Should the Administrator include transmission costs in each investor-owned utility's (IOUs) average system costs (ASC) when determining the exchange benefits owed to the utility under § 5(c) of the Act?

Yes. The Administrator addressed this issue in his 1984 Record of Decision (ROD) regarding the Average System Cost Methodology. He concluded that each IOU's ASC should include transmission costs that "reflect integration of generating resources."[1] The Administrator should continue this treatment of transmission costs for the same policy reasons articulated by the IOUs in the 1984 ASCM proceeding, as well as for an additional policy reason articulated at the ongoing workshops regarding the Residential Exchange Program. Oregon has a resource portfolio standard that requires utilities to acquire renewable resources, such as wind. Wind generation has typically been sited in remote areas in Oregon, and this will likely continue. Omitting the costs to transmit energy generated by renewable resources to a utility's load center would significantly undervalue the cost of renewable resources.

At least one participant to the workshops for the Residential Exchange Program has asserted that the Administrator should exclude transmission costs from IOUs' ASC because transmission does not fall within the definition of "resource." The Administrator rejected this legal argument in 1984, and the BPA staff should do so now.

In 1984, the Administrator concluded that inclusion of transmission costs in the calculation of an IOU's ASC is permitted by the Act, but not required, rejecting the argument that the Act's definition of "resource" required exclusion of the costs. The Administrator's decision is supported by the Ninth Circuit Court of Appeals opinion in *PacifiCorp v. FERC*.[2] In that case, IOUs argued the Administrator erred in excluding the IOUs' cost of equity and income taxes from the ASC calculation. The Court disagreed, noting that the Act "neither commands nor proscribes [such] adjustments in ASC methodology." The same is true of transmission costs. Whether to include the costs is one of policy, not law. Accordingly, BPA staff should reject any argument that the Act *requires* the exclusion of transmission costs from the IOUs' ASC.[3]

Should the Administrator include a utility's equity costs in each IOU's ASC when determining the exchange benefits owed to the utility under § 5(c) of the Act?

Yes. The Administrator excluded these costs in his 1984 ASCM ROD. The policy reasons underlying this decision were wrongly decided or no longer exist.

As a preliminary matter, OPUC notes that whether to include the IOUs' cost of equity (COE) in the IOUs' ASC is a policy question, not a legal one. The Ninth Circuit Court of

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[1] Average System Cost Methodology ROD at 42.
[2] 795 F.2d 816 (1986).
[3] The PUC notes that (definition of resource is narrow).

Appeals addressed this specific question in *PacifiCorp v. FERC*, and concluded that the Administrator has discretion to include, or exclude, the costs.[4]

The Administrator's 1984 decision to exclude the IOUs' COE from their ASC has the following underpinnings: (1) at least one commission within the region appeared to have artificially inflated an IOUs' COE to allow the utilities to recover for retired plant, and have that recovery included in the utilities' ASC; (2) even if an IOU's COE was not artificially inflated to allow for specific recovery of terminated plant, and was based on comparisons to COEs allowed around the nation, the COE will include costs of terminated plant; (3) COE is not a true resource cost within the limits of § 5(c)(7)(c); and (4) excluding COE is necessary to prevent BPA from becoming a "deep pocket" to which exchanging utilities can shift excessive or improper costs.[5]

The first reason underlying the Administrator's 1984 decision no longer exists. In 1984, Oregon utilities were regulated by a one-person regulatory body. Oregon addressed the Commissioner's actions regarding the utilities' COEs, and others, by creating a three-person Public Utility Commission. Further, regulatory commissions now use extensive integrated least cost planning investigations, with significant public involvement such that generation plant "dry holes" are unlikely to occur. Accordingly, the situation that gave rise to the concern of overstating COE to compensate for dry holes is unlikely to repeat itself.

