INFORMAL COMMENTS OF CONSUMER-OWNED UTILITIES IN RESPONSE TO THE AVERAGE SYSTEM COST METHODOLOGY WORKSHOP HELD JULY 31, 2026

Submitted: August 14, 2026

I. **Introduction and Background**.

The Consumer-Owned Utilities[1] ("COUs") appreciate the opportunity to submit these informal comments in response to the following select issues raised in the Average System Cost ("ASC") Methodology ("ASCM") workshop held by the Bonneville Power Administration ("BPA") on July 31, 2026 ("July 2026 ASCM Workshop"): (1) Return-on-Equity ("ROE"); (2) Account 925 1% Threshold; and (3) Market Price Forecast Options.

The region's investor-owned utilities ("IOUs") will have received approximately $4.066 billion in subsidies paid for by the COUs under the 2012 REP Settlement when it expires in 2028. As the primary funders of the Residential Exchange Program ("REP"), the COUs and the customers and communities they serve have a substantial financial stake in BPA's ASCM. Every dollar of additional REP benefit paid by BPA to the IOUs due to an improperly constructed ASCM imposes an incremental additional cost paid by COU customers. This push and pull of billions of dollars between the region's retail power consumers requires BPA to draw a line as to what costs can be included in an IOU's ASC for purposes of participating in the REP.[2] Not all IOU costs can or should be included in its ASC.[3] Otherwise, "utilities would have the ability to exchange almost any cost with BPA, with the illogical result that ASC would be the 'average' cost of operating the Utility, rather than the "average system cost of . . . **resources**"[4] permitted by Congress under the statute.[5]

Congress drew the initial lines in the Pacific Northwest Power Planning and Conservation Act ("Act" or "NWPA") as to what costs can and cannot be included in a REP participating utility's ASC by:

- Limiting the price of the power sold to BPA by an exchanging utility under the REP to "the average system cost of that utility's **resources**."[6]

- Narrowly defining "resource" to only include generating facilities and conservation measures.[7]

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[1] These comments are joined by the Western Public Agencies Group; Northwest Requirements Utilities; Public Power Council; PNGC Power; Benton PUD, Mason PUD #3, Seattle City Light; Snohomish PUD; and City of Tacoma, Department of Public Utilities, Light Division.
[2] 2008 ASCM ROD at 83.
[3] 1984 ASCM ROD at 58-60; 2008 ASCM ROD at 80, 83.
[4] *Id.* (emphasis added).
[5] NWPA § 5(c)(1).
[6] NWPA § 5(c)(1) (emphasis added).
[7] NWPA § 3(19).

- Excluding from the average system cost of resources sold by a participating utility to BPA under the REP the cost of:

    - Additional resources used to serve any new large single load of the utility;[8]

    - Additional resources used by the utility to meet load outside the region;[9] and

    - Any generating facility that is terminated prior to initial commercial operation.[10]

- Reserving in BPA the authority to exclude other costs from ASC, in addition to those expressly excluded by the Act under § 5(c)(7).[11]

As stated in our prior comments, the 2026 ASCM presents BPA with the opportunity to correct the deficiencies of the 2008 ASCM by more closely adhering to the plain language of the Act. This specifically includes § 5(c)(1) and § 5(c)(7), as informed by the Act's legislative history. BPA must ensure that the 2026 ASCM includes only the costs of a participating utility's "resources" and excludes all resource costs that are required to be excluded by the Act. BPA must exclude from the ASC such other costs (and otherwise designs the 2026 ASCM) as necessary to ensure that BPA does not become the "deep pocket" to which the IOUs shift excessive or improper resource costs.[12] Further, the methodology should also "give participating utilities an incentive to minimize their costs."[13]

In consideration of the above ASCM related obligations, the remainder of these informal comments focus on the substantive issues identified above from the July 2026 ASCM Workshop.

II. <u>**Informal Comments on Select Issues from the July 2026 ASCM Workshop**</u>.

A. **Return-on-Equity**.

<u>*Summary of Issue*</u>

The Draft 2026 ASCM would permit the inclusion of ROE, and would use the most recently approved Regulatory Body Rate Order to determine the ROE to be included.

