UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Implementation of Dynamic	)	
Line Ratings Advance Notice of	)	Docket No. RM24-6-000
Proposed Rulemaking	)	

Initial Comments of the R Street Institute

I. Issue Summary

On July 15, 2024, the Federal Energy Regulatory Commission (Commission or FERC) published an advance notice of proposed rulemaking (ANOPR) on the implementation of dynamic line ratings (DLRs) in the Federal Register.[1] This succeeds a Feb. 24, 2022, Notice of Inquiry (NOI) on the implementation of DLRs.[2] The NOI followed FERC order No. 881, which revised the *pro forma* Open Access Transmission Tariff (OATT) by requiring transmission providers (TPs) to adopt transmission line ratings that reflected ambient air temperature, or ambient-adjusted ratings (AARs).[3] Before initiating the ambient line ratings rulemaking, the Commission held a workshop on grid-enhancing technologies (GETs) that included, but was not limited to, ambient and DLRs. The problem statement on GETs policy is overwhelming, with billions in expected annual cost savings with a payback period of months on upfront costs.[4]

Transmission line ratings are determined, in part, by weather conditions. Before Order 881, TPs typically used static or seasonal line ratings based on infrequent potential weather conditions. This resulted in overly conservative assumptions relative to most real-time weather conditions. Thus, static and seasonal line ratings resulted in inaccurate line ratings under most circumstances, which increased system costs and inhibited market performance by reducing the gains from trade within and between regional transmission systems. To remedy this, R Street filed comments and met with FERC commissioners and staff in support of economical GETs policy via the GETs workshop and the rulemaking process leading to Order 881, as well as commended the Commission for issuing the order.[5]

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[1] 89 Fed. Reg. 14666 (July 15, 2024). https://www.govinfo.gov/content/pkg/FR-2024-07-15/pdf/2024-14666.pdf.
[2] Federal Energy Regulatory Commission, *Implementation of Dynamic Line Ratings*, Notice of Inquiry, Docket No. AD22-5-000, Feb. 24, 2022. https://www.govinfo.gov/content/pkg/FR-2022-02-24/pdf/2022-03911.pdf.
[3] Federal Energy Regulatory Commission, *Managing Transmission Line Ratings*, Final Rule, Docket No. RM20-16-000, Order No. 881, Dec. 16, 2021. https://www.wrightlaw.com/62D00A/assets/files/documents/W0284102.PDF.
[4] See, e.g., T. Bruce Tsuchida et al., "Unlocking the Queue with Grid-Enhancing Technologies," The Brattle Group, Feb. 1, 2021, p. 11. https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf.
[5] "Comments of the R Street Institute before the Federal Energy Regulatory Commission on Post-Workshop Comments on Grid-Enhancing Technologies," Docket No. AD19-19-000. https://www.rstreet.org/wp-content/uploads/2020/02/FINAL-Hartman-GETs_Post-Workshop_Comments.pdf.

R Street's positions on GETs, and those of numerous transmission consumer groups, were buttressed by an R Street paper that reflected input from a convening of national transmission consumer groups.[6] The paper identified optimization of the existing transmission system, with an emphasis on GETs, as one of four principles for consumer-led transmission reform. R Street is coordinating with some of these groups on this proceeding and is in the process of reconvening the groups to update the consumer agenda, with an expected emphasis on GETs policy, including DLRs.

R Street submitted initial and reply comments on the DLR NOI.[7] We hereby submit comments on the DLR ANOPR.

II. Summary of R Street Position

The ANOPR correctly recognizes that DLRs can increase the capacity, efficiency, and/or reliability of transmission facilities by accounting for real-time weather conditions. Studies estimate that DLRs increase transmission transfer capability by up to 25 percent.[8] DLRs have been, and will continue to be chronically underutilized because of TPs' perverse incentives under cost-of-service regulation. This inhibits market trade by inflating congestion costs unnecessarily. Thus, the status quo is unjust and unreasonable. The ANOPR problem statement is sound, and the need for reform is overdue.

R Street provides the following policy recommendations, some in response to ANOPR prompts and some beyond it:

- *Adopt DLR requirements on TPs, ideally using a rebuttable presumption of prudence under certain circumstances, unless otherwise demonstrated by the TP to fail a cost-benefit test*. Some DLR requirements, such as solar heating based on the sun's position, constitute universal best practice and warrant a uniform requirement to maximize net benefits. The economic prudence of other DLR applications, such as wind speed and direction, may vary by circumstance. Rather than require burdensome cost-benefit tests on individual lines, the ANOPR correctly approaches this issue by proposing thresholds from which to identify wind-based DLR candidate lines. Any threshold-based requirements the Commission adopts should err on the side of setting threshold levels to capture the overwhelming majority of cases where DLRs would expect to pass a cost-benefit test. This will likely result in more TP self-exemption pursuits, which is consistent with their incentives, whereas setting weak thresholds is unlikely to result in opt-in behavior given TP incentives. The Commission should not expand self-exemption

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[6] Jennifer Chen and Devin Hartman, "Transmission Reform Strategy from a Customer Perspective: Optimizing Net Benefits and Procedural Vehicles," *R Street Policy Study* No. 257, May 2022. https://www.rstreet.org/wp-content/uploads/2022/05/RSTREET257.pdf.

