The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: **[NAME OF UTILITY]**
Docket No. ER26-____-000

Relevant State Entities' *Ex Ante* Cost Allocation Proposed Tariff Amendment

Dear Secretary Reese:

The Relevant State Entities (RSEs) for the NorthernGrid transmission planning region[1] submit this proposed amendment to the proposed tariff language filed with the Federal Energy Regulatory Commission (FERC or Commission) by the NorthernGrid transmission providers seeking to comply with Order No. 1920.[2] Order No. 1920 requires that the transmission providers in a region propose one or more *ex ante* cost allocation methodologies to apply to Long-Term Regional Transmission Projects (Projects) selected for development and cost allocation as part of a regional transmission planning process.[3]

Order No. 1920 also provides the RSEs in a transmission planning region an opportunity, if they can reach agreement, to propose one or more *ex* ante cost allocation methodologies.[4] If the transmission providers in a planning region do not agree to adopt the RSE proposed

[1] NorthernGrid RSEs include California Energy Commission, California Public Utilities Commission, Idaho Governor's Office of Energy and Mineral Resources, Idaho Public Utilities Commission, Montana Department of Environmental Quality, Montana Public Service Commission, Oregon Department of Energy, Oregon Public Utility Commission, Public Utilities Commission of Nevada, Utah Department of Commerce, Utah Office of Energy Development, Utah Public Service Commission, Washington Department of Commerce, Washington Energy Facility Site Evaluation Council, Washington Utilities and Transportation Commission, Washington State Office of the Attorney General, Wyoming Department of Environmental Quality/Industrial Siting Council, Wyoming Energy Authority, Wyoming Office of Consumer Advocate, and Wyoming Public Service Commission.

[2] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Order No. 1920, 187 FERC ¶ 61,068 (2024) (Order No. 1920), *order on reh'g & clarification*, Order No. 1920-A, 189 FERC ¶ 61,126 (2024) (Order No. 1920-A), *order on reh'g & clarification*, Order No. 1920-B, 191 FERC ¶ 61,026 (2025) (Order No. 1920-B).

[3] Order No. 1920 at P 1291.

[4] Order No. 1920 requires the RSEs to submit their *ex ante* proposal to the planning region no later than the conclusion of the State Engagement Period. Id. at P 1354.

ex ante methodology, the transmission providers must include their own *ex ante* methodology or methodologies in the compliance plan submitted to the Commission.[5] Order No. 1920-A, however, requires the transmission providers to also submit the RSE proposal for FERC to consider. [6] The RSE proposal must be submitted to the planning region by the end of the State Engagement Period.

The Committee on Regional Electric Power Cooperation (CREPC), which includes state utility regulators and state energy office officials throughout the West, formed an *Ad Hoc* Committee to help facilitate the RSEs' involvement in the NorthernGrid State Engagement Period. After more than a year-and-a half of Committee meetings (including numerous conversations with representatives from NorthernGrid) and analysis, on April 22 seven[7] of the eight states (with California abstaining) voted to submit the RSE proposed *ex ante* cost allocation methodology to NorthernGrid. On April 28 the RSEs submitted the tariff language associated with this proposal to the NorthernGrid Enrolled Parties. Representatives of NorthernGrid subsequently informed the *Ad Hoc* Committee that the NorthernGrid Enrolled Parties have decided to file their own *ex ante* cost allocation proposal but will also attach the RSEs' proposal to their compliance filings as required by Order No. 1920-A.

The ex ante methodology proposed by the NorthernGrid Enrolled Parties would allocate Long-Term Regional Transmission Project costs by calculating the total benefits[8] the Project is expected to produce and then apportioning those benefits based on the share of those benefits each Enrolled Party is expected to receive. The Project costs would then be assigned to the Enrolled Parties based on their respective shares of the Project benefits. For example, if a Project is expected to cost $100 million and produce $200 million in benefits and Utility A is expected to receive 40% of those benefits, Utility B is expected to receive 35% of those benefits and Utility C is expected to receive 25% of those benefits, Utility A will have to pay $40 million, Utility B would have to pay $35 million and Utility C would have to pay $25 million.

The RSEs believe that an *ex ante* cost allocation that relies entirely on apportioning benefits between FERC-jurisdictional transmission providers is less than optimal. For instance, some benefits are not as easily quantifiable as others, and it is not always easy to allocate some of these benefits between different transmission providers. After considerable thought and analysis, the RSEs developed a more diverse approach that can lessen some of the barriers to both transmission planning and cost allocation that plague the non-RTO West. The RSEs proposal would more accurately match benefits with beneficiaries and give the states in the NorthernGrid transmission planning region greater confidence that utility customers will pay their fair share of costs for new transmission, and not more.