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[8] NWPA § 5(c)(7)(A).
[9] NWPA § 5(c)(7)(B).
[10] NWPA § 5(c)(7)(C).
[11] *Pacificorp v. F.E.R.C.*, 795 F.2d 816, 822 (9th Cir. 1986) (holding that BPA has the discretion to exclude costs from ASC in addition to those expressly excluded under § 5(c)(7) of the Act).
[12] 1984 Average System Cost Methodology Record of Decision at 9, 54 (June 1984) ("1984 ASCM ROD"); 2008 Average System Cost Methodology Record of Decision at 4 (June 2008) ("2008 ASCM ROD").
[13] 1984 ASCM ROD at 9.

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BPA is weighing whether and to what extent it should include an ROE, or profit adder, to the IOU's eligible resource costs. The COUs are requesting a return to the weighted average cost of long-term debt as under the 1984 ASCM. Accordingly, BPA staff is considering and seeking feedback as to whether BPA should use the ROE in the exchanging utility's FERC-approved transmission rates to remove the transmission-associated ROE from the state commission-approved ROE.

COU Position

The ROE in the ASC should be based on each IOU's weighted average cost of long-term debt, and should not be based on a utility's most recent Regulatory Body-approved return. As an initial matter, we remind BPA that the REP is not a *retail rate* subsidy. Its sole purpose is to give the residential and small farm customers of IOUs the cost benefits of federal generating resources by allowing IOUs to exchange resource costs. Thus, there are components that may be properly included in the IOUs' retail rates but that must be excluded from ASC. The amount of ROE in excess of an IOU's weighted average cost of long-term debt is one such retail rate component.

This is neatly demonstrated by BPA's proposal to adjust the retail ROEs approved by the state commissions to remove the transmission-associated ROE. As explained above and in the COU comments submitted April 2, 2026, the price of the power sold to BPA by an exchanging utility under the REP is limited to "the average system cost of that utility's **resources.**"[14] "Resource" under the Act is narrowly limited to only include generating facilities and conservation measures.[15] Because transmission facilities are not generating facilities or conservation measures, transmission related costs cannot be included in an exchanging utility's ASC for purposes of the REP. This includes transmission-associated return on equity. If adopted, BPA's proposal would address a latent legal defect in the Draft 2026 ASCM.

State commission and FERC precedent provide further support for BPA's proposal by recognizing that different utility functions can have different risk and capital characteristics. That precedent reflects a broader regulatory principle that the return required to attract capital can vary with the particular risks and investment characteristics of the utility function being financed. State commissions also use hypothetical capital structures and may authorize different ROEs for the same multistate utility in different jurisdictions, further demonstrating that regulatory return assumptions can be tailored to the circumstances of the business being regulated rather than treated as fixed attributes of the utility as a whole. For example, state commissions have expressly differentiated equity risk among distribution-only, fully integrated, and generation-only utility operations, while FERC has recognized distinct transmission investment characteristics through transmission-specific ROE incentives.

The COUs also continue to broadly disagree with the inclusion of any ROE amount in ASC above an exchanging utility's weighted average cost of long-term debt. As discussed in our April 2, 2026 comments, exposure to extraordinary liability risks, including wildfire-related and extreme

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[14] NWPA § 5(c)(1) (emphasis added).
[15] NWPA § 3(19).

weather-related costs, has become an increasingly important factor in the financial risk profile of western utilities, and these risks are reflected in the ROE approved in state regulatory proceedings. If such costs are also incorporated directly into ASC calculations, e.g., through BPA's treatment of Account 925 of costs, then the COUs paying the cost of the REP would effectively bear both the risk premium embedded in authorized ROE and the realized costs associated with the risk. To prevent this double recovery, BPA should reduce or eliminate the ROE included in ASC in the ASCM.

In addition, as the entity administering the REP, BPA has a duty to be appropriately skeptical of the ROE determinations of the IOU's retail rate regulators rather than accept such decisions *carte blanche*. State regulators serve a narrower constituency than BPA and are motivated to find ways to ease the financial burden of IOU ratepayers by maximizing REP benefits without regard either to the corresponding costs to COU consumers or adherence to the NWPA.

Towards such ends, ROE presents utility commissions with a "backdoor" to indirectly include in a regulated utility's ASC expenses that would otherwise be prohibited under the ASCM or BPA's statutes so that such prohibited costs would be offset, even in part, by an increase in the REP rate subsidy paid for by BPA's COU customers. During the 1980s, a utility commission granted a regulated utility an exceptionally high ROE to provide it with a return on a terminated nuclear plant, an outcome expressly prohibited by the Act.[16] Today, the appeal might be to permit a higher ROE so that the regulated utility can effectively exchange wildfire liability costs arising from the imprudent, unreasonable, or negligent operation of the utility's transmission or distribution functions. In the future, there may be other issues that entice a utility commission to permit a higher ROE so that a regulated utility can exchange costs prohibited under the ASCM or the Act.