[7] "Comments of the R Street Institute on Implementation of Dynamic Line Ratings," Docket No. AD22-5-000, April 25, 2022. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20220426-5050&optimized=false.

[8] Warren Wang and Sarah Pinter, "Dynamic Line Rating Systems for Transmission Lines," Department of Energy, April 25, 2015. https://www.energy.gov/sites/prod/files/2016/10/f34/SGDP_Transmission_DLR_Topical_Report_04-25-14.pdf.

criteria. The proposed criteria are adequate for TPs to demonstrate needed compliance changes, such as those from supply chain backlogs.

- *Implement DLRs assertively, irrespective of the RTO/non-RTO asymmetry*. The choice of optimal DLR policy instrument and implementation criteria likely hinges on the quality of congestion transparency, and thus presents a sharp contrast between regional transmission organizations (RTOs) and non-RTO regions. The more aggressively the Commission plans to bolster congestion-cost transparency in non-RTO regions, the stronger the DLR policies can be calibrated. The Commission has been reluctant to create stronger requirements on TPs in RTO regions relative to non-RTO regions because doing so may create a disincentive for TP participation in RTOs. R Street discourages the Commission from using this rationale to weaken DLR requirements in RTO regions, as superior DLR utilization would enhance the net benefits of RTO participation for consumers and the state. The determinates of RTO expansion hinge on many factors that tilt in favor of DLR adoption to enrich RTO value proposition, as the perceived net benefits are strong considerations in state RTO expansion conversations, such as those underway in the West.[9]
- *Establish a routine GETs forum*. DLRs, as with GETs overall, are in the relatively early stages of commercial deployment. Their benefits and commercial readiness will improve over time, and they should continue moving down the cost curve. The economic prudence of GETs adoption is evolving rapidly, and it is quite possible that GETs applications that are premature today will be prudent in the near future. Even when GETs, like most DLRs, are deemed prudent, lessons from implementation are rapidly evolving and could expedite adoption, lower costs, and boost reliability by minimizing mistakes.[10] A routine GETs forum would improve compliance with existing GETs policy and improve the quality and expedience of future GETs policymaking.
- *Refine transmission congestion-transparency measures in non-RTO regions for DLR purposes.* Aspects of the ANOPR's proposed Limiting Element Rate (LER), with modification, may serve as congestion indicators sufficient to identify priority DLR candidate lines. R Street offers alternatives to the LER approach, including a production cost modeling-based requirement to assess congestion costs in non-RTO areas. The Commission may forego this recommendation if it instead opts for the preferable policy direction of establishing robust transmission congestion-transparency policy and institutions in non-RTO areas.
- *Pursue robust transmission congestion transparency outside of RTOs for purposes beyond DLRs.* The ANOPR reinforces that transmission congestion is unacceptably opaque in non-RTO regions lacking an energy imbalance market. The adverse economic and reliability consequences extend far beyond the scope of DLR adoption. The conditions in bilateral-only areas fundamentally undermine open-access transmission policy and the underpinnings of market-based rate authority. This cannot be reconciled

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[9] Michael Giberson, "An RTO for the West: Opportunities and Options," *R Street Policy Study* No. 308, September 2024. https://www.rstreet.org/wp-content/uploads/2024/09/FINAL2_r-street-policy-study-no-308-1.pdf.
[10] John Engel, "A utility tried out dynamic line ratings. How did it go?," Power Grid International, Aug. 22, 2024. https://www.power-grid.com/td/transmission/a-utility-tried-out-dynamic-line-ratings-how-did-it-go/#gref.

with the objectives of Order No. 890 to remedy undue discrimination and provide for transmission system transparency.[11] The Commission should strongly consider pursuing robust economic congestion-transparency reforms outside of RTOs with a bigger purpose in mind. This likely requires a related and separately dedicated proceeding. Potential remedies include requiring the adoption of an independent transmission monitor (ITM), if not energy imbalance markets, in non-RTO areas.

III. Response to ANOPR

The body of evidence, including previous R Street comments, has demonstrated the economic justification for regulatory intervention to require cost-effective GETs adoption.[12] In a competitive marketplace, no such intervention is needed, as firms have incentive to adopt cost-reducing technologies. Cost-of-service regulation, however, notoriously results in perverse incentives for cost control.

Nearly all transmission is subject to cost-of-service regulation. However, some lines adopted the competitive merchant transmission model with voluntary planning and cost allocation. Given the cost-control incentives of pure merchant transmission owners (TOs), it is reasonable to excuse them from GETs requirements. For example, merchant TOs have an incentive to expand their transmission capacity to increase revenues from voluntary subscriptions. R Street's comments hereafter refer to policy applicable to the vast majority of TOs that reside on cost-of-service regulation.

The Commission established an unofficial precedent in Order 881 of requiring economical GETs adoption as a matter of good utility practice. Economical DLR policy, however, is far more complicated than the AARs covered under Order 881. AARs constitute good utility practice in every application, and, thus, a uniform requirement like Order 881 should maximize net benefits in the aggregate and at the individual-line level. This is not the case for some DLRs, which pass a cost-benefit test only under certain circumstances.