The second underpinning, that any return on equity, even one based on comparisons to other returns on equity allowed in other parts of the country, will include recovery for terminated plant, is not reasonably addressed by artificially lowering the IOUs' COE to their embedded cost of debt for purposes of determining their ASC. In fact, the Ninth Circuit Court of Appeals made a similar observation in its 1986 opinion, noting "[p]etitioners correctly observe that there is no logical congruence which would support making interest on debt a proxy for equity return."[6] Instead, the reasonable solution to this concern is to establish a FERC cost of equity benchmark as an upper bound on the IOUs COE.[7]

The third underpinning, that cost of equity is not truly a resource cost, is simply wrong. In support of this conclusion, the Administrator stated that equity costs are related to "default risk," and that BPA effectively eliminates default risk by guaranteeing the return

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[4] *Id.*, 795 F.2d at 821-22.
[5] Average System Cost Methodology ROD at 53-55.
[6] 795 F.2d at 823.
[7] In fact, the BPA staff originally made a comparable proposal in the 1984 proceeding. BPA staff recommended that the Administrator use a generic method for determining each IOU's equity return component of ASC, based on national averages for IOUs, and then adjust that number downward by 100 basis points to account for region-specific circumstances.

on investment for residential and small farm loads.[8] The last 20-odd years of experience has shown that this is not the case – the REP benefits do not guarantee return on investment for residential and farm loads. Further, the Administrator's conclusion that COE is not a resource cost fails to recognize that the realities of utility financing.

The rates at which utilities are able to issue debt are directly related to their respective capital structures. The market would require a utility that is 100% debt financed to offer significantly higher rates of interest than a utility that is capitalized by both debt and equity. This is due to the leverage, that is, level of fixed interest payments and the perceived investor risk associated with the prospect that utility cash flows will be insufficient to cover the fixed debt interest payments.

BPA's practice of excluding the COE in IOUs' capital structure and using historically issued rates of interest for debt takes advantage of the IOUs' lower default risk, which was gained by issuing equity, while excluding the COE itself. Accordingly, BPA's current practice not only fails to recognize the realities of utility financing, but is internally inconsistent, to the detriment of IOUs.

The fourth underpinning of the Administrator's exclusion, that allowing cost of equity in ASC will shift excessive costs to BPA, is incorrect for the reasons stated above. A utility's equity costs are a resource cost within the meaning of § 5(c)(7)(c). It is not appropriate to manipulate the level of exchange benefits received by each IOU by artificially lowering the costs attributed the IOUs resources. To the extent that Congress intended to limit the amount of benefits afforded IOUs, it included a rate test in the Act. It is inappropriate for the Administrator to provide preferred customers further protections by controlling the outcome of the ASC determination by artificially lowering the costs of the IOU resources.

Should the Administrator include income and related taxes in IOUs' ASC when determining the exchange benefits owed to the utility under § 5(c) of the Act?

Yes. As with transmission costs and COE, the Administrator has authority to include income and related taxes in each IOU's ASC.[9] Whether he does so is a policy question, not a question of law.

Income taxes are a cost of doing business and includable in calculating utility rates and revenue requirements. Income is required by utilities in order to both cover expenses as well as provide dividends to shareholders. In establishing utility revenue requirements, income taxes are included. When a utility seeks to construct generation, the utility finances the construction of the plant using debt and equity. The return on equity, which

[8] Average System Cost Methodology ROD at 54.
[9] *See PacifiCorp v. FERC*, *supra*, 795 F.2d at 822.

includes dividends, is made available through the utility's net income-after taxes. Therefore income and revenue related taxes are an integral component of resource cost. It would frustrate the purpose of the Regional Power Act to exclude such a major resource cost component.

The issue of taxes included in rates being different than those actually paid has been a significant issue in Oregon. The 2005 Oregon Legislature passed SB 408, which requires rates charged to customers reflect only those taxes actually paid by a utility. BPA could adjust ASC to the extent state commissions adjust rates to reflect actual taxes paid. However, for administrative ease, BPA could consider not truing up ASC to account for the differences in taxes paid versus taxes included in rates. There are a host of accounting reasons why taxes paid might differ from taxes included in rates such as accelerated versus straight line depreciation.

The ASC should differ by state to take into account state specific tax differences. This avoids any perception that BPA is judging the reasonableness of any state specific tax rate.

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

No. Including the output Mid-Columbia hydro resources contracted to IOU's in the § 7(b)(2)(D) resource stack is inconsistent with the language of the Act.

