MEMORANDUM

To: John Hairston, BPA Administrator

From: PNGC Power

August 10, 2022

COMMENTS ON BPA POST-2028 CONTRACT CONCEPT PAPER

PNGC is a wholesale G&T that serves 16 retail electric cooperatives entitled to preference power from BPA. PNGC is a statutorily organized Joint Operating Entity and as such is the second largest power customer of BPA.

While there are several items noted in BPA's July 2022 "Provider of Choice" Concept Paper (Concept Paper) which we think are headed in the right direction, PNGC has serious concerns and reservations about key aspects of the Concept Paper. We do not see several of the elements as being consistent with either statute or the reality of the future we all face together. We understand that BPA has been clear this is just a starting place for the discussion. Accordingly, we are providing our primary observations at this point in the process, listed below.

Meeting Net Requirements at Cost – When requested, BPA is obligated per statute (Power Act: 839e. Rates (USC numbered) (nwcouncil.org)) to meet preference customers' net requirements (capacity and energy) at cost-based rates and we do not see that BPA is committing to that in its Concept Paper. Under the current Tiered Rate Methodology (TRM) used in the Regional Dialogue Contract (RDC), opportunity cost-based pricing for Tier 2 has been used to set prices, even when BPA serves Tier 2 loads with surplus federal power. We think this is a mistake and must be corrected in the next contract. Tier 2 should be priced at actual cost for both capacity and energy. When there is output from the federal system beyond what is defined as critical firm, it should be used to provide power to serve regional Tier 2 preference obligations before selling it off to the highest bidder, either in the wholesale market or through bilateral contracts. It is not consistent with the statute that some preference customers are able to sell off excess BPA power at a profit while at the same time, other preference customers are not allowed access to cost-based BPA power supply, when it is available, to meet their full net requirements. The statute is clear that cost-based rates apply to net requirements, and this extends to AHWM needs.

Importantly, PNGC can support the TRM and asserts that the sanctity of Tier 1 pricing, coveted by so many, can still be preserved while not leaving Tier 2 customers subject to the volatility of short-term wholesale market prices. The proportion of federal power used to supply Tier 2 net requirements should be priced at the same rate as Tier 1 power. To the extent additional purchases are required to augment the federal system, these costs should be blended into the overall Tier 2 rates to reflect the actual cost of power. This is the essence of cost-based pricing. While we can support using the actual marginal cost of power as the basis for Tier 2 prices, we do not see "opportunity-cost based pricing" as being consistent with the statute or long-held regulatory definitions of cost-based rates. Tier 2 is still net requirements and preference power is entitled to "firm" service to meet these load requirements at cost-based rates. It is not reasonable nor prudent for this fundamental divide between Tier 1 and Tier 2 to continue as it has existed under the current contract.

System Size, Augmentation and Allocation - A lot of concern has been expressed by BPA about augmentation and the cost risk of growing the size of the Tier 1 system. This position was further underscored by the recommendation of a fixed system size at 7,000aMW. We have several points to offer on system size. The first is that the system needs to be sized to meet all net requirements, defined as both capacity and energy, at the onset of the next contract. We see ample evidence that energy-only resources can cost-effectively be integrated by leveraging existing federal system capacity rather than selling it off to non-preference (and often out of region) off-takers. There is also potential with the Columbia Generating Station uprate to add significant base load resource in addition to that amount. These should be the minimum considerations for the potential Tier 1 system size. We would also suggest looking at the potential cost impacts of adding other baseload resources or capacity resources if the sum of these two paths does not meet net requirements for all preference customers at the start of the contract. The region as a whole is facing the need for new renewable resources and the resources needed to serve public power can be more cost-effective if we leverage the buying power of the group, rather than leaving each utility to fend for themselves in the resource development space. For the smallest utilities in public power, this is simply an unrealistic burden to place on them. For most others facing load growth, the economics and reliability considerations favor a pooled approach to resource acquisition.

We think BPA should commit to expand/augment the federal system to meet net requirements at cost-based rates or at a minimum adopt policies and rate structures that better enable customers to do so on their own. As a related matter, we reject the idea that some customers should begin the next contract with full net requirements met (plus headroom potentially) while the net requirements of other utilities with equal statutory rights are not met by the critical firm federal system ("firm" power). One set of customers' needs do not outweigh another, and all BPA customers should be on equal footing at the start of the next contract. There is no statutory or contractual argument that would support any initial starting point where some customers have surplus BPA power (aka "headroom") at the same time others have a deficit (or AHWM load). There should be no "carry over" from one contract to the next of any terms that aren't statutorily granted.

