DIRECT TESTIMONY OF

HARNEY ELECTRIC COOPERATIVE INC.

WITNESS: Fred Flippence

SUBJECT OF TESTIMONY:

New Resource Rate Design, and NT Billing Determinant

January 30, 2025

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q: Please state your name and qualifications.

A: My name is Fred Flippence. I am the General Manager of Harney Electric Cooperative Inc. ("HEC"). My qualification statement can be found at BP-26-HE-01.

Q: What organization is sponsoring this testimony?

A: I am submitting this testimony on behalf of HEC concerning a new cooperative member, the Thacker Pass Project ("TPP").

Q: What is the purpose of your testimony and how is it organized?

A: The purpose of this testimony is three-fold, and is organized as follows:

(1) To provide some background on HEC and its New Large Single Load ("NLSL"), the Thacker Pass Project, which will be served by HEC with firm power supplied by Bonneville Power Administration ("BPA");

(2) Identify what I believe are some rate making issues in terms of the development and design of the NR rate; and

(3) Identify what I believe are important and necessary modifications to the calculation of the Network Transmission billing determinant.

II. INTRODUCE HEC AND ITS CUSTOMER, THE THACKER PASS PROJECT

Q: Please provide an overview of Harney Electric Cooperative.

A: HEC is headquartered in Hines, Oregon. The HEC service territory is located in the Columbia River Basin and part of BPA's legislated service territory at the farthest southeastern edge.[1]

HEC was founded in 1954 to provide power to farmers and ranchers. HEC is an electric transmission and distribution cooperative serving over 20,000 square miles in southeastern Oregon and northern Nevada including the counties of Harney, Malheur, Deschutes, Crook, Humboldt, and Lake. HEC operates and maintains over 400 miles of transmission line, 2600 miles of distribution line, and approximately 4,000 meters.[2]

HEC purchases power from BPA, and under the Regional Dialogue Power Sales Agreement is a Load Following customer. HEC is typically operated as two systems. The north system is connected directly to BPA and a part of the BPA Balancing Authority Area, however, HEC's south system is located in and connected to Nevada Energy's ("NVE") service territory and Balancing Authority Area. This arrangement requires HEC's south system load to be served using BPA's transfer service.

Q: Please provide an overview of HEC's customer, the Thacker Pass Project.

A: The Thacker Pass Project ("TPP") is a lithium mine that is expected to start operations at the tail end of HEC's Regional Dialogue Agreement term. TPP is owned and being

[1] https://www.bpa.gov/-/media/Aep/about/publications/maps/bpa-servicearea.pdf
[2] https://hec.coop/about-hec-0

developed by Lithium Nevada LLC ("LN"), a joint venture between Lithium Americas Corp. ("LAC"), which has 62% ownership, and General Motors Holdings LLC which has a 38% ownership[3].

Due to an expectation that TPP's net load will grow to at least 10 aMW over its initial 12-consecutive months (BPA's NLSL threshold), HEC, in consultation with LAC elected firm Federal power under BPA's New Resources ("NR") Rate to serve TPP's net load. This decision was done after significant conversation with BPA.

While the portion of HEC's invoices that are specifically associated with serving TPP's power and transmission services will be directly passed on to TPP, HEC has an obligation to secure the correct services and the appropriate price of those services. In this case, and in particular, the price of power from BPA, i.e., the NR rate, is significantly different than what we anticipated, which is the primary reason to file this testimony.

Q: *Please explain a bit more about power service to HEC's south system.*

A: As mentioned above, HEC's service territory is in two Balancing Authority Areas. The south system is located in and connected to NVE's Balancing Authority Area. However, as a BPA customer due to our location in BPA's service territory, service to the south system requires transmission service over third-party transmission systems. The path that BPA has used to deliver power to Winnemucca, HEC's Point of Delivery for its south

[3] Lithium Americas Announces Closing of Thacker Pass Joint Venture with General Motors

system, requires the following: BPA's Network segment; BPA's Southern Intertie; rights to PacifiCorp's equipment at Malin; and a leg of NVE transmission (Hilltop – Winnemucca).

HEC's south system is sized to its load and currently has a power flow limitation of about 35 MW. With the addition of the TPP load, it is clear that under certain TPP operational conditions, this limitation could be violated. As a result, HEC required LN to invest in power management systems, load shedding systems, and protection relay equipment in order to ensure that HEC's system limitations are met. As a customer of BPA, HEC shared the engineering designs and explanations of these systems with BPA engineers, and has made them available to NVE. By sharing this information, HEC wanted to assure the affected transmission systems that the controls that will be in place will protect not only HEC's system, but the systems to which HEC is connected.

Q: Before you discuss your concerns with respect to BPA's rate proposal, please provide a bit more background on the Thacker Pass Project.

