs could take the form of an in-lieu sale or a sale under the NR or FPS rate schedules. But in none of these cases would there be a balancing "exchange purchase" from the IOUs. Also, the DSIs have misrepresented BPA's cross-examination testimony. Tr. 1672-72. BPA's witness was not discussing a "real exchange," as the DSIs contend. The transcript quoted below shows clearly that BPA's witness was originally answering questions concerning a hypothetical sale of real BPA system power and was careful to identify the point at which the DSI attorney started discussing an exchange transaction with an exchange customer.

> Q. In an actual power sale where you agree through your contract to provide delivery to a utility's system, you would incur the generation costs we just talked about and some transmission expenses, am I correct?
>
> A. (Mr. Doubleday) Yes.
>
> Q. And those transmission expenses would be a real expense you would have to pay money to the TBL, am I correct?
>
> A. (Mr. Doubleday) Yes. The PBL would have--the PBL would have an expense due to services provided by the TBL.
>
> Q. So the net to the PBL, exclusive of the pass-through of the transmission expenses to the TBL, would be the cost of generation, am I correct?
>
> A. (Mr. Doubleday) It would be--yes, as represented by the undelivered rate, I guess.
>
> Q. And when you model the sales side, the BPA sales side, of the exchange transaction, do you model a transmission expense in which you turn the proceeds from the transmission component of the sale over to the TBL?
>
> A. (Mr. Doubleday) Just to be clear, this is modeling the exchange once again?
>
> Q. Yes.
>
> A. (Mr Doubleday) We are away from the true and actual sale?
>
> Q. Right.
>
> A. (Mr Doubleday) No, we do not--we do not assume that monies will be sent to the TBL.

Tr. 1672-73. In cross-examination, BPA's witness was careful to distinguish between an actual sale of BPA system power and the traditional REP. In the actual sale of power, the TBL would provide a service and receive revenues. Tr. 1672-74. In the implementation of the traditional REP, the TBL does not provide a service and does not receive revenues. *Id.*

The DSIs argue that this treatment of the cost of wheeling power to the exchanging utility is contrary to BPA staff's understanding that the residential exchange was supposed to be treated as an actual exchange of power. DSI Brief, WP-02-B-DS-01, at 67. Tr. 1667. The DSIs have misrepresented BPA's cross-examination testimony. The BPA witness testified that for ratemaking purposes, BPA models the REP as an actual exchange of power. Tr. 1667. The DSIs are confusing the treatment of transmission costs and revenues under three separate situations: an actual sale of BPA system power, the actual implementation of the REP, and REP ratemaking and modeling assumptions. In an actual sale of BPA system power, the TBL would provide wheeling services and would receive revenues. Tr. 1672. As stated above, for ratemaking purposes, which include the determination of the level of the PF Exchange Program rate, the REP is modeled as an actual purchase and sale, complete with wheeling costs. However, under the normal implementation of the REP, which uses the PF Exchange Program rate calculated in the rates models to determine exchange benefits, no actual power is transferred either to or from BPA. The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA at the utility's ASC and the less expensive power "sold" to the participating utility at BPA's PF Exchange Program rate. Boling and Doubleday, WP-02-E-BPA-30, at 2. The utility's ASC and BPA's PF Exchange Program rate are assumed to have similar components, including generation costs and wheeling costs, so as to make their comparison viable. Tr. 1667. The TBL would not receive revenues under the normal implementation of the REP, because the PBL is responsible for all costs and would, therefore, receive all revenues. Tr. 1674-75.

The DSIs argue that BPA's demonstration of its claim that it does not model the REP inconsistent with an actual purchase and sale is nothing more than a description of its inconsistencies. DSI Ex. Brief, WP-02-R-DS-01, at 24, citing Draft ROD, WP-02-A-01, at 11-19 to 11-20. BPA disagrees with the DSI argument that BPA has modeled the REP different than a purchase and sale. As discussed above, for ratemaking purposes, BPA's rates models treat the REP as if it were a purchase and sale of power. The *purchase of power under the REP* is modeled by the gross costs of the purchased Residential Exchange resources shown in the RAM COSA tables. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 49-53, line 18. The allocation of the purchased power from the Residential Exchange resources to serve customer class loads is shown in the EAF tables. *Id.* at 47-48. The Rate Design Step of the RAM allocates the costs associated with the purchase of the REP resources in the COSA_11 table. *Id.* at 56. The *sale of power under the REP* is modeled in Table RDS36 in the RAM. *Id.* at 77. BPA has always modeled the REP as a purchase and sale of power, and is doing so in this rate case. After the rates models determine the level of the PF Exchange Program rate, that rate is used in the implementation of the REP to determine the actual exchange benefits.