Another benefit of augmenting the federal system to meet all net requirements and selling Tier 1 and Tier 2 power at cost-based rates is that it will help stabilize BPA's sales volume and revenue by making secondary revenues less volatile. If the Tier 1 system is not augmented to ensure net requirements are met by actual generating resources, arriving at any consensus regarding how to allocate the scarcity implied in a "short" Tier 1 portfolio will be virtually impossible. Since the Tier 1 obligation is going to be a take-or-pay contract, the risk is all on the customers, so why not expand the system to meet all customers' needs? If that proves unworkable, BPA can at least serve Tier 2 load at a blended, cost-based rate.

We further point out that billing credits are a statutory[1] approach that can ease some of the burden on BPA for resource additions and, as such, ought to be factored into the augmentation strategy. While historically augmentation was an expensive undertaking, typically priced above the Tier 1 rate, costs for energy-only resources have become very competitive. Located advantageously, augmentation might be equal to, or possibly cheaper than, BPA's current Tier 1 rate by leveraging (and even extending) the available capacity in the federal hydro system. Lastly, we lean toward a fixed system size, if adequate to meet all net requirements, and think that any augmentation amount should also be considered as a fixed-size, incremental addition. It is clear that making the system too small is already leading to an unnecessary and unwise rift across public power caused by the attempted allocation of scarcity. We ought to be working together to consider the long-term needs of the region as a whole and ensuring we are adding resources for the future.

- **Tier 2 Power** - In the Concept Paper, it appears that BPA is proposing to offer "real" full requirements service only if you pick Load Following service with AHWM loads served by BPA-acquired Tier 2 resources. The proposal also suggests that BPA has a preference for allowing for just a one-time choice for the entire contract term on whether to procure Tier 2 net requirements from BPA or to self-supply. Since there is no cost certainty at all being proposed for the BPA-supplied Tier 2 option, this is simply unworkable. We acutely understand the implications of needing lead-time to plan to meet Tier 2 obligations with anything other than short-term market purchases. Customers with AHWM have been facing this issue for some time now. We are certain reasonable terms can be established that meet both BPA's and its customers' needs.

  We need to find a solution that is more reasonable than either a 20-year commitment to a completely unknown cost trajectory (BPA Tier 2 pricing) or a "you are on your own" designation that also leaves an open-ended level of uncertainty, since BPA can unilaterally change the terms of delivery and integration costs for self-supplied assets at any point over the 20-year contract. While BPA needs a level of certainty on their power portfolio obligations, its customers also need some certainty on the cost and availability of transmission and resource integration terms to make self-supply a viable alternative.

  BPA has stated several times that seeing new renewable resources added to the region is a policy objective. We also see this as a statutory requirement. PNGC and several others in public power are up for the task of adding renewable resources to meet future load growth but we need reasonable and stable terms and products from BPA to make that happen. Effectively, BPA has proposed unworkable business terms in its Concept Paper. First, BPA seems unwilling or at least reluctant to meet all preference customers' net requirements at cost-based rates. BPA's Tier 2 option (for BPA-supplied power) is being proposed as a one-time choice to accept an unknown and uncertain short-term market price alternative. Although BPA does not say that customers cannot pursue their own AHWM self-supply options by adding non-federal resources to their portfolio, the current RDC already make this very difficult and BPA's Concept Paper proposal, if implemented, would make this option practically impossible.

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[1] NW Power Act 1980 Rates section
[Power Act: 839e. Rates (USC numbered) (nwcouncil.org)]

- **Consideration of Non-federal Resources and Transfer Service** - Of particular concern in the initial BPA Concept Paper is the proposal that the cost of securing transmission for non-federal resources delivered with transfer service would be direct assigned to off-takers while all BPA-supplied transfer service costs would continue to be rolled into Power rates, as they are today. While we appreciate the assertion that transfer service should continue to be rolled into power rates (as it is and will remain a statutory obligation on the Power side of BPA to provide delivery for preference power), this is a very strong disincentive for transfer customers to invest in non-federal resources and frankly amounts to discriminatory pricing. An additional factor is that transfer customers are often located exactly in the places where resource development would benefit BPA and its customers the most. We are further concerned by the statements asserting that BPA will no longer seek to meet the comparability principle of service levels for transfer customers as part of the Provider of Choice contracts, a point that defies over 35 years of FERC precedent regarding open access to transmission resources.

  We appreciate that it can be more administratively burdensome for BPA to administer transfer contracts for non-federal resources, but in the overall picture, not having to build new transmission to these utilities who are entitled to delivered preference power and are outside the BPA BA, still saves BPA and its customers much more money than the added administration costs.