A: The TPP is a volcano-sedimentary lithium resource deposit mine located in the McDermitt Caldera on Bureau of Land Management property in Humboldt County, Nevada. In January 2025 Thacker Pass became the largest measured lithium resource and reserve in the world.[4]

[4] https://lithiumamericas.com/news/news-details/2025/Lithium-Americas-Increases-Mineral-Resource-and-Reserve-for-Thacker-Pass/default.aspx

The TPP is an exciting discovery, purposefully explored in 2007. Since that time, it has gone through the necessary reviews, studies, Records of Decisions, permits, and agreements to achieve its status today which is having completed over 80% of excavation, and over 50% of engineering.

It is an important load, given the growing need for electrification. Obviously, the load is immobile; the mine has an anticipated long-life; and currently, there is a lack of power and transmission infrastructure in the immediate area, which makes it important to develop resources co-located to the load.

Q: Is the TPP mine forecast to be a long-term load?

A: Yes. What I understand from the most recent information provided by LAC is that Phase 1 is expected to produce approximately 40 ktpa (kilo tonnes per annum) of lithium carbonate. In the latest Technical Report filed by LAC with the Securities and Exchange Commission, TPP is anticipated to produce approximately 160 ktpa of lithium carbonate with an 85-year Life of Mine[5]. Each phase is expected to support lithium needs for 800,000 electric vehicles/annually.

Domestic supplies of the critical mineral, lithium, are important to the U.S., and the TPP has a unique geology with significant locational benefits that make for a long-term and cost-effective operation. TPP's production costs rank very favorably in terms of

[5] https://s203.q4cdn.com/835901927/files/doc_presentations/2025/01/Technical-Report-December-2024.pdf

Benchmark Mineral Intelligence (Q1 2024). Also, TPP is utilizing well proven technology and equipment. In fact, LAC's Lithium Technical Development Center, located in Reno, Nevada, is now engaged in process optimization and beneficial uses of byproducts.[6]

To underscore the long life of TPP, recent estimates of mineral resource and reserve indicate Proven and Probable mineral reserves of 14.3 million tonnes of lithium carbonate equivalent, at an average grade of 2,540 parts per million, as well as Measured and Indicated mineral resource estimates of 44.5 million tonnes at an average grade of 2,230 parts per million.[7]

I have submitted forecast loads for TPP's first four Phases at least annually, and now on a more frequent basis to both BPA and NVE. All phases are same-sized and include same-sized steam-turbine generators ("STGs"). The new Technical Report also added a fifth phase to the project to maintain production later in the mine life.[8]

Each phase of operation is forecast to require about 60 aMW of power, of which 40 percent (25 aMW) will be served with co-located resources, and the remaining 60 percent (35 aMW) with imported power. The mine load will have a high load factor --



[6] LAC-Corporate-Presentation-November 2

[7] https://lithiumamericas.com/news/news-details/2025/Lithium-Americas-Increases-Mineral-Resource-and-Reserve-for-Thacker-Pass/default.aspx

[8] https://lithiumamericas.com/news/news-details/2025/Lithium-Americas-Increases-Mineral-Resource-and-Reserve-for-Thacker-Pass/default.aspx

approximately 95 percent. Due to TPP being located in HEC's south system, it is required to participate in the Energy Imbalance Market ("EIM") as an NVE resource. However, the STGs will be non-participating resources, as the output is specifically dedicated to the mine load.[9]

Q: *How will the lithium produced at TPP be used?*

A: The lithium produced at the mine is expected to be used primarily in electric vehicle batteries and potentially for grid storage to support large scale intermittent resources including solar and wind generation. The interest in TPP indicates the "strategic importance in creating a domestic supply chain for critical minerals". [10]

Q: *What sort of process is LN using to extract the lithium?*

A: LN is employing sustainable mining techniques using a newly developed chemical process. Block mining with concurrent reclamation is utilized which means that previously excavated mining sections are backfilled and reseeded as the operation progresses. Part of the chemical process involves mixing the clay deposit with water after which the clay slurry is combined with sulfuric acid in order to extract lithium. The production of sulfuric acid is accomplished on site by converting trucked-in sulfur (which is safer and one third the volume of transporting sulfuric acid). This process causes an

[9] HEC's LaRC submittals (confidential).
[10] https://lithiumamericas.com/news/news-details/2024/Lithium-Americas-Closes-2.26-Billion-U.S.-DOE-ATVM-Loan/default.aspx; Unlocking Thacker Pass: General Motors to Contribute Combined $625 Million in Cash and Letters of Credit to New Joint Venture with Lithium Americas

exothermic reaction, which provides the heat source, captured as steam, and converted into electricity using behind- the-meter STGs.[11] These STGs, or behind-the-meter generation using BPA terminology, are expected to serve about 43 percent of the mine's electrical needs, and each phase of development will have its own STG.[12] The remaining power requirements are being purchased from BPA as Federal power priced at the NR rate.

The TPP is designed so that it is a low water and carbon operation. Each drop of water that enters the process is recycled and reused an average of seven (7) times. In addition, the system design is a zero liquid discharge facility thus eliminating the production of any wastewater. [13]

Q: What about LN's financial viability?

A: Given the investments that both General Motors and the U. S. Department of Energy have made in TPP, I believe that its financial viability is solid. However, having solid financials also means that HEC and TPP are dedicated to making operations for both of our systems as efficient, reliable and cost-effective as possible. As earlier mentioned, this is why HEC is engaged in this proceeding.