The pertinent language of § 7(b)(2) is as follows,

> After July 1, 1985, the projected amounts to be charged for firm power for the combined general requirements of public body, cooperative and Federal agency customers * * * may not exceed in total, as determined by the Administrator, during any year after July 1, 1985, plus the ensuing four years, an amount equal to the power costs for general requirements of such customers, if the Administrator assumes that –
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> * * * * *
>
> (D) all resources that would have been required, during such five-year period, to meet the remaining general requirements of the public body, cooperative and Federal agency customers (other than requirements met by the available Federal base system resources determined under subsection (B) of this paragraph) were –
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> * * * * *
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> (ii) not committed to load pursuant to section 5(b).

As noted in BPA's request for feedback, investor-owned utilities are eligible § 5(b) customers. More specifically, § 5(b) concerns the load of investor-owned utilities as well as the load of public body and cooperative customers. Accordingly, to the extent § 7(b)(2) refers to resources "not committed to load pursuant to section 5(b)," it refers to resources committed to loads of investor-owned utilities as well as publicly-owned utilities. Because the output of the Mid-resources contracted for by the IOU's is committed to the utilities' firm load, these resources cannot be "Type 2" resources under the Act.

The 1984 Legal Interpretation of § 7(b)(2) does not reveal why BPA previously interpreted the § 7(b)(2)(D)(ii) reference to the load of § 5(b) customers as a reference to the load of its preference customers, as opposed to the load of *all* customers eligible for sales under § 5(b). However, given the express language of the Act, the Administrator's current interpretation is outside his authority. Meaning, the Administrator does not have discretion to ignore the plain language of the Act. Accordingly, Mid-C resources contracted to IOUs must be excluded from the 7(b)(2)(D) resource stack because these resources are committed to § 5(b) customers.

6. **Section 7(b)(2) specifies that the rate test should consider ". . . any year after July 1, 1985, plus the ensuing four years . . ." BPA has implemented this as applicable to the rate period plus the ensuing 4 years. An issue has been raised whether the rate test should be limited to the first year of the rate period plus the ensuing 4 years without respect to the length of the rate period.**

The Administrator's current methodology is inconsistent with language of the Act. The rate test in the Act expressly contemplates a comparison of rates over five-year periods. Specifically, § 7(b)(2) specifies that BPA will compare projected rates for "*any year*, [singular] plus the ensuing four years." Similarly, § 7(b)(2)(B) requires the Administer to assume for purposes of the rate test that "the public body and cooperative customers' general requirements had included "during *such five-year rate period*" certain direct service industrial loads. § 7(b)(2)(C) requires the Administrator to assume that the Administrator made no § 5(c) purchases or sales in "*during such five-year rate period*." Similarly, the assumption in § 7(b)(2)(D) is to apply to the "*five-year rate period*."

Notwithstanding the express language of the Act, BPA has interpreted the Act to allow a comparison of a multiple-year rate period, plus the ensuing four years. The express language of the Act, which calls for the Administrator to use a single year, plus the ensuing four years, does not allow the Administrator's current practice.

The difference between the express language of the Act and BPA's current methodology is easily seen in BPA's direct testimony in its 2007 rate case. Witnesses Keep, Doubleday, Brodie, and Mace discuss the (7)(b)(2) rate test, and describe the "test period for the 7(b)(2) rate test" as follows:

> In BPA's WP-07 Initial Proposal, BPA assumed a three-year rate period. The 7(b)(2) Implementation Methodology states that the test period will consist of the test year for the relevant rate case plus the ensuing four years. In developing the rates in BPA's initial proposal, BPA used all three years as the test period, i.e., a 36-month test period. Therefore, because the test period is three years, BPA used those three years (FY 2007-2009) plus the ensuing four years (FY 2010-2013) as the 7(b)(2) rate test period.[10]

[10] WP-07-E-BPA-27 at 4.

The flaw in this testimony is the BPA witnesses' assumption that the BPA test period that BPA chooses for the relevant rate proceeding dictates the length of the § 7(b)(2) rate test period. This is incorrect. The Act specifically refers to a single year, plus the ensuing four years. BPA cannot ignore the express language of the Act in order to match it [the Act] with current BPA practice.