The obscure processes used by the various state commissions for determining the ROEs of the utilities they regulate will make it extraordinarily difficult for BPA to identify any inappropriately applied costs with certainty. This is particularly true where, as the IOUs themselves have acknowledged, the rates of a regulated utility are frequently settled without a clear determination of individual issues/costs in light of the benefits of the settlement as a whole.[17]

Given the opaqueness of the underlying basis for ROE determinations, and the extraordinary non-resource cost pressures that the region's utilities are facing (e.g., wildfire liability and extreme weather-related costs), the possibility that a state commission could approve an increase to a regulated utility's ROE to facilitate the utility's indirect exchange of prohibited costs is not *de minimis*. To reduce the impacts of rate increases on the residential customers of the region's IOUs, state commissions may have an incentive to shift the recovery of otherwise prohibited costs to a higher ROE to produce a higher offsetting REP subsidy that reduces the overall net rate impact. Due to the circumstances discussed above, it would be extremely difficult for BPA to parse through the ROEs of the IOUs to ensure that such cost misdirection does not

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[16] 2008 ASCM ROD at 103 (recounting that a utility "attempted to unlawfully include terminated plant costs in its retail rates and its ASC"); 1984 ASCM ROD at 15, 53.

[17] *See* IOU Informal Comments in Response to BPA Preliminary Draft Average System Cost Methodology at 4 (January 21, 2026); *see, also*, Comments of the State of Washington Utility and Transportation Commission at 2 (January 21, 2026).

happen. However, that is precisely what BPA will need to do if it does not adopt the COU proposal to limit an exchanging utility's ROE to its weighted average cost of long-term debt.

There is no question that BPA has the authority to decide this question; indeed, it has done so before. The 1984 ASCM ROD concluded that ASC "should include neither equity nor coverage requirements because these are costs related to default risk," reasoning that "BPA effectively eliminates default risk by guaranteeing the return on investment for residential and small farm loads."[18] BPA further explained that "the residential exchange program is not governed by ratemaking principles," and that in developing an ASC methodology the Administrator "has considerable discretion in deciding whether to permit inclusion of an equity return allowance and, if so, how that component is to be determined."[19] In approving the 1984 methodology, FERC confirmed that discretion, holding that "Congress chose the Administrator to determine cost of Utility resources," and that had Congress intended the Administrator to follow state commission determinations of a utility's resource costs, "it could have easily included this requirement in the statute."[20] This language should effectively foreclose any suggestion that BPA must accept a state commission-approved ROE simply because § 5(c)(7) does not name it as an excluded cost.

As set forth in our April 2, 2026 comments, BPA can implement the COU proposal directly by removing § 301.4(o)(1)–(3) from the Draft 2026 ASCM and incorporating language similar to footnote d/ of the 1984 ASCM, which limited the overall rate of return applied to a utility's rate base to that utility's *weighted average cost of long-term debt*. The Draft 2026 ASCM already applies a debt-based return in § 301.4(o)(4) to utilities that do not use depreciation for jurisdictional rate setting, so the mechanism is present in the methodology; the question before BPA is the scope of its application.

For the reasons discussed above and in the COU comments submitted April 2, 2026, BPA should adopt the COU proposal on ROE.

B. **Account 925 1% Threshold**.

<u>*Summary of Issue*</u>

The Draft 2026 ASCM would permit the inclusion of Account 925 (injuries and damages) costs. The functionalization to production of an exchanging utility's Account 925 costs in an amount that is less than 1% of the utility's total system cost would be automatically included in the utility's ASC. Account 925 amounts functionalized to production in excess of 1% must be approved for retail rate recovery by the state commission before being included in ASC.

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[18] 1984 ASCM ROD at 54. The decision adopted the embedded cost of long-term debt as "the appropriate measure of the overall rate of return for calculation of ASC." *Id*. at 55.

[19] 1984 ASCM ROD at 54; 49 Fed. Reg. 4230, 4235 (Feb. 3, 1984), quoted in 2008 ASCM ROD at 103.

[20] 49 Fed. Reg. 39,293, 39,296 (Oct. 5, 1984), quoted in 2008 ASCM ROD at 103. This is consistent with *Pacificorp v. F.E.R.C.*, 795 F.2d 816, 823 (9th Cir. 1986), supra.