[11] Thacker Pass Project Tech Center Presentation (confidential materials).
[12] Evidenced by HEC's load forecasts submitted to BPA through the LaRC process.
[13] Thacker Pass Project Tech Center Presentation (confidential materials).

More specifically, in 2023, General Motors ("GM") and Lithium Americas Corporation ("LAC") established an offtake agreement for up to 100% of TPP Phase 1. In late 2024, this relationship further evolved resulting in a joint venture between the companies and extending the offtake agreement to 20-years. GM owns 38% of Phase 2 production and retains its right of first offer on the remaining Phase 2 production volumes.[14] In total, GM has injected approximately $945 million into LAC.[15]

And then in October 2024, LAC closed a $2.26 billion, 24 year loan from the U. S. DOE under the Advanced Technology Vehicles Manufacturing Loan Program. [16]

III. THE NEW RESOURCES RATE

Q: Please briefly summarize BPA's proposed power service for HEC's TPP load.

A: Utilities serving NLSLs have rights to elect Federal service priced at the NR rate or work with their NLSL to secure Non-Federal power supplies. HEC elected to serve the TPP load at the NR rate for the balance of the Regional Dialogue Power Sales Agreement term. As a load following customer of BPA, HEC's election of Federal power from BPA for its NLSL will be a load following product and priced at BPA's New Resource (NR) rate.

This service is expected to commence not earlier than the end of Fiscal Year 2026 as pre-commercial operations. Once operations commence, which are expected to commence in

[14] Lithium Americas Announces Closing of Thacker Pass Joint Venture with General Motors
[15] LAC-GM Joint Venture
[16] Lithium Americas Closes $2.26 Billion U.S. DOE ATVM Loan

2027, BPA will start the NLSL evaluation. It is highly probable that TPP will qualify as a NLSL within the first 12 months of purchasing service from BPA. Also, HEC will identify the STGs that are serving approximately 40 percent of mine load as Consumer-owned Resources for each of the Phases of operations.

It is noteworthy that the proposed NR rate is significantly higher than HEC and the region expected, and certainly higher as compared with market purchases. Also, while BPA had proposed to directly assign transfer service costs under the Provider of Choice power sales agreements (PSA), I am surprised and disappointed that Staff has proposed including transfer service costs in the NR rate during the Regional Dialogue PSA period.

Q: What are your specific concerns with respect to the calculation of the NR Rate?

A: Two major concerns: (1) the resources assumed to serve the load; and the proposed direct allocation of transfer service costs.

a. <u>Resources Assumed to Serve the 7(f) Load</u>

Q: What are your concerns with the NR rate resource?

A: I understand that the BP-26 rate period will be the first Regional Dialogue rate period during which BPA is obligated to actually supply power at the NR Rate, and my concern is focused on the NR-26 Energy Charge.

Q. Did BPA explain how the proposed NR-26 Energy Charge was derived?

A. Mathematically yes, very clearly. However, the assignment of New Resource costs to the 7(f) rate does not appear to follow the principle of cost causation, which is fundamental to BPA rate-making.

Q. Please be more specific.

A. As I understand, for BP-26 New Resources costs include both pre-BP-26 New Resources as well as the newly created classification of purchases called "Other Augmentation".[17] This means "existing" New Resources cost and Other Augmentation cost is lumped together as the BP-26 New Resources total cost of service. In the Rate Analysis model, BPA then allocates this combined New Resources cost across 7(b), 7(c) and 7(f) loads without differentiation as to the origin/cause of the underlying New Resource.

Q. How does this treatment contradict the principle of cost causation?

A. On two levels. Put simply, all of the BP-26 New Resources except Other Augmentation existed in BPA's resource portfolio long before the new emergence of 7(f) load. There is no causal link between the BP-26 7(f) rate pool and those older resource costs.

In addition, Staff state that the presence of 7(f) load in the BP-26 rate case "led us to review the RAM2026 model for any refinements that might be needed to ensure rate directives are followed and cost causation principles remained consistent across all rate pools. In doing so, we determined adding a designation for Other Augmentation tightens the model's functionality to remain aligned with the statutory steps…In simple terms, Other Augmentation ensures the cost forecast associated with that resource is

[17] RAM2026 Initial Proposal Public Release excel file. Tab "ProgCOSA", and tab "NR-EX_Allocation".

appropriately allocated to the rate pool(s) that it serves." [18] The bucketing of Other Augmentation with older New Resources and allocation of that combined cost across rate pools defeats this purpose. Instead, it allocates this cost to 7(b) and 7(c) rate pools as well. At the same time, it allocates resource New Resources costs unrelated to 7(f) load into the 7(f) rate pool.

Q. *Is forecasted 7(f) load the only cause for Other Augmentation amounts in BP-26?*

A. No. The 7(f) load forecast averages 18aMW over the rate period, while the total Other Augmentation forecast (including 7(f) load) averages 29aMW over that same period. The difference reflects other requirements that BPA associates with the need for Other Augmentation, though, 7(f) load is a primary contributor.