  We are encouraged to see the statement that integration costs for non-federal resources applied to Load Following service will be revisited and look forward to seeing more specifics on the BPA proposal. However, BPA would be counteracting potential resource integration reform objectives if you handicap transmission access (comparable transfer service) for non-federal resources. Pancaked transmission rates would continue to make non-federal resource development cost-prohibitive for transfer customers – a significant impact to more than half of BPA's customers. BPA has said that there is little non-federal transfer currently in place, so it can't be a cost driver that is making the "PF rate non-competitive" (BPA's stated concern). If development of non-federal resources is a policy directive of BPA, then don't harm it through cutting off customers from reasonable access to transmission - especially those that have sacrificed transmission security over time (transfer customers) to save BPA, and its customers, the significant costs of transmission development to serve these loads directly. If BPA isn't going to provide comparable access to transmission for non-federal resources, then it really needs to grow the federal system to meet all current and future preference customers net requirements or make plans to expand the federal transmission system.

  Of particular note, we would like to also address the 5 MW self-generation cap proposed in the Concept Paper. We see this as being in direct conflict with what the region is trying to accomplish and what CETA is mandating WA utilities to do. We do not fully understand the purpose of the 5 MW cap. The Concept Paper suggests anything over that amount would be an offset to Tier 1 allocation. However, in the workshop BPA staff repeatedly stated that it would not. If not, what is the point of the cap? If BPA does not augment the system to meet future load growth that qualifies as net requirements under the statute, then any utility wanting price stability will need to do so and many will need more than 5 MW over the course of the next contract period. We suggest removing the cap on the addition of consumer-owned generation. The more generation that is produced locally, the further the federal hydro resources can be stretched to meet contractual needs for preference customers and enhance the reliability of the region as a whole.

To close this section, we offer that there are five primary ways BPA can facilitate non-federal resource development by its customers, through: (1) resource integration reforms (RSS priced at actual cost for Load Following customers), (2) developing and offering a capacity product to customers, (3) not applying a cap to the amount of generation a preference customer can add to meet their Tier 2 obligation, (4) the use of billing credits for customer resource development for augmentation, and (5) keeping non-federal transfer service rolled into power rates, similar to how BPA proposes to treat BPA-provided Tier 2 power. Together we can solve the need to add new resources to meet the inevitability of a growing net requirement obligation.

- **Defining Peak Net Requirements** - We are encouraged to see that BPA is proposing to define peak net capacity for products in the next contract. We think it is necessary for BPA to clarify its capacity obligations to all preference customers in this contract. Capacity will be one of the region's biggest challenges going forward and we need to know now how it will be apportioned to preference customers. We have been, and continue to be, advocates of making any excess capacity in the federal system available to preference customers to meet net requirements obligations at cost. We think all product lines should have some form of access to this capacity at cost-based rates, subject to the constraints defined by net requirements.

- **Treatment of Secondary Revenue** - We are interested in the idea proposed for crediting secondary revenue outside of a Tier 1 rate offset. This would provide a much more transparent and stable price signal for the cost of Tier 1 power. BPA mentioned it also reduces its own revenue risk. Several preference customers inquired in the BPA Concept Paper workshop as to how this would translate to reduced reserve thresholds for BPA commensurate with the risk reduction. We look forward to additional conversation along these lines.

- **Capacity Pricing Reform** - We are encouraged to see the discussion of capacity pricing reform and the potential elimination of the CDQ. As with energy, our request is that any "Tier 2" capacity pricing be set based on actual incurred marginal costs rather than opportunity cost. If it comes to pass that CDQ or a similar construct continues in the next contract, we ask for equitable pricing for similar load factors across customers, rather than setting all costs relative to load shapes at a specific point in time.

- **Contract Term** - We are concerned about BPA's unwillingness to entertain a shorter contract. A 19- or 20-year contract in these times of increasing uncertainty, particularly when there are no cost controls or off-ramps in place, is a significant ask. We understand that BPA wants to minimize its risk, but simply transferring all that risk to customers doesn't set the table for a healthy partnership between BPA and its preference customers. At a minimum, we think BPA should consider a contract period that expires prior to the potential CGS license expiration date (12/20/2043). It doesn't make sense to leave open the potential for massive augmentation in the final year of the contract. It would be much simpler to set new contract terms that can accommodate quantity and price changes resulting from the outcome of the CGS decisions regarding relicensing.

- **CHWM Headroom Granted for Conservation** - We are aware of the considerable debate that has transpired regarding how to acknowledge conservation in the next contract. We think that BPA's proposal to focus on current and future activity rather than past activity, as well as the focus on self-funded conservation are the appropriate and equitable approaches to acknowledging conservation efforts through the granting of Tier 1 “headroom” at the outset of the next contract. This forward-looking approach creates a clear incentive to continue conservation through the remainder of this contract and helps offset potential augmentation needs that could be placed on BPA.

Conservation has created considerable value to many customers over the course of the RDC by creating CHWM headroom that insulates them from Tier 2 price volatility. Some communities have made their own policy decisions to do more conservation than BPA has deemed as both needed and cost-effective based on their own governing body recommendations, state mandates, or because it is consistent with their community’s values. In general, we believe the costs associated with those decisions should remain in the communities that have made these decisions. However, we also understand that this is an important issue for some BPA preference customers stakeholders.