Given the sheer number of transmission lines, requiring line-specific cost-benefit tests is unduly burdensome. Therefore, the use of weather and/or congestion thresholds to provide a preliminary screen for DLR economics is a useful tool to identify specific lines most likely to pass a DLR cost-benefit test. This should reduce the administrative cost of assessing DLR prudence.

R Street defers to parties with specific DLR engineering expertise as to the prudence of policy instrument calibration, such as wind speed thresholds. R Street instead weighs in on the rationale for determining thresholds and the choice of policy instrument.

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[11] "Preventing Undue Discrimination and preference in Transmission Service," Federal Energy Regulatory Commission, Order No. 890, Feb. 16, 2007. https://www.ferc.gov/sites/default/files/2020-06/OrderNo.890.pdf.

[12] "Comments of the R Street Institute before the Federal Energy Regulatory Commission on Post-Workshop Comments on Grid-Enhancing Technologies," Docket No. AD19-19-000. https://www.rstreet.org/wp-content/uploads/2020/02/FINAL-Hartman-GETs_Post-Workshop_Comments.pdf.

R Street advises the Commission to set thresholds at levels that will include nearly every case of prudent DLR application, in conjunction with an opt-out mechanism contingent upon a cost-benefit test that intervenors can challenge. Given the financial incentives of TPs to forego economical DLRs, it is reasonable to expect TPs to pursue opt-outs, or self-exemptions, voluntarily. TPs are unlikely to opt-in for the same reason, which is why calibrating thresholds too low is likely to result in more foregone net benefits from underutilized DLRs than a strong threshold with opt-outs would result in uneconomic DLR adoption. Thus, the policy instrument most likely to maximize net benefits for customers is using weather thresholds to establish a rebuttable presumption of prudence for DLR use, unless otherwise demonstrated by TPs using a cost-benefit test.

ANOPR Proposals

The ANOPR proposes to require line ratings that reflect solar heating based both on solar position and forecastable cloud cover. The proposal would also require that line ratings reflect forecasted wind speed and direction for certain lines in windy and congested areas. There is demonstrable evidence that each of these conditions can materially affect line ratings. This, combined with the policy instrument choice considerations noted above, generally makes the use of such weather-condition thresholds a reasonable proxy to establish whether a rebuttable presumption of DLR as good utility practice should exist.

The ANOPR proposes to apply the solar requirement for all transmission lines. The benefits of solar flux, as gauged by line rating effect, are roughly commensurate with temperature effects.[13] Temperature effects were clearly sufficient to justify Order 881. The question is whether the additional cost of the solar requirement is less than the benefits that would be seen uniformly across transmission lines. If so, the solar requirement is prudent on the basis of passing cost-benefit tests for all applications, as with AARs. If the Commission has reason to believe that this is usually, but not always, the case, then it is prudent to have a default solar requirement as the rebuttable presumption of prudence, unless otherwise demonstrated by TPs using a cost-benefit test.

The proposed solar requirement derived from the sun's position is straightforward. This may easily constitute uniform best practice. The second solar requirement provision would require TPs to reflect, for each hour, the impact of forecastable cloud cover on line ratings. If this requires substantial additional cost, it may be necessary to differentiate the conditions between the solar requirements.

[13] Kenneth R. Fenton, Jr., et al., "Dynamic Line Rating Using The High Resolution Rapid Refresh (HRRR) Model," Nov. 8, 2017, p. 29. https://renewableenergy.inl.gov/Conventional%20Renewable%20Energy/2017%20DLR%20Workshop/DLR%202017%20Presentations/11.8%20Keynote%20(NOAA)_Fenton.pdf.

R Street emphasizes that wind requirements are particularly important and have far greater congestion-relief potential than accounting for other weather conditions in line ratings. Typical wind speed variations change line ratings by multiples, with more than an order of magnitude larger rating impact than temperature or solar flux.[14] Similarly, wind direction effects on line ratings are multiples greater than those of temperature and solar flux.[15]

That said, wind-based line rating practices are less mature than temperature-based ones.[16] Technology providers use different methods to establish wind speed for ratings calculations, which influences cost, reliability, accuracy, maintenance, cyber requirements, and more.[17] Compared to other GETs, DLR has not been as rigorously evaluated and has fewer industry guides and standards for best practices.[18] This creates a policy onus to be flexible on implementation and recognize that best practices are evolving rapidly, which reinforces the R Street recommendation to establish a routine GETs forum.

The ANOPR proposes a wind requirement for select transmission lines only. Requirements for line ratings to account for wind speed and direction are clearly reasonable; they are more important than the temperature-based ratings the Commission has already found prudent. The proposed wind speed threshold seems reasonable. Granted, line ratings exhibit strong sensitivity to low wind speeds.[19] Further, a threshold test may miss some synergistic effects. As mentioned previously, the Commission should err on the side of setting the threshold at a level to capture the overwhelming majority of cases where DLRs would be expected to pass a cost-benefit test.