Q. *So in terms of Other Augmentation as a New Resource, what are you proposing?*

A. I propose that Other Augmentation be tracked as its own cost item in New Resources. This would then allow simple allocation of that cost item first to the load most causing it, then to other loads. In other words, Other Augmentation resource costs would first be allocated to 7(f) load, with surplus, if any, then allocated to other load pools. As a result, the 7(f) load pool would first be served with Other Augmentation resources, and any shortfall then met with other New Resources.

Q. *Do you believe this approach to be just and reasonable?*

[18] BP-26-E-BPA-13 at 6: 9-25.

A. I do. I think it aligns much better with the principle of cost causality than Staff's proposal does and follows clearly and logically from Staff testimony.

Q. Do you believe this approach is consistent with Federal statute?

A. Yes. This approach better aligns with Federal statutes and is consistent with BPA's rate-making policies and principles.

b. Direct Allocation of Transfer Service Costs

Q: What are your concerns about the direct allocation of transfer service costs?

A: In the Initial Proposal, transfer service costs make up 9.55 percent of the NR rate; $5,280,000 over the BP-26 rate period. [19] As detailed below, the proposed transfer service costs include transmission service on three systems, losses on three segments, and ancillary services on NVE's system. Additionally, TPP will be charged for BPA NT service, including Ancillary Service Schedules 1 (Scheduling Control & Dispatch), 3 (Regulation and Frequency), 5, (Operating Reserves - Spinning) 6 (Operating Reserves (Supplemental), Regional Coordinator Service, and Losses. In sum, BPA's Initial Proposal is to charge HEC for transmission service required for TPP on four systems.[20]

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[19] BP-26-E-BPA-01A, Table 2.5.3, line 30.
[20] PN-BPA-38-6

Costs of Transfer Service

	Transmission Service	Ancillary Services Schedules 1, 3, 5, 6	Losses	Total	
FY 26 (based on 7 aMW load)					
BPA Intertie	$120,000		$100,000		$220,000
PacifiCorp	$10,000		$20,000		$30,000
NV Energy	$205,000	$30,000	$100,000		$335,000
				Total:	$585,000
FY 27 (based on 19 aMW load)					
BPA Intertie	$455,000		$280,000		$735,000
PacifiCorp	$25,000		$40,000		$65,000
NV Energy	$615,000	$90,000	$300,000		$1,005,000
				Total:	$1,805,000
FY 28 (based on 26 aMW load)					
BPA Intertie	$440,000		$385,000		$825,000
PacifiCorp	$30,000		$50,000		$80,000
NV Energy	$1,215,000	$175,000	$595,000		$1,985,000
				Total:	$2,890,000
			Rate Period Total:		$5,280,000

NVE Energy: 3.0% Real Power Losses
BPA Intertie: 3.0% Real Power Losses
PacifiCorp's costs are based on a proportional share of a contract rate.

Q: Why does BPA have transfer service in its power rates?

A: While it is clear that transfer costs are transmission costs, BPA has a long-standing practice of including third-party transmission costs in power rates. In BPA's Provider of Choice Fact Sheet which describes the history of transfer service, the genesis of the practice is explained as follows:

> "To fulfill its obligation to deliver federal power to its preference customers, the agency had to either build transmission to connect to customers, or contract with third-party transmission owners to use their systems to deliver federal power to the customers' loads. As more and more public utilities requested power from BPA, the need for additional transmission continued to grow, and the agency had to decide how it would serve the new customer loads…In many instances [determining the best plan of service] BPA's evaluation revealed that existing third-party transmission facilities could accommodate preference customers' loads in a more timely and cost-

> effective manner than building duplicate facilities connecting customers directly to BPA's system. In these instances, BPA decided to use transfer service to meet its obligation to deliver federal power to preference customers…As of 2020, 83 of BPA's 134 customers with long-term power sales agreements had at least one transfer point of delivery, and 55 customers were served solely by transfer service. In 2019, BPA's transfer service annual budget was approximately $90 million."[21]

HEC "is a firm power customer entitled to preference and priority under BPA's applicable statutes."[22] TPP is a part of HEC's preference load. BPA has an obligation to deliver federal power to its preference customers. I believe that BPA's proposed treatment to directly assign transfer costs to HEC for its NLSL (TPP) load is inconsistent with the history and purpose of transfer service, violates the Regional Dialogue Power Sales Agreement goal "to maintain transfer service rules and cost allocations that are comparable between transfer-served and direct-connected customers"[23]; and introduces serious concerns with respect to non-comparable transmission treatment. I also question the proposal to allocate four charges, i.e., two segments of BPA transmission, PacifiCorp, and NVE. The transfer costs, at least under the Regional Dialogue, should be shared among all BPA's preference load. I think that the direct assignment proposal is discriminatory.

Q: Is HEC's reliance on transfer service for its south system caused by the addition of the TPP load?