The DSIs argue that BPA admits that it models the REP as if the PBL retains the revenues from the sale of TBL transmission services, in contrast to paying those revenues over to the TBL as would occur in a actual power sale transaction. DSI Ex. Brief, WP-02-R-DS-01, at 24, citing Draft ROD, WP-02-A-01, at 11-19 to 11-20. The DSIs have misrepresented BPA's position. Nowhere in the cited material does BPA say that the REP is modeled as if the PBL retains the revenues from the sale of TBL transmission services in contrast to paying those revenues over to the TBL as would occur in a actual power sale transaction. The ratemaking modeling of the REP assumes a real power sale and assumes that the TBL will provide a service for which it would get revenues. However, no real revenues are actually distributed to the TBL under the traditional implementation of the REP. Tr. 1667. Under the actual "paper transaction" implementation of the REP, no real power is sold, and the TBL provides no service for which it would get revenues. Once again, the DSIs are confusing the treatment of transmission costs and revenues under three separate situations: an actual sale of BPA system power, the actual implementation of the REP, and REP ratemaking and modeling assumptions. In an actual sale of BPA system power, the TBL would provide wheeling services and would receive revenues. Tr. 1672. As stated above, for ratemaking purposes, which include the determination of the level of the PF Exchange Program rate, the REP is modeled as an actual purchase and sale, complete with wheeling costs. However, under the normal implementation of the REP, which uses the PF Exchange Program rate calculated in the rates models to determine exchange benefits, no actual power is transferred either to or from BPA. The "exchange" has been referred to as a "paper" transaction, where BPA provides the participating utility cash payments that represent the difference between the power "purchased" by BPA at the utility's ASC and the less expensive power "sold" to the participating utility at BPA's PF Exchange Program rate. Boling and Doubleday, WP-02-E-BPA-30, at 2. The utility's ASC and BPA's PF Exchange Program rate are assumed to have similar components, including generation costs and wheeling costs, so as to make their comparison viable. Tr. 1667. The TBL would not receive revenues under the normal implementation of the REP, because the PBL is responsible for all costs and would, therefore, receive all revenues. Tr. 1674-75.

The DSIs argue that there is no basis for claiming that under the statutory exchange "the PBL is responsible for all costs." DSI Ex. Brief, WP-02-R-DS-01, at 24, citing Draft ROD, WP-02-A-01, at 11-19 to 11-20. In summary, the DSIs argue that BPA has modeled the REP different than a purchase and sale. *Id*. at 24-25. As discussed above, under the normal "paper transaction" implementation of the REP, no real power is sold, and the TBL provides no service for which it would receive revenues. The cash payments associated with the traditional implementation of the REP are a power cost to be recovered from PBL's rates. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, at 99, line 24. As discussed and documented at length above, the ratemaking modeling of the Rate Design Step of the RAM clearly models the REP as a purchase of resources capable of serving load and a sale of power at the PF Exchange Program rate.

The DSIs argue that this alleged modeling inconsistency exaggerates the apparent cost of in-lieu transactions and distorts the choice to in-lieu or not in-lieu. DSI Brief, WP-02-B-DS-01, at 67. BPA has shown, as demonstrated by the foregoing discussion that, contrary to the DSIs' contention, there are no modeling inconsistencies.

Decision

BPA properly included transmission costs in the forecasted cost of in-lieu purchases.

Issue 5

Whether BPA properly developed the 1984 ASC Methodology and whether BPA should revise exchanging utilities' deemer balances.

Parties' Positions

The IOUs argue that BPA should overhaul the ASC Methodology and utilities' deemer balances to restore congressionally intended outcomes for residential consumers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47-48; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 37-38. PPC argues that the 1984 ASC Methodology was properly developed and has withstood the test of time. PPC Brief, WP-02-B-PP-01, at 67-68.