The Commission need not use a congestion threshold if it adopts a rebuttable presumption of wind-based DLRs with a TP self-exemption if benefits do not exceed costs. That is, congestion relief is already baked-in as a benefit criterion. The ANOPR also considers requiring a TP to use specific sensors, however this is unnecessary if the performance factor requirements are adequate, and may age poorly as technology evolves.

The ANOPR's proposed TP self-exemption from the wind requirement has appropriate technical conditionality attached to it and should be retained. That is, TPs should be allowed to self-exempt only if they can demonstrate that wind conditions do not affect a line rating or do not pass a cost-benefit test. A key is to have sufficient benefits information in non-RTO areas, where avoided congestion is difficult to measure. The Commission should not expand self-exemption criteria. If issues like supply-chain backlogs arise, the onus should be on the TP to demonstrate

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[14] Ibid.
[15] Ibid.
[16] Ann Lafoyiannis et al., "Accelerating and Scaling Up GETs," ESIG Webinar, May 16, 2024. https://www.esig.energy/event/webinar-accelerating-and-scaling-up-gets.
[17] Ibid.
[18] Ibid.
[19] Fenton, et al. https://renewableenergy.inl.gov/Conventional%20Renewable%20Energy/2017%20DLR%20Workshop/DLR%202017%20Presentations/11.8%20Keynote%20(NOAA)_Fenton.pdf.

compliance-feasibility problems and granted relief should be conditioned upon valid implementation challenges.

The Commission should determine its final self-exemption policy on the presumption that TPs will aim to minimize compliance with a final rule. Thus, safeguards must be in place to ensure self-exemption cannot be gamed by TPs. A rebuttable presumption of prudence that provides an opportunity for parties to intervene is preferable to an automatic process that provides parties no chance to challenge if TPs finagle a loophole.

The Commission also proposes new transparency reforms to enhance congestion data-reporting practices in non-RTO areas. This would be used to identify candidate transmission lines for a wind requirement and to post and retain congestion data. R Street underscores that the value of the latter is huge and far exceeds the value of the DLR context, which these comments discuss later.

In non-RTO regions, congestion costs are not reported in isolation nor are they published in public reports. To remedy this, the ANOPR proposes a new metric, the Limiting Element Rate (LER), to serve as a proxy for congestion in non-RTO regions. The LER is a creative idea based on five triggering events. Aspects of it may be useful congestion indicators, but providing a precise measure of congestion cost may be difficult. Some LER events may have sufficient correlation with congestion to be useful for indicative purposes, which may suffice to determine priority lines for DLR applications.

A variety of challenges may make LER difficult to implement, such as definitional ambiguity and TP gaming of reported curtailment and redispatch events, which is explained in the next subsection. Redispatch often indicates congestion, but it may also result from non-congestion factors like TP management of operating reserve margins, so it is not a perfect measure.[20] Further, TP denials of firm service may in some cases constitute an OATT violation. Beyond firm service, it is worth considering interruptible load events as well.[21]

The following excerpt from the 2023 Department of Energy National Transmission Needs Study is quite insightful regarding the merits of the LER concept based on transmission service denials:

> Denials of requests for transmission service provide a direct, but incomplete, measure of congestion. Denials are a direct measure because they reflect a desire to use the transmission system that was foregone because of one or more transmission constraints. But denials do not provide information on the economic significance of the congestion they represent and no information on the value of transmission or other efforts to relieve the constraints that underlie this congestion. Information on denials of requests for transmission service is also an incomplete measure because it does not capture requests that were not made because of users' perceptions

[20] "Competition in Bilateral Wholesale Electric Markets: How Does it Work?," Energy Policy Group, LLC, February 2016. https://hepg.hks.harvard.edu/files/hepg/files/bilateral_markets_white_paper_final.pdf.

[21] Le Anh Tuan et al., "Transmission congestion management in bilateral markets: An interruptible load auction solution," *Electric Power Systems Research* 74:3 (June 2005), pp. 379-389. https://www.sciencedirect.com/science/article/abs/pii/S0378779605000660?via%3Dihub.

> of the availability of services. That is, the availability of transmission services is routinely updated. Potential users seeking those services might forego requesting them at times of limited availability, in part because of experience of requests being denied under these conditions. An additional reason a desired service might not be requested is because the ATC had already been set to zero.[22]

The ANOPR considers including a sixth triggering event: low available transfer capacity (ATC) events. R Street supports the expansion of a low ATC-based concept for measuring congestion outside of RTOs. It is also worth exploring alternative approaches to measuring congestion costs in non-RTO areas.

Alternatives and/or Additions to the ANOPR Proposals

The ANOPR seeks comment on new methods to measure congestion and related data-reporting requirements. Since the migration from zonal to nodal markets, economic congestion measures have not been a concern in RTO markets. There may be some improvements in reporting consistency, as RTOs vary in how they publish congestion costs. For example, not all RTOs publish day-ahead and real-time congestion; some only report total congestion. Overall, the need to improve congestion measures and reporting is almost exclusively a non-RTO problem, specifically in areas that are bilateral only and that lack an energy imbalance market.