[21] https://www.bpa.gov/-/media/Aep/about/publications/fact-sheets/fs-202009-History-of-transfer-service.pdf
[22] PN-BPA-38-7.
[23] BP-26-E-BPA-16 at 4: 8-25.

A: No, however, Staff suggested that being the case.[24] It is correct that TPP is a new load on HEC's south system that requires transfer service, however, the Network Integration Transmission Service Agreement between BPA and NVE for HEC's south system includes existing load as well as TPP. The HEC south system has relied upon transfer service from NVE since 1979.

Q: Is the proposed direct assignment of transfer costs to HEC for service to the TPP load similar to other transfer service customers?

A: No. Staff describes its proposed rate treatment is "a matter of first impression" due to there having been no discussion about the cost treatment for transfer service for a NLSL. Staff also indicated that transfer service policies have been focused on BPA's "general requirements" customers – those eligible to be served with power at the PF rate. [25]

While I am not a lawyer, I understand BPA's point that it has never before addressed the cost treatment of transfer service for an NLSL. However, it seems that Staff could have drawn upon existing policies, precedent, and fairness for guidance, rather than choosing to penalize HEC's NLSL by directly assigning transfer as well as interim systems' transfer costs. In fact, my Regional Dialogue Power Sales Agreement, which is in place through September 2028, prohibits BPA from allocating interim system transfer costs to HEC.

Importantly, the Agreement Regarding Transfer Service ("ARTS"), which was in effect until September 30, 2024 (and arguably provides guidance through the term of the

[24] PN-BPA-38-7.
[25] PN-BPA-38-10

Regional Dialogue Agreement), requires an important equivalency standard, i.e., "BPA customers receiving deliveries via Transfer Service have expressed their desire for delivery of wholesale power to load at rates and on terms and conditions of service equivalent to the rates and terms and conditions of service available to public power utilities Directly Connected to BPA's main grid."[26]

The ART's Principles for Treatment of Other Cost Categories including transmission service, Ancillary Services, Costs not identified as of the effective date of the Agreement, Congestion Costs, Expansion costs, and in Section 9, Losses direct all to be allocated in a manner that reflects comparable treatment between those customers requiring Transfer Service and those customers Directly Connected.

In fact, in response to a request for an explanation of the underlying rationale for BPA providing comparable treatment between transfer-served and direct-connected customers, Staff indicated that "BPA has a general policy of supporting customers served by transfer service over third-party transmissions;" [and] "This support comes in various forms, such as managing the transmission agreements on the third-party transmission system;" [and] "BPA is also obligated to initially pay for transfer service under the Regional Dialogue Contract."[27] It is quite difficult to reconcile these policy positions with BPA's proposed treatment in BP-26 for the one NLSL that elected firm Federal power. HEC's south system loads have no option but transfer service. Moreover, when discussing with BPA when considering an NR service election, only one leg of transfer service was

[26] PN-BP-38-7, item 6.
[27] PN-BPA-38-8.

contemplated, however, now Staff propose to directly assign **three** Transmission Providers' services in addition to NT service.

Q: Does BPA directly assign transfer service costs to any other customers?

A: No. All transfer costs that are incurred as a result of service to PF 7(b) loads are allocated to that rate pool and are shared among all who purchase power from that rate pool, whether the individual customers require transfer service or not. Staff's testimony in this proceeding is that directly assigning the transfer service costs to different rate pools "better aligns the cost of the transfer services with the rate pool that receives the benefit."[28] This makes no sense. Transfer costs are an Agency decision. The only reason why HEC's south system and the NLSL that is located in HEC's south system are subject to transfer costs is because BPA chose to forego expanding its transmission system in a manner to ensure direct connection. This cost-saving measure for all BPA customers using transmission services should not result in the direct assignment of transfer costs. Moreover, if the transfers were treated as transmission costs, I believe that this treatment would be found to be in violation of the Federal Energy Regulatory Commission's ("FERC") comparability standard, due to BPA not treating customers comparably for the same service.

Q: Does BPA rely on statutory guidance for its proposal to directly assign transfer costs?

A: No. In fact, Staff has relied on statutory guidance to justify its proposal to roll-in Delivery Charge costs into BPA's Transmission Network segment, however, that

[28] PN-BP-38-11; BP-26-E-13 at 12; 6-12.

guidance has been ignored with respect to its decision regarding transfer service cost assignment. When asked about this contradiction, Staff refers to a statutory rate directive to justify its treatment of transfer service costs. However, that referenced directive does not apply – that directive focuses on limitations imposed on customers purchasing **power** priced at the NR rate having rights or no rights to Federal Base System Resources generation.[29] Staff also takes the position that "nothing in the Regional Dialogue contract or related policies calls for any particular rate treatment for the Transfer Services costs of an NLSL." In other words, Staff can choose whatever it wishes.[30]

That response does not, however, explain away how Staff can rely upon statutory directives and policies for one purpose and do the opposite for another. For justifying the treatment of the Delivery Charge costs, BPA relies upon the rate directive to encourage widest possible diversified use of electric power at lowest possible rates remaining consistent with sound business principles, and considering basic ratemaking principles (including cost causation).[31] Applying these same principles to its treatment of transfer service costs for TPP would justify a different approach.