BPA's Position

BPA properly developed the 1984 ASC Methodology. Issues regarding deemer balances are not determined in a section 7(i) hearing. Boling and Doubleday, WP-02-E-BPA-53, at 15. Deemer balances are contract issues that must be addressed by BPA and exchanging utilities in implementing the RPSAs. *Id.*

Evaluation of Positions

The IOUs argue that BPA has not fairly administered the REP to produce an equitable result for the residential customers of regional IOUs. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 37. The IOUs note that BPA revised the ASC Methodology in 1984 to remove income taxes and return on equity from the calculation, resulting in a reduction in the amount of benefits under the REP. *Id.* Contrary to the IOUs' claims, BPA properly revised the ASC Methodology in 1984, both procedurally and substantively. The 1984 ASC Methodology was reviewed and approved by FERC. *See* Order No. 400, "Final Rule," 49 Fed. Reg. 39,293 (1984) and Order No. 400-A, 50 Fed. Reg. 4,970 (1985). The 1984 ASC Methodology was also affirmed by the United States Court of Appeals for the Ninth Circuit. *PacifiCorp v. FERC*, 795 F 2d 816 (9th Cir. 1986). The IOUs argue that while the 1984 ASC Methodology was upheld by the United States Court of Appeals for the Ninth Circuit, the court did not sanction the permanent implementation of the revised methodology. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 48. The court, however, also noted that the Northwest Power Act did not proscribe BPA's adjustments to the ASC Methodology. *See PacifiCorp*, 795 F.2d at 823. Furthermore, BPA has not stated that the current ASC Methodology is permanent. As noted below, BPA recognizes that the ASC methodology can be revised. The timing and substance of such a revision, however, are not determined in a section 7(i) proceeding to establish BPA's wholesale power rates. The IOUs also argue that there is no longer a need or justification for the exclusion of taxes and return on equity from current ASC calculations. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 48. Again, these are substantive ASC Methodology issues that can be addressed only in a separate proceeding to develop a new ASC Methodology. 16 U.S.C. §839c(c)(7). These issues cannot be resolved in a ratemaking proceeding under section 7(i) of the Northwest Power Act. 16 U.S.C. §839e(i).

The IOUs argue that BPA has recognized that the ASC Methodology can be revised. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47. The IOUs also argue that BPA has recognized that if the ASC Methodology is revised, forecasted exchange benefits would increase significantly. *Id.* This argument mischaracterizes BPA's testimony. BPA noted that if the ASC Methodology were revised *in the manner in which the IOUs would like to revise it*, exchange benefits would increase. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 37. *See* Boling and Doubleday, WP-02-E-BPA-30, at 3-4. BPA did not state that any revision to the ASC Methodology would increase exchange benefits. *Id.* The effects of a change in the ASC Methodology cannot be known until a new methodology is established. A revised ASC Methodology could either increase or decrease exchange benefits.

The IOUs argue that BPA should, in a separate proceeding, revise the ASC Methodology and adjust deemer balances to reflect that corrected methodology. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 3, 13, 37-38. The ASC Methodology is not established in a section 7(i) hearing but instead, as the IOUs correctly acknowledge, in a separate administrative proceeding. 16 U.S.C. §839c(7); Boling and Doubleday, WP-02-E-BPA-53, at 15. Any decision by BPA to revise the ASC Methodology will be made in a separate forum. Boling and Doubleday, WP-02-E-BPA-53, at 15.

The IOUs also argue that it is within BPA's discretion to adjust deemer balances that have the effect of eliminating the exchange for many customers. IOU Brief, WP-02-B-AC/GE/IP/MP/PL/PS-01, at 47; IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 38. The IOUs argue that the 1984 ASC Methodology not only reduced exchange benefits but had a significant impact on deemer accounts of some utilities. *Id.* at 48. The IOUs argue that currently calculated deemer balances are not the result of comparing a utility's ASC under the 1981 RPSA with BPA's PF Exchange rate, but are a result of comparing a utility's ASC under the 1984 ASC Methodology with BPA's PF Exchange rate. *Id.* The IOUs argue that the deemer balance should therefore not be carried over to new RPSAs. *Id.* However, ASC benefits and deemer balances are calculated by comparing a utility's ASC as established under the then-current ASC Methodology and the then-current PF Exchange rate. As noted above, BPA's 1984 ASC Methodology was approved by FERC and the Ninth Circuit. ASCs and deemer balances would thus be properly based on the comparison between a utility's ASC under the 1984 ASC Methodology and the then-current PF Exchange rate.