R Street emphasizes that, despite the noble goal of improving economic congestion transparency outside of RTOs, it is unlikely that a silver bullet exists. The Commission may prefer to pursue modifications of its proposal, alternatives to its proposal, or a combination. Alternative approaches to measure economic congestion will be inferior to the direct measure of the congestion component of locational marginal pricing (LMP). Nevertheless, attempts to reverse-engineer the congestion component of LMP might be a marked improvement over the status quo. Some options to do this might include combining proxies of generator marginal cost with existing indicators of binding constraints, such as transmission loading relief (TLR) and low-ATC event alternatives. In theory, marginal price differential analysis would also indicate congestion but would require drastically enhanced data provisions outside of RTOs.

A workable alternative may be to use a production cost modeling-based approach. Approximating the marginal change in total production cost to relieve a constraint would yield the shadow price of the constraint. Paired with information on the flow on a constraint at an injection point would provide a measure of shift factor. These two components would enable a calculation of congestion value.

To measure marginal production cost, a perhaps simplistic approach would be to compare actual production costs to a simulation of production costs with no transmission constraints. The simulation would provide the counterfactual of an unconstrained transmission system,

[22] "National Transmission Needs Study," U.S. Department of Energy, October 2023, pp. 16-17. https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

which would result in no wholesale market price separation by location. The delta between actual and unconstrained production costs would be a strong, but not exact, approximation of congestion. The delta would also indicate line loss. Although adjusting for line loss would be necessary to not overvalue congestion, challenges in doing so precisely would not demerit the exercise. The vast majority of cost differentials should be attributable to congestion. For comparison, recent market price differential analyses of non-RTO regions note that small price differences of $0-$5/megawatt-hour may result from line losses, not congestion.[23]

A key question is whether this aggregate congestion indicator could be implemented with sufficient spatial granularity to approximate the flow on the constraint at a specific location or shift factor. Typically, a system has multiple binding constraints at any given time. These individual congestion values can be positive or negative. The important thing is to reveal the net system-wide value of generation at a given location. It should be possible to measure congestion based on the average marginal cost of congestion for a given binding line over the evaluation period. The frequency of evaluation should balance TP burdens with the economic value of timeliness of public congestion-cost posting. Monthly or perhaps weekly evaluations could be reasonable, given the time it takes to populate and execute contemporary production-cost models.

Temporal granularity would also be important. Five-minute intervals may be ideal, as RTOs use, given that the bulk of congestion value is usually captured in hourly increments. Standard industry production-cost software, such as PROMOD, has long been capable of hourly modeling. However, advanced production-cost models simulate at five-minute intervals now, and as wind and solar growth increase production variation, production-cost modeling time steps are decreasing from hourly to five-minute solution frequencies.[24]

A workably accurate simulation would be key, as simulations—production cost or otherwise—are only as accurate as their inputs. The simulation could simply use actual loads. It would need to hold generation and transmission outages constant.

A key input consideration is that some generators in a TP system may not be owned by the TP. Those third-party owners may be unwilling to disclose full marginal cost information to the TP, given commercial sensitivities. If they did, the TP's generator data access must be separated from its merchant generation fleet ownership to prevent anticompetitive conduct. If third parties did not agree to provide generation cost information, TPs may need guidance on using estimates for variable costs like the prevailing area's fuel prices and heat rates based on plant vintage, as well as approximations for unit commitment costs like start-up and no-load costs. Finally, the Commission should account for expected future TP production-cost modeling practices, especially in light of Order 1920 compliance.

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[23] U.S. Department of Energy, p. 33. https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.

[24] James D. McCalley, "Production Costing Models," Security Constrained Economic Dispatch Calculation, March 5, 2024, p. 3. https://home.engineering.iastate.edu/jdm/ee552/ProductionCostModels.pdf.

Under any path forward, it is critical that the Commission move toward a consistent definition of concepts and metrics. This includes defining terms and setting measurement standards for operations like generator curtailment, redispatch, and transmission operating constraints. Utilities use different processes and vernacular to adjust their dispatch based on operating constraints, which will result in inconsistent reporting. Because the emphasis here is on identifying congestion, any terms associated with out-of-merit-order plant operation need to be understood and interpreted the same way by all parties. Terms like adjusted dispatch, net dispatch, and redispatch may be interpreted differently by various parties, which would undermine efforts to prevent undue discrimination and preference in transmission services.[25]

Standard definitions of concepts and metrics are also needed for accurate economic measures. For example, non-RTO utilities measure system lambda in different manners. For economic congestion measures, it is especially important to assess marginal cost components like start-up and no-load costs accurately and consistently.

Some stakeholders may raise concerns that standardization of transmission practices is reminiscent of standard market design. This concern can be dismissed quickly. The scope of this effort is to establish standardized vernacular and reporting requirements, not market-design features.

Overall, it is unclear what quality of economic congestion transparency might be achievable by utility-reporting improvements alone. The challenge of measuring and managing loop flows in bilateral-only areas serves as a case-in-point. Expecting self-interested utilities to safeguard competitors' generation information may prove too challenging. Expecting TPs to conduct and report economic redispatch accurately—a prerequisite to determine congestion valuation—has always been at odds with the principle of open-access transmission policy. Ultimately, the Commission may be better suited to require an independent institution to evaluate and publish economic congestion. The rationale for doing so would extend far beyond the merits of DLR implementation.