Q: *Please contrast the impact the transfer service costs have on the NR rate with the impact on the PF rate.*

A: The transfer service costs in the NR rate equate to a unit cost of $11.80/MWh, for BP-26 and 9.55 percent of the NR rate.[32] The transfer service costs allocated to PF equate to a

[29] Regional Power Act (PL 96-501), Section 7.(f), 16 U.S.C. Section 839e(f).
[30] PN-BPA-38-10; BP-26-E-BPA-16 @ 12: 20-24.
[31] BP-26-E-BPA-23 @ 8: 9- 9:25.
[32] BP-26-E-BPA-01A, Table 2.5.3, line 30.

unit cost of $1.44/MWh and 3.53 percent of the "Net Power Cost to All PF".[33] If BPA allocated all transfer service costs to all forecast federal power sales to preference customers, regardless of service election, the unit cost of GTA would increase to $1.46/MWh, increasing the PF rate by 0.0465 percent and reducing the NR rate by 8.37 percent. I do not work with the various BPA rate models, however, using the referenced information, below is my analysis of the impacts.

Proposed BP-26 (average annual)	
Net Power Cost to All PF	$2,632,820,000
Portion of Costs Associated with GTA	$92,899,000
GTA Unit Cost	$1.44/MWh
Energy (MWh)	64,506,000
PF Average Net Cost	$40.82/MWh
Total Allocated Costs to NR	$18,424,000
Portion of Costs Associated with GTA	$1,760,000
GTA Unit Cost	$11.80/MWh
Energy (MWh)	149,200
NR Average Net Cost	$123.48/MWh
Shared GTA Costs Between PF and NR	
Total Costs Associated with GTA	$94,659,000
Total Energy PF and NR (MWh)	64,655,200
GTA Unit Cost	$1.46/MWh
Cost shift between NR and PF	$1,542,728 shifted to PF
Adjusted PF Average Net Cost	$40.839/MWh (+0.0465 percent)
Adjusted NR Average Net Cost	$113.17/MWh (- 8.37 percent)

[33] BP-26-E-BPA-01A, Table 2.3.4.1.2, lines 59 and 61; RAM2026 Initial Proposal Public Release, Unbifurcated PF, line 11, Net Power Cost to All PF.

IV. NT SERVICE

Q: Please briefly summarize BPA's proposed transmission service.

A: As a NT customer, HEC's billing determinant is based on HEC's Network Load. During conversations with BPA staff around the time that HEC elected NR service for TPP, it was made clear that BPA was relying on FERC Order 888 to define Network Load, i.e., load during the same hour of BPA's transmission system peak, ***and*** the generating output of behind-the-meter resources dedicated to load during that same hour. When questioning the approach, the options that BPA suggested included using the Short-Distance Discount ("SDD"), seeking modifications to the SDD, or seeking a change to BPA's Tariff definition of Network Load. Unfortunately, none of these are reflected in BPA's Initial Proposal.

Q: Why is BPA's approach an issue?

A: First, BPA's determination of net load is different between power and transmission business lines.

Speaking for the portion of HEC's south system that includes the TPP load, BPA's billing determinant for Power is based on net load; this is also the case for certain ancillary services, such as Regional Compliance. [34] As I understand, the load upon which BPA's Resource Adequacy Capacity obligation will also be based on net load and logically the associated transmission needed for the Resource Adequacy capacity will be based on net load.

[34] BP-26-E-BPA-16 at 5-10; 1-23. [PN-BPA-38-2]

For other Transmission services such as Network Integration services, BPA still proposes to charge for Network Load or "total load", meaning load plus generating resources serving that load. BPA "discounts" the cost of using local resource generation that utilizes less than 75 miles of the BPA transmission system. However, BPA limits the discount to 40 percent of the generating resource serving the load. This means that a customer using no (zero) BPA transmission system for a behind-the-meter resource using none of the BPA transmission system, is nonetheless charged 60% of the output of the resource. In the case of TPP, about 40 percent of the mine load will be served with behind-the-meter generation, however, the current SDD limits the discount so the TPP load will still be charged for 15 MW (15/25 MW) of transmission it is not using. Put simply, BPA is charging HEC for transmission service that its customer TPP physically cannot and therefore will not use. In addition, and as earlier discussed, BPA proposes to not only charge for services not rendered for NT service, but also apply the same erroneous billing determinant to the three legs of transfer service.[35] The combination of these rate design elements raise serious questions about the appropriateness of BPA's Initial Proposal, and is contrary to recent FERC policy. [36]

Second, as a transfer customer and subject to NVE's EIM requirements, BPA schedules service over NVE's system, and the TPP will be required to submit generation forecasts for its STGs. It seems contrary to common sense to base the NT Billing Determinant on load plus generating output, when BPA and NVE will have all of the forecasts, schedules and metering data to determine TPP's net load.

[35] PN-BPA-38-6.
[36] 178 FERC ¶ 61,086, February 11, 2022.