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[5] Id. at P 1359.
[6] Order 1920-A at P 651.
[7] Washington, Oregon, Idaho, Utah, Nevada, Montana, and Wyoming.
[8] Based on the seven benefits FERC identified in Order No. 1920. Order No. 1920 at PP 740-823.

The RSEs' proposal relies on three separate steps to determine how the costs associated with Long-Term Regional Transmission Projects will be allocated: (1) A process allowing for entities to subscribe to and pay for transmission capacity associated with the Project; (2) An assessment of the total Project benefits and the apportionment of those benefits among the Enrolled Parties; and (3) the use of a separate zonal mechanism to assess which Enrolled Parties are responsible for energy flows on the Project.

The following is a brief description of the RSEs' cost allocation proposal:

Scope and Applicability

The RSEs are proposing a single cost allocation methodology that would apply to each Long-Term Regional Transmission Project (or portfolio of Projects) selected for the purposes of cost allocation pursuant to the requirements of Order No. 1920. The proposal would not apply to reliability or economic projects planned for and selected pursuant to the requirements of FERC Order No. 1000.[9]

Subscription Process

The Subscription Process would allow entities to acquire transmission capacity rights associated with the Project. After a Project Developer (or Developers) is selected, the Developer would have 90 days to establish a process enabling any interested entity (including investor-owned utilities, publicly-owned utilities, electric cooperatives, and electric generators) to seek to purchase transmission capacity associated with the Project.

Project Developers will be required to conduct the Subscription Process consistent with all applicable FERC requirements. In particular, the Developer will need to comply with the Commission's policies governing the allocation of capacity associated with new merchant transmission projects, including (1) broadly soliciting interest in the project from potential customers and (2) demonstrating to the Commission that that the solicitation, customer selection and negotiation processes were non-discriminatory.[10]

Following the open solicitation, the Project Developer would have 60 days to enter into and complete bilateral negotiations addressing the terms and conditions applicable to each party procuring transmission capacity. The negotiated terms must recognize material differences that do not result in undue discrimination or preferential criteria.[11] The negotiations will not, however, include pricing because each entity contracting for

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[9] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 136 FERC ¶ 61,051 (2011).

[10] *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects*, 142 FERC ¶ 61,038 (2013) at P 16 (Policy Statement). *See also*, *El Rio Sol Transmission Co.*, 188 FERC ¶ 61,007 (2024).

[11] Policy Statement at P 19.

transmission capacity will pay the same rate per unit of capacity as is allocated to Enrolled Parties pursuant to the post-Subscription cost allocation process.[12] The pricing rate will be determined by the Project Developer based on the cost of a project and the capacity of a project, and posted publicly in advance of the open solicitation to inform a potential subscriber's decision of whether to subscribe to a Project.

Post-Subscription Process

If the transmission capacity associated with the Project is not fully accounted for at the end of the Subscription Process[13], the remaining transmission capacity and the associated costs will be allocated as follows:

- For Projects with a voltage that exceeds 300 kV, 75% of the Post-Subscription Costs (total project costs less the amount committed during the subscription process)[14] will be allocated to the Enrolled Parties based on their share of seven Project benefits.[15] The remaining 25% of the Post-Subscription Costs would be distributed to transmission zones (as designated by NorthernGrid) based on the zones' anticipated proportional use of the Project during peak conditions by using power flow modeling pursuant to Solution-Based Distribution Factor (D-FAX) analysis.[16]
- For Projects with a voltage between and inclusive of 200kv and 300kv, 90% of the Post-Subscription Costs will be allocated to the Enrolled Parties based on their share of the

[12] This requirement is necessary to avoid the potential for Enrolled Parties engaging in bidding practices during the Subscription Process that might transfer additional costs to other transmission providers that do not participate in the Subscription Process.

[13] The RSEs' proposal allows for total Post-Subscription costs that must be allocated to be further reduced if, subsequent to the end of the Subscription Process, any entity volunteers to purchase additional capacity (at the same rate as is charged for capacity during the Subscription Process).

[14] For example, if 60% of the capacity of a $200 million Project is allocated pursuant to the Subscription Process, 40% of the capacity, $80 million, would remain to be allocated.

[15] These benefits are: (1) reduced loss of load probability or loss of planning reserve margin; (2) reduced production costs; (3) avoided or deferred reliability transmission facilities; (4) reduced transmission losses; (5) reduced congestion; (6) grid resilience; and (7) capacity cost reductions. NorthernGrid will add the total amount of these benefits and then determine the proportion of benefits allocable to each Enrolled Party. For instance, if the remaining costs (Post-Subscription) for a 350 kV Project are $100 million and Utility A receives 35% of the seven benefits, Utility A will be allocated $35 million during this step. Utility A's benefit apportionment would be additionally combined with any amounts Utility A is allocated pursuant to the zonal cost allocation approach.