Focusing on just the self-funded aspect of conservation, should it be ultimately used as a vehicle to grant CHWM headroom to customers in the next contract, acknowledges the value this activity brings to the region and yet doesn’t reflect the “double-counting” of conservation efforts were it to be based on conservation achievements already reimbursed by BPA. Further, the forward-looking aspect lays out a clear opportunity that all preference customers can act upon, while still providing advantage to utilities that already have robust EE programs in place (as it takes time to get them up and running) and that seems fair. It is further important to note that not all rural utilities have the same opportunities as urban utilities to have a “robust EE program” since residential-dominated utilities have far fewer EE opportunities in general, a point that inherently disadvantages rural utilities if 20 years of headroom were to be awarded based on conservation achieved.

A final point regarding conservation is that Energy Efficiency is treated as the first resource BPA can acquire to meet preference load. In that context, it should be treated similarly to public power investments in other resources that also reduce the need for BPA to augment the federal system in the future. Changing the rules retroactively, by granting new value in the form of headroom for actions taken in the past, is not fair to the utilities that chose to invest in local renewables resources rather than conservation resources to offset future net requirements.

Carbon-Free Portfolio and Renewable Energy Development in the Region – In the BPA Concept Paper, there is an exploration of various ways BPA can enhance the carbon-free nature of its Tier 1 portfolio, including a reinterpretation of its single source requirement under the Northwest Power Act. However, the paper also indicates that BPA may not be able to achieve 100% carbon-free power as Washington state’s CETA regulation will require in the future. While it is encouraging to see BPA consider options to help its Washington customers meet their regulatory obligations, we think there should be a stronger commitment to finding solutions. BPA, in coordination with its preference customers, WA state regulators, and other stakeholders, can surely find a path forward that will help its customers meet the 100% carbon-free requirement laid out in CETA by 2045. Even if the date lies outside the next BPA contract, we will still need to find solutions during the contract period.

BPA needs to provide reporting for all generation sources acquired (including Tier 2) to meet CETA reporting requirements. Otherwise, utilities will be penalized under CETA for "unspecified" resources. For fairness, we also think that it will be important (absent similar regulation emerging in other states in the region) that BPA find a way to direct the marginal costs of a 100% carbon-free portfolio to the customers that either need or elect a 100% carbon-free portfolio. Lastly, we would like to point out that the policies BPA enacts to discourage the self-development of renewable energy over the next contract, such as: 1) opportunity cost pricing for resource integration, 2) forced designation to load of new resources added (or a cap to what a customer can develop, as indicated in the 5 MW limit proposed), and 3) direct assigning the full cost of transfer service to customers with non-federal resources, will serve as disincentives for the region to meet these carbon goals.

Significant challenges to meeting the region's growing demand for power have been identified by key studies (see footnote)[2] and concerns about resource adequacy are exacerbated by the forecast for electric load to double by 2050 - on the same timeframe that CETA mandates for decarbonization mature. PNGC supports the recent E3 study, which shows that new generation is needed to augment current generation if our region is to avoid future power outages.

Because of these real and documented challenges for resource adequacy in the region, the lack of commitment in BPA's Concept Paper to finding solutions are serious concerns. We do not think BPA wants to be seen as creating roadblocks or forcing its preference customers to leave BPA due to conflicting regulatory directives. It is far too early to state that something cannot be done in this space.

In summary, while there are a few aspects of the proposal, such as defining peak net requirements, that do endeavor to address emergent and pressing issues in the region, in many instances BPA is taking something (the regional dialogue contracts and tiered rate methodology) that is out-of-date and does not meet our future needs, and again proposes to transfers all the risks to customers in the form of another “blank check” while still proposing another 20-year contract term despite the vast uncertainty being placed on preference customers. Returning focus to the provision of net requirements priced at the actual cost incurred for said resources (as required by statute) is an essential step toward remediating these risks. Under a take-or-pay contract, the financial risk of system augmentation lies squarely with customers. If BPA (or a majority of its customers) determine they do not want to augment the Tier 1 system to meet these statutory obligations, then we ask that BPA create comparable terms and/or products for preference customers to acquire, integrate, and deliver self-supplied resources instead.

Thank you for the consideration of our positions. We look forward to the continued dialogue.

Roger Gray, President & CEO
PNGC Power

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[2] 1. WA Energy Strategy (2021) :https://www.commerce.wa.gov/growing-the-economy/energy/2021-state-energy-strategy/
2. E3 Power Replacement Study (2022): https://www.whitehouse.gov/wp-content/uploads/2022/07/E3-BPA-LSR-Dams-Report.pdf

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