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All stakeholders who submitted comments objected to BPA's proposed 1% of total system cost threshold. BPA is seeking input on whether there are standard materiality thresholds in use at the state commission level, and how similar percentage-based thresholds could apply to the inclusion of Account 925 costs in the ASCM.

COU Position

The COUs renew our request for BPA to return to the language from the preliminary ASCM to address concerns about the automatic inclusion of any level of Account 925 costs, as well as our request that all Account 925 wildfire related costs be categorically excluded from ASC. BPA's desire to benchmark standard percentage-based thresholds used by the state commissions to determine materiality is understandable. But it misses the underlying point of our objection to BPA's proposal. In BP-26, 1% of the collective contract system costs of the IOUs was approximately *$80 million.* As the total system costs of the IOUs continue to grow, this could increase to potentially hundreds of millions of dollars per year. BPA's workshop materials illustrated the fact that PacifiCorp's Account 925 costs rose from less than $12 million for base year 2021 to over $725 million for base year 2023, driven in large part by wildfire liability.[21] A single utility's Account 925 balance in one base year exceeded, by a wide margin, the one percent figure BPA proposes to admit automatically.

Even in today's world, 1% of Account 925 is material to BPA and to the retail ratepayers of the COUs. Such material costs should not be *automatically* added to a utility's ASC without an affirmative demonstration by the utility that they are eligible resource costs. Using a different state commission approved materiality threshold or methodology would not assuage our concerns if it would likewise automatically approve materially high 925 Account costs. No percentage threshold, at any level, is a substitute for the affirmative demonstration the Act requires.

What is more, the various thresholds identified by BPA at the July 2026 ASCM Workshop are a bad proxy for determining materiality under the ASC because they are intended to be used for entirely different purposes.Utility rates are set prospectively by state utility commissions and are based on a determination of the revenue that IOUs need to collect from their customers to continue providing service during the rate period and recover their reasonable and prudent costs of service and have an opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks. That estimate already reflects normal operating risks and may include irregular costs through forecasts, normalization, or averaging, and other variable costs may be recovered through automatic adjustment mechanisms such as power-cost adjustment mechanisms. A cost therefore does not need deferred-accounting treatment merely because it is unusual or varies from year to year.

Deferred accounting is a special state proceeding that preserves a discrete cost or revenue for possible treatment in future rates outside of a rate case, without deciding whether it will ultimately be recovered or refunded. It can operate as an exception to the rule against retroactive

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[21] Post-2028 Residential Exchange Program ASCM Incremental Draft Workshop Presentation at 13 (Feb. 13, 2026); *see* COU Comments at 11 & n.40 (April 2, 2026).

ratemaking, which generally prevents a commission from changing current or future rates to recover costs or refund revenues attributable to a past period. Because deferral operates outside ordinary prospective ratemaking, commissions often hold deferral decisions to a high bar and review deferral requests on a case-by-case basis by considering whether the event was foreseeable or already reflected in rates, the magnitude of its financial effect, and whether a later recovery or refund would be appropriate.

The percentages associated with deferred accounting reflect that exceptional situation and should not determine how costs within Account 925 are treated in the ASC methodology. A 5%-of-net-income test has been used to screen whether a cost is sufficiently extraordinary to qualify for deferred accounting treatment, while Oregon's 3%-of-gross-revenues provision generally limits the annual rate effect of amortizing deferred balances. These are intentionally high safeguards at different stages of deferred accounting of costs handled outside ordinary ratemaking; they do not show that costs below or up to those levels should automatically be included in ASC, particularly when base rates and adjustment mechanisms can already account for material and irregular costs.

Audit-materiality percentages are also a poor fit. Auditors use them to plan their work and identify potential financial-statement errors that warrant closer review; they are not designed to determine whether an actual cost is reasonable, prudent, or eligible for cost recovery and inclusion in rates paid by customers. The SEC likewise explains that a percentage is only the starting point of a materiality analysis and cannot replace consideration of the nature and circumstances of the item. Accordingly, audit-materiality percentages should not be used as fixed thresholds for including costs in the ASC calculation.