[16] After the D-FAX analysis determine the power flows attributable to each zone, the Enrolled Party serving load in that zone would be allocated a proportionate share of the Project costs. If more than one Enrolled Party serves load in a zone, the proportionate share of costs attributable to that zone would be allocated to each Enrolled Party serving load in that zone based on their respective shares of the load within that zone. As an example: A D-FAX analysis concludes that a Project causes flows to two zones, Zone 1 (40%) and Zone 2 (60%). Utility A serves 100% of load in Zone 1, Utility B serves 80% of the load in Zone 2 and Utility C serves the remaining 20% of load in Zone 2. In this situation, Utility A would be allocated 40% of the zonal costs, Utility B would be allocated 48% of the zonal costs and Utility C would be allocated 12% of the zonal costs.

seven Project benefits. The remaining 10% of the Post-Subscription Costs would be distributed to transmission zones (as designated by NorthernGrid) based on the zones' proportional use of the Project during peak conditions by using power flow modeling pursuant to Solution-Based Distribution Factor (D-FAX) analysis.

- For Projects with a voltage less than 200 kV, 100% of the Post-Subscription Costs will be allocated to the Enrolled Parties based on their share of the seven Project benefits.

Allocation of Transmission Capacity Rights

The RSEs' proposal would assign remaining transmission capacity rights to the Enrolled Parties in proportion to their allocation of Post-Subscription Costs.[17] Consistent with Commission precedent,[18] any Enrolled Party that does not wish to utilize these transmission capacity rights may sell them to another entity.

Cost Allocation Associated with Portfolio of Projects

To the extent that the Enrolled Parties select a portfolio of Long-Term Transmission Projects for the purposes of cost allocation, the amount of Post-Subscription Costs allocated to any Enrolled Party could not exceed the sum of the amounts that would have been allocated to the Enrolled Party had those projects each been selected separately.

[17] For example: $200 million of a Project's costs and 400 MW of transmission capacity remains to be allocated following the Subscription Process. If, as part of the Post-Subscription Process, Utility A is allocated $60 million, Utility B is allocated $50 million, Utility C is allocated $30 million and Utility D is allocated $60 million, 120 MW of transmission capacity would be allocated to Utilities A and D each, 100 MW of transmission capacity would be allocated to Utility B, and 60 MW of transmission capacity would be allocated to Utility C.
[18] *Promoting a Competitive Market for Capacity Reassignment*, 132 FERC ¶ 61,238 (2010).

De Minimis Benefits

The RSEs' proposal includes an exception for the allocation of Post-Subscription Costs to Enrolled Parties that are determined to be receiving a *de minimis* level of benefits from a Long-Term Transmission Project. The RSEs' proposal would exempt an Enrolled Party from post-Subscription Cost responsibility if the Party's benefits (taking into account the seven benefits and the zonal cost allocation approaches described above) amount to less than two percent of all allocable benefits. Any Post-Subscription Costs that would have been allocated to an Enrolled Party but for this *de minimis* exception, would be allocated to the remaining Enrolled Parties in the same proportion of their Post-Subscription Cost allocations.[19]

The RSEs Proposal is Just and Reasonable

It is well-settled that the Federal Power Act requires that transmission costs must be allocated in a manner that is "roughly commensurate" with the benefits received.[20] The RSEs' Proposal adopts three different approaches, each of which ensures that the costs associated with Long-Term Transmission Projects that are selected for the purposes of cost allocation pursuant to Order No. 1920 are allocated to beneficiaries.

The proposed Subscription Process relies on transactions where an entity, in exchange for receiving transmission capacity, agrees to pay a set amount that is equal to the amount paid by all other entities receiving the same level of transmission capacity rights. The Commission itself, in Order No. 1920, permits voluntary contributions to pay-down the cost of a project before the remaining costs are allocated pursuant to other cost allocation methodologies.[21] Presumably, these voluntary payments could not be authorized but for the fact that such payments satisfy the requirement that costs be matched with beneficiaries.

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[19] For example, if Utilities A (capturing 60% of project benefits), B (capturing 25% of project benefits), C (capturing 14% of project benefits), and D (capturing 1% of project benefits) are deemed to be beneficiaries of a Project, and $100 million remains to be allocated Post-Subscription, the $1 million that would have been allocated to Utility D but for the *de minimis* provision would, instead, be allocated to Utilities A (in the additional amount of $606,000), B (in the additional amount of $252,500), and C (in the additional amount of $141,500).