Finally, if actual use of transmission service is less than BPA's NT billing determinant, it could market that available transfer capability.

Q: Is BPA aware of the behind-the-meter generation that TPP is developing?

A: Yes. BPA is well aware of the power flow limitations on HEC's south system. BPA is also aware that TPP is constructing a like-size steam-turbine generator for each of its mining phases. BPA is also aware that TPP has developed Power Management Systems, Load Shedding Systems, and Protection Relay equipment to ensure that HEC's system limits and behind-the-meter generation will not flow over HEC's grid, NVE's transmission system, or BPA's. In fact, HEC solicited review from BPA engineers, and the response indicated neither interest nor concern:

> "With regards to the proposed load shedding scheme, BPA Transmission Planning has reviewed the documentation that was shared with us and has no comments or questions at this time. Transmission impacts of the load and the load shedding scheme will primarily be borne by Harney Electric and Nevada Energy facilities, and BPA does not anticipate issues with its facilities in the area. The load shedding scheme does not appear to require direct communications with BPA's facilities at Nevada Energy's Winnemucca Substation, so we do not foresee the need for additional technical requirements. Please let us know if you have any other questions or specific points of concern we should address." (BPA's Transmission Planning Group, May 7, 2024).

As a result, BPA is aware of the innovative investments that TPP is making to ensure operational integrity for HEC, NVE, and BPA, but it seems that these system benefits are ignored when it comes to rate-making. When asked about the customers whose SDD-qualifying resources do not use adjacent transmission systems, or have made investments to limit power flows on adjacent systems, Staff's response is that it "did not perform the requested analys[e]s for BP-26 Initial Proposal."[37] BPA's proposal to calculate the NT billing determinant based on total load, not net load, is not only disappointing, but inefficient, and as noted above, contrary to FERC policy.[38]

Q: When did you share details with BPA rate Staff?

A: In March, 2024, HEC reached out to its Account Executives expressing interest in exploring modifications to the SDD – specifically suggesting that the discount should be 100 percent for behind-the-meter resources not using the BPA transmission system, and requesting from BPA acknowledgment of investments that manage loads and power flows. HEC heard back from BPA (May 16, 2024) and encourage HEC to present at a BP-26 Customer-led workshop.

HEC worked with Umatilla Electric Cooperative and Clatskanie People's Utility District who together sponsored one of the Customer-led workshops (July 11, 2024) leading up to BPA-26. The main points we made were:

(1) Enhance BPA's transmission planning and construction efforts as well as grid reliability by encouraging customers to locate resources near load.

[37] PN-BPA-38-3.

(2) Recognize recent decisions by the Federal Energy Regulatory Commission regarding the calculation of Network Load and specifically not charging for transmission service not used. (178 FERC ¶ 61,086, February 11, 2022)

(3) Establishing a uniform basis for making the SDD available to all NT customers regardless of service election.

(4) Provide a streamlines process for SDD resource siting and integration.

(5) Clarify and align definitions and treatment of Behind-the-Meter resources by both Business Lines, and as referenced in BPA's tariff, General Rate Schedule Provisions, Business Practices, etc.

Q: How was the customer-led workshop received?

A: The presentation seemed to be positively received. However, since that time, BPA indicated that it did not have time to accommodate the suggestion, but it sees "value" in the concept. Below is the excerpt from BPA's BP-26 workshop (August 27th):

– Short Distance Discount

• An examination of the Short-Distance Discount for NT service and PTP customers is something that we are not able to accommodate within the scope of BP-26. BPA does see value in the discussion and would be amenable to opening the subject in future rates cases. [39]

Q: Did you ask BPA to reconsider its decision?

[39] BP-26 Workshop, August 27, 2024, at 9. https://www.bpa.gov/-/media/Aep/rates-tariff/bp-26/Aug-27-28-Workshop/BP_TC-26-Aug-Workshop.pdf

A: After BPA's August workshop, HEC, LAC and representatives from the Pacific Northwest Generating Cooperative ("PNGC") met to familiarize BPA staff with the project. At that time we did engage with HEC's Account Executives and as a result, suggested a pilot program. This idea was pursued soon before BP-26 ex parte rules went into effect, and so BPA indicated that it did not have time to seriously consider the idea. That is why the concept has introduced through BP-26 Data Requests, i.e., whether Staff would be willing to consider a new Technology Pilot. Unfortunately, the response was that "BPA has not performed any analysis around offering an additional technology pilot for the purposes outlined in the data request [in lieu of increasing the Short-Distance Discount Credit to 100%]. As a result, BPA cannot answer the question of whether it would be willing to offer an additional technology pilot."[40]

Q: Why does BPA limit the Discount in the SDD to 40 percent?

A: When asked, Staff's response was effectively, this is how we have done it for many years. More specifically, BPA designed the discount for Point-to-Point transmission service when first included in the settlement of the 1996 rate case, and in the 2012 rate proceeding, when the discount was proposed for Network Integration Transmission Service. Staff indicated that its "initial proposal for the short distance discount in the proposed NT-26 rate schedule is to maintain the discount as formulated in current rates. Staff did not take any position or perform any analysis in the initial proposal with respect to potential alternatives."