Furthermore, while the Implementation Methodology does specify that the rate period for the 7(b)(2) test will "consist of the test year for the relevant rate case plus the ensuing four years," the Implementation Methodology assumes a single-year test year. This is clear in when reviewing the Methodology's entire directive regarding the § 7(b)(2) test period:

> The *five-year test period* will consist of the test year for the relevant rate case plus the ensuing four years.[11]

Accordingly, the conclusion that the § 7(b)(2) rate test period can consist of a period that exceeds five years is not supported by the Implementation Methodology.

8. Should the individual annual Program Case and 7(b)(2) Case rates be converted to constant dollars before averaging for comparison.

No. If BPA uses a nominal discount rate there is no need to express the terms in real dollars. The values would need to be discounted for inflation, to express them in real dollars, if the values are then present valued using a real present value rate. However, if a nominal discount rate is used to present value the dollars; that is a discount rate that consists of two components, the real discount rate and inflation, then the annual values do not need to be discounted by inflation. In other words, NDR = RDR + Inflation. So long as the same discount rate is being applied to the two streams of dollars, there is no difference between first applying the inflation factor (converting all information to real dollars) and then applying the real discount rate (RDR) and simply using the composite rate (i.e., the nominal discount rate) to discount the stream of dollars.

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

No. Resolution of this issue turns on the interpretation of "served" in §7(b)(2)(A). That section of the Act requires the Administrator to assume, for purposes of the § 7(b)(2) case, that the preference customers' general requirements had included the direct service

[11] Section 7(b)(2) Implementation Methodology at 5.

industrial loads that are "served by the Administrator" and located in or adjacent to the preferred customers' service territory. Accordingly, whether the Administrator's financial payments to the DSI customers in lieu of power should be "subtracted from the 7(b)(2) Case revenue requirement," depends on whether the payments fall within the definition of service.

Review of the Administrator's June 30, 2005 ROD for BPA's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 establishes that the DSIs receiving financial benefits in lieu of power deliveries are "served" by the Administrator. In Section VI of the ROD, the Administrator discusses how "to best structure the new contracts to deliver 560 aMW of service benefits to the aluminum smelter DSIs" and notes that the two primary elements "to be considered as part of this structure 'or delivery mechanism' are the rate schedule that will be employed, and whether the benefits will be delivered as: (1) physical power, or (2) the value of a physical contract monetized, based on its relative market value, and paid to the DSIs."[12]

In addition, the ROD contains other statements that reflect the Administrator determined in the ROD that he was serving the DSIs by providing the value of the physical contract monetized. For example, at page 22 of the ROD, the Administrator notes, "[a] number of parties supported BPA's straw proposal to deliver benefits through a financial mechanism that monetizes the value of a surplus below-market power sales agreement, up to a capped amount."

Because the Administrator treated the financial payments to DSI's as service for purposes of the 2005 ROD, the Administrator should treat as such for the § 7(b)(2) rate test.

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

The load should be treated as DSI load, or in the alternative, treated as new large single load and excluded from the publicly-owned utility's general requirements under §7(b)(4).

The Administrator discussed the three-party contract arrangement currently used by Clallum PUD and Port Townsend Paper in his 2005 Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011. The Administrator noted, with respect to the three-party contracts, that BPA would work with publicly-owned utilities "if they desire to play a role in service [to] the DSI located in their community, for the purpose of supporting their local economies." He noted that "among other things, BPA will work with the utilities to ensure that they bear minimal financial risk associated with the [three-party contract] transaction." The Administrator also rejected arguments that the structure of such a transaction would raise New Large Single Load issues. He noted that the

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[12] Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 ROD at 18.

fundamental distinction between the surplus sales proposed here, and a sale to the public utility to serve new industrial load on a requirements basis is that the sale could be made directly by BPA.[13]

Essentially, BPA has classified the load served by three-party contracts as DSI load for purposes of avoiding any limitations imposed by the New Large Single Load provisions of the Act. However, it does not treat this load as DSI load for purposes of the § 7(b)(2) test. This inconsistent treatment is inappropriate.

BPA should treat the load consistently for all purposes. Meaning, BPA should treat it as industrial customer load that it [BPA] serves for purposes of determining the rate to apply to the load and for purposes of applying the §7(b)(2) test. In the alternative, BPA should determine that the load is actually new load served by the publicly-owned utility, and exclude it from the publicly-owned utility's general requirements under §7(b)(4).

[13] BPA's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 at 23-24.