[20] Order No. 1920 at P 1305; *see also* Order No. 1000 at P 10 ("[T]he principles-based approach requires that all regional and interregional cost allocation methods allocate costs for new transmission facilities in a manner that is at least roughly commensurate with the benefits received by those who will pay those costs"); *see also* Illinois Commerce Commission v. FERC, 576 F.3d 470 (7th Cir. 2009).

[21] Order No. 1920 at PP 1012-1018.

In addition, the bulk of the Post-Subscription Costs would be allocated by assessing each Enrolled Party's share of the same seven benefits that FERC identified for consideration as part of the Order No. 1920 planning process. This approach is plainly consistent with the requirement that costs be allocated in a manner roughly commensurate with benefits.

The RSEs' proposal also utilizes the Solution Based D-FAX methodology to identify beneficiaries and apportion those benefits based on a modeling of the expected energy flows on a proposed Long-Term Transmission Project. FERC has previously approved the use of the D-FAX methodology to, in part, match transmission facility benefits with beneficiaries[22] and that methodology remains useful for cost-allocation pursuant to Order No. 1920, particularly for benefits that are challenging to precisely quantify and apportion.

The RSE's Proposal is Superior to the Enrolled Parties' *Ex Ante* Cost Allocation Proposed Methodology

The Enrolled Parties are proposing to allocate costs solely by apportioning the costs associated with each selected Project among the Enrolled Parties based on the benefits that each would be expected to experience from the Project. While the RSEs do not contest that this methodology is consistent with requirements of the Federal Power Act, the RSEs believe their proposal, as outlined here, is superior.

RSEs are entrusted with ensuring that consumers in their states have access to electric service that is both reliable and affordable. Although regionally-planned transmission potentially offers substantial benefits, it is important that state-regulated utility customers pay only their fair share and not more. The RSEs' proposal is more likely to achieve this goal.

The states located in the NorthernGrid planning region are served by a variety of investor-owned, federally-owned, municipal, and cooperative electric utilities. The courts have made it clear that FERC's transmission planning and cost allocation authority only extends to FERC-jurisdictional transmission providers and non-jurisdictional utilities that consent to cost allocation associated with a regionally planned Project.[23] As a result, it is much more difficult for the NorthernGrid transmission providers to properly plan for the region's transmission needs, identify appropriate transmission projects, and select them for development and cost allocation. Although NorthernGrid cannot plan for the needs of non-jurisdictional utilities, if a Long-Term Transmission Project were to be selected, non-

[22] *PJM Interconnection, LLC*, 142 FERC ¶61,214 (2013); *order on reh'g and compliance*, 147 FERC ¶ 61,218 (2014); *order on reh'g and compliance*, 150 FERC ¶ 61,038 (2015); and *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

[23] *See e.g.*, El Paso Elec. Co. v. FERC, 75 F. 4th 483 (5th Cir. 2023).

jurisdictional utilities may also benefit from the project given how intertwined the transmission system is in the West.

By establishing a Subscription Process, the RSEs' proposal allows non-FERC jurisdictional entities as well as FERC-jurisdictional utilities an opportunity to voluntarily purchase transmission capacity rights and pay-down, in part, the costs of a Project without the pre-requisites of having engaged in planning or submitting to regional cost allocation. Such an approach might not work in a region served by an RTO where transmission capacity rights are not similarly assigned, however this is an approach that will work well in the western planning regions not served by CAISO or SPP.

Moreover, the RSEs' proposal recognizes that the matching of benefits with beneficiaries is not an exact science and that it is difficult to apportion some benefits to individual transmission providers with a great degree of certainty. While the RSEs' cost allocation proposal includes benefit apportionment, it recognizes the difficulty of exact calculations by including a subscription element and a zonal methodology to enhance confidence that Project benefits are being allocated to those that benefit.

The RSEs are focused on maintaining affordability for customers while also representing the interests of their states to ensure that regional transmission planning produces the best results. These interests require a regional transmission cost allocation methodology that ensures captive ratepayers in the region pay their fair share and no more. The RSEs believe that their proposal is more likely to produce that result.

Conclusion

For the reasons set forth in this letter and the attached tariff language, the RSEs respectfully request that the Commission approve the RSEs' proposed *ex ante* cost allocation proposal as applicable to the Long-Term Transmission Projects planned for and selected for the purposes of cost allocation pursuant to the requirements of Order No. 1920.

Respectfully submitted this 4th day of June, 2026,

Tammy Cordova

CREPC 1920 Ad Hoc Committee Co-Chair
Commissioner, Public Utilities Commission of Nevada

John S. Harvey, Ph.D.

CREPC 1920 Ad Hoc Committee Co-Chair
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