[40] PN-BPA-38-5.

However, research into the genesis of this discount uncovers more regarding its initial purpose, which is important for BPA to reconsider, especially when the agency is faced with unprecedented expansion of its transmission system.[41] In the 2006 Final Transmission Proposal, the settlement language includes that "TBL [Transmission Business Line] agrees to work with interested customers to determine the most appropriate mechanism, if any, to recognize the contribution that local Network Resources make to the need for an adequate transmission system, and to determine whether a transition mechanism is appropriate for NT customers that currently serve Customer-Served Load (CSL) with such resources."[42]

In the 2008 Final Transmission Proposal, BPA adopted an early form of the SDD, as Declared and Actual Customer-Served Load which reduced the customer's Network Load by the Declared CSL, if for the billing month the Actual CSL during Heavy Load Hours [was] greater than or equal to 60 percent of the Declared CSL. While this discount impacted only the Base Charge, it still allowed for a credit based on the total Declared Customer-Served Load.[43]

And, then, in BP-12, BPA proposed the current form of the SDD, due to the expectation that the discount would encourage customers to locate resources close to load which "reduces use of the Federal transmission system and, therefore, reduces the need for transmission system expansion."[44] The need to encourage locating resources close to

[41] BP-20-E-BPA-25, at 6: 12.
[42] TR-06-A-01 at 2-3.
[43] TR-08-A-01 at 13-14.
[44] BP-12-E-BPA-35 at 5-7.

load is still valid, and could increase the amount of NT customer resources that qualify to beyond the BP-26 estimates of 96 MW.[45]

Moreover, for HEC and the TPP load, BPA's leadership on this issue could translate into NVE deciding that it is inappropriate to charge for services not rendered, and potentially relieve some congestion or enable use of freed-up ATC. It would be very positive if BPA rethink its position on charging transmission services for service not rendered.

Q: With respect to the SDD, what specific changes to its Initial Proposal do you suggest BPA adopt in BP-26?

A: I believe that BPA has two constructive options: (1) revise the SDD to allow up to a 100 percent credit for loads served with behind-the meter generation; or (2) adopt a Pilot program for NT customers that can demonstrate that they do not use the BPA or other Transmission Systems for behind-the-meter generation. BPA is, in our view, otherwise ignoring an opportunity to encourage intelligent behind-the-meter load/resource management. If not now, when?

Q: Do you have language for modifying the SDD?

A: Yes. The language presented during the Customer-led workshop on July 11th is attached as Exhibit 1 to my testimony.

[45] PN-BPA-38-3.

Q: Do you have language for a Pilot program for NT customers that can demonstrate that they do not use the transmission facilities (neither BPA nor transfer service utilities) for behind-the-meter generation?

A: Yes. Please see Exhibit 2 to my testimony.[46]

Q: Please quantify the impact of reducing HEC's NT billing determinant to reflect TPP's net load (by excluding behind-the-meter resource generation).

A: As earlier mentioned, about 40 percent of TPP's load will be served with its behind-the-meter resources. If the net load plus resource generation is used for the NT billing determinant, then each phase of TPP load will be charged for 60 aMW (the "total load", composed of 35 aMW of imported power plus 25 aMW of STG output). If the currently configured SDD is applied, the NT billing determinate will be reduced to 50 aMW. If the SDD enables full discount for resource generation, the NT billing determinate 35 aMW, so roughly a 40 percent correction to "total load".

Additionally, this could translate into a 40 percent reduction to the proposed directly assigned transfer service costs, depending upon the billing determinant that BPA uses for the Southern Intertie segment, the PacifiCorp segment, and the NVE transmission (between Hilltop and Winnemucca).

V. CONCLUSION

Q: Please summarize your testimony.

[46] See also PN-BPA-38-5.

A: I think that Staff has an opportunity to learn more about a BPA customer that is relatively small, remote, and yet managing some important and complicated circumstances. Maybe this insight will provide reason to make some modifications to the Initial Proposal, as suggested.

First, I encourage Staff to reconsider its "new resource" allocation to the NR rate. BP-26 is the first rate period during which the Agency will serve a load at the NR Rate. The 7(f) rate pool should first be allocated the cost of Other Augmentation that largely results from that new 7(f) load.

Second, BPA's transfer service policy under the Regional Dialogue Power Sales Agreement requires equal treatment between those loads that are directly connected and those loads requiring transfer service. BPA's proposal in BP-26 should be modified to treat transfer service costs as a shared cost among PF and preference NR loads.

Finally, we encourage BPA to modify is Short-Distance Discount so that resources that use less than 75 miles of the BPA transmission system enjoy up to a full discount. Alternatively, we recommend that BPA initiate a pilot program for the express purpose of demonstrating that the behind-the-meter generation is serving load internal to the customer's system, and due to neither scheduling nor utilizing Federal or non-Federal transmission facilities, should benefit by way of a NT billing determinant based on net load.

Q: Does that conclude your testimony?

A: Yes, thank you.