C. **Market Price Forecast Options**.

Summary of Issue

The Draft 2026 ASCM proposes to alter how sales for resale and power purchases are to be calculated, including specifically what market price methodology would be used and how. The ultimate result of this methodology determines a utility's 'net purchase and sale' value which is additive to a utility's ASC. As the 'net purchase and sale' value increases, it is added to a utility's Contract System Costs and increases the ASC proportionally. BPA's draft proposal has thus proposed a base-year estimated purchase and sale price that is then adjusted forward for the exchange period. In this proposal, utility-specific actuals in the base period would be scaled up and down annually by BPA's market price forecast. BPA initially proposed a 5-year basis of actuals for the 'Base Year' and has subsequently shifted to a 3-year basis. As the COUs noted in April, the prior draft applied a 5-year basis to the average short-term purchase and sale prices and retained a 5-year basis for the spread calculation; BPA has since resolved that inconsistency by conforming both to 3 years.[22] The COUs appreciate the correction of an internal inconsistency and request that BPA resolve it in the other direction, by applying a 5-year basis throughout.

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[22] *See* COU Comments at 15-16 (April 2, 2026); Post-2028 REP ASCM Workshop Presentation at 17 (July 31, 2026) (describing the correction to § 301.5(b)(2)(ii)(D)).

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BPA is now considering an alternative market pricing methodology (Option 2) used to extrapolate the base-year purchase and sale estimates into the exchange period.

Option 1 uses market price Escalation Factors to adjust all purchase and sales values from the Base-year forward into the exchange period. These 'Escalation Factors' are dynamic, and produce non-linear extrapolations of the net purchase and sale values based in part on BPA's methodology and in part on BPA's market price forecast.

Option 2 replaces the 'Escalation Factors' with a more direct application of BPA's rate-case market price forecast to marginal load growth above the base year to arrive at purchase and sale values. Incremental load growth is met with purchases and sales, which are additive to the Base-Year to arrive at Exchange-Period estimates.

Both methods rely on a 3-year weighted average of actual purchase and sale values in the Base Period.

COU Position

We are still analyzing possible implications of this proposed Option 2, but maintain that a 5-year basis for the Base-Period is a more stable, and appropriate basis for this critical component of the ASCM (as discussed in the COU comments submitted April 2, 2026). To summarize, a three-year basis is reactive to short-term fluctuations in supply, demand, and other market fundamentals. Weather-driven events alone, such as an unusually warm, cold, or dry year, can swing the Sales for Resale account, and with it a utility's ASC and the downstream REP benefits and rates. A 5-year basis dampens those fluctuations and produces price signals better attuned to long-run incremental costs, consistent with the stability and predictability criteria that have long guided utility rate design.[23] Model sensitivity reinforces the point: REP outputs are notoriously sensitive to small changes in inputs, and introducing stability on the input side is prudent wherever it is practical.[24]

BPA's own record supports a longer averaging period. In the 2008 ASCM proceeding BPA proposed a rolling 5-year average precisely because it "recognize[d] that a single-year's FERC Form 1 short-term purchased power and sales for resale revenues might not accurately represent future short-term purchased power and sales for resale revenues under normal operating conditions."[25] BPA moved away from that proposal for reasons of administrative practicality tied to the difficulty of normalizing each utility's generation operations, and it relied on the redetermination of ASCs every two years to let year-to-year variation "even out over time."[26]

[23] COU Comments at 15-16 (April 2, 2026) (citing James C. Bonbright, Principles of Public Utility Rates at 290-91 (1961)).
[24] COU Comments at 16 (April 2, 2026).
[25] 2008 ASCM ROD at 57. The Washington Utilities and Transportation Commission likewise argued that "five-year rolling averages would be more representative of expected actual figures than data from a single FERC Form 1 or any other single, historical year's data." *Id.*
[26] 2008 ASCM ROD at 58.

Neither rationale addresses the COU concern. A longer averaging window requires no normalization of generation operations, and the volatility now at issue arises from market prices during a period of significant regional load growth and resource development.

Option 1 applies market-price based Escalation Factors to the base period and to all MWh's of purchases and sales. This option appears to create more possible divergence from the Base-year purchase and sale value than does than Option 2. While still under consideration, the Base-Year estimate in Option 2 more closely relies on historical actuals with only load growth dependent on BPA's market forecasts. This approach, grounded and weighted more prominently in historic actuals, and reflects actual costs incurred upon which to build exchange values.

Before parties are asked to choose between the options, the COUs request that BPA publish comparative modeling of Option 1, Option 2 on a three-year basis, and Option 2 on a 5-year basis, computed against actual BP-26 filings.

Thank you for the opportunity to comment.