IV. Additional Action on Transmission Congestion Transparency Outside of RTOs

Problem Statement

This docket reinforces that transmission congestion is unacceptably opaque outside of RTOs. However, the adverse economic and reliability consequences extend far beyond the scope of this proceeding, which focuses on DLR adoption. Therefore, the Commission should strongly consider pursuing congestion-transparency reforms outside RTOs with a bigger purpose in mind.

[25] John Chandley and William Hogan, "A Path to Preventing Undue Discrimination and Preference in Transmission Services," Harvard University, Aug. 2, 2006. https://hepg.hks.harvard.edu/files/hepg/files/chandley_hogan_oatt_nopr_080206.pdf.

The bilateral-only problems identified in this docket and many others underscore fundamental concerns of open-access transmission policy and the underpinnings of market-based rate authority. Current practices outside of RTOs cannot be reconciled with the objectives of Order No. 890 to remedy undue discrimination and provide for transmission system transparency.[26] Considering this scope, the Commission should pursue robust economic transmission congestion-transparency reforms outside of RTOs in a related and separately dedicated proceeding.

The literature and practitioner evidence solidifies this problem statement. The literature provides several pertinent findings:

- Generally, non-RTOs lack transmission transparency, typically having less publicly reported data on available outcomes, operation, and efficiency.[27] Inefficiencies are evident in rate pancaking, trade friction, limited real-time options, and more expensive resources, all of which lead to an underutilization of existing transmission capacity and uneconomic trading outcomes.[28]
- Broad economic congestion indicators, let alone specific measures, are generally unavailable in non-RTO regions. National congestion reports do not even attempt to quantify aggregate regional congestion costs outside of RTOs, much less anything granular (e.g., nodal or line-specific). For example, in a 2023 national congestion study, Grid Strategies only estimated region-specific congestion costs for RTO regions, noting that "[n]on-RTO regions do not have transparent congestion data."[29] The 2023 Department of Energy (DOE) National Transmission Needs Study noted that RTO regions identify congestion costs incurred in each market, adding "[l]ess granular data on how transmission congestion and constraints raise overall system costs for consumers is available in non-RTO/ISO regions."[30] The report noted that "information on the economic value of congestion outside RTOs/ISOs is minimal when compared with the market price differential data available from RTOs/ISOs."[31] The DOE report proceeded to measure load-weighted congestion costs in RTO footprints only.[32]
- Congestion opacity undermines the identification of transmission needs, economic planning, and system reliability. Congestion is a key economic criterion for transmission planning. Excluding economic congestion results in costlier transmission and generation investment. In non-RTO regions, such as the West, congestion results in reliability

[26] "Preventing Undue Discrimination and preference in Transmission Service," Federal Energy Regulatory Commission, Order No. 890, Feb. 16, 2007. https://www.ferc.gov/sites/default/files/2020-06/OrderNo.890.pdf.
[27] Christina Simeone and Amy Rose, "Barriers and Opportunities to Realize the System Value of Interregional Transmission," National Renewable Energy Laboratory, June 2024, pp. 5-7. https://www.nrel.gov/docs/fy24osti/89363.pdf.
[28] Ibid., pp. 5-7. https://www.nrel.gov/docs/fy24osti/89363.pdf.
[29] Richard Doying et al., "Transmission Congestion Costs Rise Again in U.S. RTOs," Grid Strategies, July 2023, p. 3. https://gridstrategiesllc.com/wp-content/uploads/2023/07/GS_Transmission-Congestion-Costs-in-the-U.S.-RTOs1.pdf.
[30] U.S. Department of Energy. https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.
[31] Ibid.
[32] Ibid.

concerns for the entire regional system.[33] Transmission congestion and needs are expected to increase in non-RTO regions, given changes in the generation mix, load growth, and climatic conditions.[34] The DOE noted having difficulty determining transmission need because of lack of data access, particularly in the non-RTO Southeast and Florida.[35]

- Congestion is not managed economically if it is not measured economically, which it is not in bilateral-only areas. RTOs use market-based approaches to allocate ATC based on users' expressed willingness to pay for transmission services, whereas non-RTO TPs use administrative approaches to allocate transmission capacity.[36] Specifically, non-RTO regions primarily use TLRs to manage congestion, whereas RTOs principally use price to manage congestion and rarely invoke TLR.[37] Relying principally on TLRs to manage and measure congestion is not economical for several reasons. TLRs are an administrative reliability tool, not an economic measure of congestion.[38] They also do not provide an indication of expected future congestion.[39] This undermines the ability of load to hedge or competitive suppliers to account for congestion or curtailment risk in siting decisions.
- Interregional seams management is costlier in non-RTO regions than it is in RTO regions, in part because the former provides no economic measure of congestion. This has become readily apparent in seams-management discussions with western stakeholders as they migrate toward energy imbalance markets, if not full RTO progression.[40] Although major economic efficiency gains are achievable by optimizing RTO-to-RTO seams, the biggest seams-management inefficiencies are in non-RTOs regions where economic signals are suppressed by insufficient congestion measures.[41]

The beneficiaries of transmission congestion transparency include competitive suppliers and transmission consumers. Notable comments include:

- Findings from a convening of national transmission consumer groups informed a report published by R Street. The report found that a lack of independent and transparent transmission practices in non-RTO areas let entrenched monopoly utilities maintain their

[33] Ibid., p. 51.
[34] Ibid.
[35] Ibid., p. 38.
[36] U.S. Department of Energy, p. 16. https://www.energy.gov/sites/default/files/2023-12/National%20Transmission%20Needs%20Study%20-%20Final_2023.12.1.pdf.
[37] Ibid., p. 19.
[38] Ibid., p. 19.
[39] Ibid., p.19.
[40] Giberson, pp. 18-19. https://www.rstreet.org/wp-content/uploads/2024/09/FINAL2_r-street-policy-study-no-308-1.pdf.
[41] See, e.g., Travis Kavulla, "Efficient Solutions for Issues in Electricity Seams," *R Street Policy Study* No. 172, April 2019. https://www.rstreet.org/wp-content/uploads/2019/04/Final-No.-172.pdf; "The Need for Intertie Optimization," The Brattle Group, October 2023. https://www.brattle.com/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization-Reducing-Customer-Costs-Improving-Grid-Resilience-and-Encouraging-Interregional-Transmission-Report.pdf.

position against suppliers who could outperform them at lower cost.[42] For example, transmission planning in non-RTO regions combined utility plans without evaluating basic adjusted production costs of alternative transmission proposals.[43] Most customer groups saw a need for an independent monitor to perform a variety of possible functions, such as reviewing transmission planning criteria and evaluating GETs on chronically congested corridors.[44]

- An alliance of joint transmission customers, including small and large load representatives, lamented a severe lack of economic discipline and transparency in transmission practices, especially in non-RTO areas and projects exempt from RTO planning.[45] They called on FERC to equalize the treatment of Order Nos. 890 and 1000 across RTO and non-RTO regions.[46]
- Transmission-dependent utilities (TDUs) have routinely expressed the need to reform non-RTO transmission processes.[47] They have noted an extensive lack of utility congestion and production-cost measures in non-RTO areas. These deficiencies result in the inability to proactively identify more cost-effective transmission projects by undervaluing their benefits.[48] Incumbent TOs can then "limit the ability of others to propose superior alternative regional projects by simply failing to disclose their planned local projects until the eleventh hour."[49]

In short, a granular economic measure of congestion must be readily available to ensure economical transmission system operations and transmission planning. In its absence, generation and transmission rates are unnecessarily high and create material barriers to open access for transmission customers. Because no economic congestion measures are available outside of RTOs, especially at the nodal level, current practices are unjust, unreasonable, and unduly discriminatory under the Federal Power Act. Transmission consumers are increasingly calling for reform.

Prioritizing Reform

Clearly, there is a convincing problem statement that transmission congestion opacity in bilateral-only markets is unjust and unreasonable under the Federal Power Act. R Street's

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[42] Chen and Hartman. https://www.rstreet.org/research/transmission-reform-strategy-from-a-customer-perspective-optimizing-net-benefits-and-procedural-vehicles.
[43] Ibid.
[44] Ibid.
[45] "Post-Technical Conference Comments of Joint Customers before the Federal Energy Regulatory Commission on Transmission Planning and Cost Management," Docket No. AD22-8-000. https://www.rstreet.org/wp-content/uploads/2023/06/ECA-20230323-5062-1.pdf.
[46] Ibid.
[47] See, e.g., "Comments of the Transmission Access Policy Study Group on the Advanced Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," Docket No. RM21-17-000, Oct. 12, 2021, pp. 15-19. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5388&optimized=false.
[48] Ibid., pp. 15-17.
[49] Ibid., p. 16.

comments do not propose a detailed remedy but merely provide sufficient record of the problem statement and general institutional reform pathways to motivate subsequent Commission and stakeholder action.

Sufficient transmission congestion transparency appears unattainable through utility reporting requirements alone. Physical problems, like measuring and managing loop flows, and economic ones, like monetizing congestion value, are too daunting to expect self-interested, vertically integrated utilities to provide transparent, open access to the transmission system. An independent institution is needed to—at a minimum—provide granular economic congestion transparency and market monitoring.

Institutional deficiencies including, but not limited to, transmission congestion outside of RTOs explains the core motivation of transmission consumers' formation of the ITM Coalition, led by the Electricity Consumers Resource Council. Although stakeholders vary on the specific desired functions of a potential ITM, the coalition emphasizes the need for an independent monitor to assess and provide information on non-RTO transmission practices where there is little transparency. To correct the RTO/non-RTO transmission transparency asymmetry, the ITM Coalition argues that "[s]takeholders, especially consumers, in non-RTOs/ISOs should be provided the same insight into data sources, assumptions, criteria, consideration of alternatives, and information regarding potential costs as is available in RTO/ISO regions. Consumers should not be disadvantaged just because they are situated in a non-RTO."[50]

TDUs have called an ITM "essential for non-RTO regions."[51] The aforementioned joint transmission customer alliance underscored huge information gaps undermining state and federal prudence reviews, warranting "thorough pursuit of an ITM."[52] They laid out multiple procedural options to improve transmission transparency, establish an ITM, reexamine Order No. 890 compliance or reformulate criteria, and carry out other pursuits with the priority placed on non-RTO regions.[53]