The IOUs argue that when utilities agreed in 1981 that deemer balances would be carried over to the next contract, they did not contemplate that BPA would make a unilateral change in the ASC Methodology and would permanently eliminate benefits. *Id.* This argument contains a number of mischaracterizations. First, the 1981 ASC Methodology, an exhibit to the RPSA, expressly provided that it could be revised. Parties therefore could easily envision that the 1981 Methodology might be revised at a later time. Also, BPA did not simply make a unilateral change in the 1981 ASC Methodology. BPA revised the ASC Methodology only after conducting an extensive administrative proceeding with regional parties as required by law. 16 U.S.C. §839c(c)(7). Furthermore, the 1984 ASC Methodology, like any ASC Methodology, does not permanently eliminate or increase exchange benefits. Because the ASC Methodology can be revised, benefits under a new methodology might be increased or decreased. The IOUs disagree with BPA's assertion that the IOUs mischaracterized BPA's change in the ASC Methodology as being "unilateral." IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 38. The IOUs state that BPA cannot address the customers' intent. *Id.* BPA, however, makes no attempt to evaluate the IOU customers' intent. The development of the methodology speaks for itself. BPA's 1984 ASC Methodology ROD, BPA File No. ASC-83, recounts the process used to develop a new ASC Methodology. The ROD lists the initiation of the consultation process by publishing a "Request for Recommendations" in the Federal Register, 48 Fed. Reg. 45,829 (1983). After reviewing comments received in response to the notice, BPA published a "Proposed Methodology for Determining the Average System Cost of Resources for Electric Utilities Participating in the Residential Exchange." 49 Fed. Reg. 4,230 (1984). This proposal solicited both comments and reply comments from interested parties. *Id*. Extensive written comments were filed by interested parties. By letter dated February 17, 1984, BPA announced that public meetings would be held in Spokane and Seattle, Washington; Portland, Oregon; and Idaho Falls, Idaho, to clarify technical aspects of the proposed methodology. *Id*. On March 2, 1984, BPA announced by letter that it would be holding a transcribed public meeting on April 20, 1984, to discuss all issues relating to the BPA proposal, initial comments, reply comments, and possible settlement of any issue. *Id*. The letter also noted that additional meetings would be scheduled with the Regional Council and state regulatory commissions and that BPA would consider requests for meetings with smaller groups of parties. *Id*. Additional public meetings were held between April 23 and 27, 1984. *Id*. Additional transcribed negotiating sessions were held between April 30 and May 4, 1984. *Id*. On April 30, 1984, BPA heard extensive oral argument by all interested parties. *Id*. On May 15, 1984, after reviewing the voluminous record, BPA staff released a proposed ASC Methodology. *Id*. Additional comments were taken on the proposed methodology. *Id*. BPA issued the final ASC Methodology on June 4, 1984. In summary, one can hardly characterize the development of the ASC Methodology as a unilateral decision. Furthermore, as discussed above, it is readily apparent that the ASC Methodology can be changed and, if changed, can affect exchange benefits. Finally, with regard to deemer balances, such issues are not determined in a section 7(i) hearing. Boling and Doubleday, WP-02-E-BPA-53, at 15. Deemer balances are contract issues that must be addressed by BPA and exchanging utilities in implementing the RPSAs. *Id.*

The IOUs state that BPA has offered no reasoning in the Draft ROD as to why changing the ASC Methodology and adjusting deemer balances could not be made *concurrently* with the rate proceeding in order to produce the level of exchange benefits supported by the IOUs. IOU Ex. Brief, WP-02-R-AC/GE/IP/MP/PL/PS/EN-01, at 38. By taking this position, the IOUs are in clear agreement with BPA's position that revising the ASC Methodology must be done in a different forum, and that deemer balances are contract issues not determined in a section 7(i) hearing. BPA, however, is not required to revisit the ASC Methodology at any specific time. As is clear from references to other proceedings mentioned in the record, the period during which the rate case has been conducted has been full of BPA activities. As all parties familiar with the development of a new ASC Methodology must recognize, an ASC Methodology consultation proceeding is a tremendously demanding, time-consuming undertaking. At the same time as BPA's rate case, BPA and regional parties have been working on the development of preference customer, DSI, and IOU power sales contracts; development of RPSAs; development of the proposed Residential Exchange settlement agreements with regional IOUs; public comments on whether to increase the amount of the proposed IOU settlements by 100 aMW and the proposed allocations of settlement benefits among the IOUs; development of the Power Subscription Strategy Administrator's Supplemental ROD; and so on. It would have been an administrative nightmare from both BPA's and the parties' perspectives to conduct an ASC Methodology consultation proceeding at the same time as BPA's rate case. Furthermore, even if done concurrently, the results of the new ASC Methodology and deemer balances would not have been available in time to be used in the rate case.

Decision

BPA properly developed the 1984 ASC Methodology. Issues regarding whether the 1984 ASC Methodology should be revised and, if so, in what manner, must be addressed in a separate administrative proceeding and will not be resolved here. Similarly, issues regarding deemer balances must also be addressed in a separate forum and will not be resolved here.