Benefiting States

The potential establishment of a new regional institution may raise questions from retail stakeholders, including state regulators. First, lower transmission system costs and improved reliability benefit retail customers under states' purview. Second, it is important to clarify that

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[50] "Post-Technical Conference Comments of the ITM Coalition," Transmission Planning and Cost Management, Docket No. AD22-8-000, March 23, 2023, p. 10. https://elcon.org/wp-content/uploads/3.23.23-AD22-8-ITM-Coalition-Post-Tech-Conf-Comments.pdf.
[51] "Comments of the Transmission Access Policy Study Group on the Advanced Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," Docket No. RM21-17-000, Oct. 12, 2021, p. 18. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5388&optimized=false.
[52] "Post-Technical Conference Comments of Joint Customers before the Federal Energy Regulatory Commission on Transmission Planning and Cost Management," Docket No. AD22-8-000, p. 5. https://www.rstreet.org/wp-content/uploads/2023/06/ECA-20230323-5062-1.pdf.
[53] Ibid.

no state autonomy would be lost under an ITM-style institution. Rather, states would be empowered to better exercise their authority by making more informed decisions armed with congestion-cost information.

Congestion-cost data enhances the quality of cost-benefit analyses and least-cost service analyses. For example, this can enable the pervasive use of production-cost assessments to determine least-cost transmission solutions. This results in more economical transmission regulation overseen by states, especially in non-RTO footprints.

Done properly, congestion transparency outside of RTOs would presumably shed light on suboptimal or plainly uneconomic operations of utility power plants. The Commission should be clear that correcting uneconomic utility generation practices is, by and large, a retail issue for state regulators. However, better transparency of transmission congestion, which is squarely under Commission jurisdiction, leads to better information availability for PUCs to gauge the prudence of what is in their jurisdiction, such as utility-generation investments and operating procedures.

Travis Kavulla, the former president of the National Association of State Utility Regulators, noted legitimate problems with cost-of-service utilities operating power plants uneconomically because utilities lack incentive to "operate efficiently in power markets or in their fuel supply negotiations."[54] He noted the need for retail reforms by PUCs, such as automatic rate adjustment mechanisms or "trackers."[55] In RTOs with cost-of-service states, like most of the Midcontinent Independent System Operator (MISO), uneconomic operation is far easier to detect and can inform PUC mechanisms like trackers, used-and-useful, and certificate-of-need decisions. For example, MISO's independent market monitor detected some uneconomic utility plant operations and considered it evidence of the poor incentives of cost-of-service regulation.[56] Independent monitors can report such generator-specific information to PUCs within RTOs, but no such institutional arrangement exists outside of RTOs.

To be clear, various forms of transmission transparency could be improved in RTOs, but the fundamental problems exist in the opaque, non-RTO regions. The key concern within RTO footprints are projects exempt from regional economic transmission planning, namely reliability-need and local projects. State regulators have noted that an ITM could furnish information on such projects, in addition to a broader objective of ensuring Order 890 compliance.[57] For example, the director of the North Carolina Utilities Commission's Energy

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[54] Travis Kavulla, "Reviewed Work: 'The Billion-Dollar Coal Bailout Nobody is Talking About: Self-Committing in Power Markets'," R Street Responds, June 12, 2019. https://www.rstreet.org/commentary/reviewed-work-the-billion-dollar-coal-bailout-nobody-is-talking-about-self-committing-in-power-markets.
[55] Ibid.
[56] "A Review of the Commitment and Dispatch of Coal Generators in MISO," Potomac Economics, September 2020. https://www.potomaceconomics.com/wp-content/uploads/2020/09/Coal-Dispatch-Study_9-30-20.pdf.
[57] Devin Hartman and Kent Chandler, "Stakeholder Soapbox: A Transmission Planning Resolution Emerges," *RTOInsider*, Dec. 12, 2022. https://www.rtoinsider.com/31281-stakeholder-soapbox-tx-planning-resolution-emerges.

Division, whose state resides outside of an RTO, said "we desperately need something like an independent transmission monitor to assist us."[58]

Altogether, an ITM-type of institutional arrangement is the bare minimum needed to ensure that rates are just and reasonable in non-RTO regions. It is also possible for independent balancing authorities to publish congestion measures contingent upon stricter TO reporting requirements. An economically superior, non-RTO alternative is to establish an energy imbalance market.[59]

V. Conclusion

RSI respectfully requests that the Commission consider the comments contained herein.

Respectfully submitted,

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[58] Rich Heidorn, Jr., "FERC Tech Conference Highlights Regulatory Gaps on Transmission Oversight," *RTOInsider,* Oct. 10, 2022. https://www.rtoinsider.com/30933-ferc-tech-conference-highlights-regulatory-gaps-tx-oversight.
[59] Jennifer Chen and Michael Bardee, "How Voluntary Electricity Trading Can Help Efficiency in the Southeast," *R Street Policy Study* No. 201, August 2020. https://www.rstreet.org/research/how-voluntary-electricity-trading-can-help-efficiency-in-the-southeast.

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