DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM24–6–000]

Implementation of Dynamic Line Ratings

AGENCY: Federal Energy Regulatory Commission.

ACTION: Advance notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is issuing an advance notice of proposed rulemaking presenting potential reforms to implement dynamic line ratings and, thereby, improve the accuracy of transmission line ratings. These potential reforms would require transmission line ratings to reflect solar heating based on the sun's position and forecastable cloud cover and require transmission line ratings to reflect forecasts of wind conditions on certain transmission lines. The potential reforms would also ensure transparency in the development and implementation of dynamic line ratings and enhance data reporting practices related to congestion in non-regional transmission organization/independent system operator regions to identify candidate transmission lines for the requirement to reflect forecasts of wind conditions. The Commission invites all interested persons to submit comments on the potential reforms and in response to specific questions.

DATES: Comments are due October 15, 2024 and Reply Comments are due November 12, 2024.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways. Electronic filing through *https://www.ferc.gov,* is preferred.

- *Electronic Filing:* Documents must be filed in acceptable native applications and print-to-PDF, but not in scanned or picture format.
- For those unable to file electronically, comments may be filed by USPS mail or by hand (including courier) delivery.
  - ○ *Mail via U.S. Postal Service Only:* Addressed to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.
  - ○ *Hand (including courier) Delivery:* Deliver to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

The Comment Procedures section of this document contains more detailed filing procedures.

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I. Introduction

1. In this advance notice of proposed rulemaking (ANOPR), the Federal Energy Regulatory Commission (Commission), pursuant to its authority under section 206 of the Federal Power Act (FPA),[1] is considering the need to establish requirements for transmission providers to use dynamic line ratings to improve the accuracy of transmission line ratings. Dynamic line ratings, or DLRs, are transmission line ratings that reflect up-to-date forecasts of weather conditions, such as ambient air temperature, wind, cloud cover, solar heating, and precipitation, in addition to transmission line conditions such as tension or sag.[2] The Commission is also considering reforms to ensure transparency in the development and implementation of dynamic line ratings.

2. In 2021, the Commission issued Order No. 881, to revise its *pro forma* Open Access Transmission Tariff (OATT) and the Commission's regulations to improve the accuracy and transparency of transmission line ratings.[3] Specifically, the Commission found that the use of only seasonal and static temperature assumptions in developing transmission line ratings would result in transmission line ratings that do not accurately represent the transfer capability of the transmission system.[4] The Commission found that inaccurate transmission line ratings result in unjust and unreasonable Commission-jurisdictional rates.[5]

3. Building upon past Commission actions designed to improve the accuracy and transparency of transmission line ratings, this ANOPR raises questions and explores potential reforms to further enhance transmission line ratings and congestion reporting practices. We preliminarily propose and seek comment on a DLR framework for reforms to improve the accuracy of transmission line ratings and ensure transparency in the development and implementation of transmission line ratings. These potential DLR reforms would require transmission line ratings to reflect the impacts of solar heating by considering the sun's position and forecastable cloud cover. They would also require transmission line ratings to reflect forecasts of wind conditions—wind speed and wind direction—on certain transmission lines. The potential reforms also would enhance data reporting practices related to congestion in non-regional transmission organization (RTO)/independent system operator (ISO) regions to identify candidate transmission lines for any wind requirement. We seek comment on this framework and whether any reforms to alter the requirements for transmission line ratings are needed to ensure rates for Commission-jurisdictional service are just and

[1] 16 U.S.C. 824e.

[2] *See, e.g.,* 18 CFR 35.28(b)(14).

[3] *Managing Transmission Line Ratings,* Order No. 881, 87 FR 2244 (Jan. 13, 2022), 177 FERC ¶ 61,179 (2021), *order addressing arguments raised on reh'g,* Order No. 881–A, 87 FR 31712 (May 25, 2022), 179 FERC ¶ 61,125 (2022).

[4] *Id.* P 3.

[5] *Id.* PP 3, 29.

reasonable, and not unduly discriminatory or preferential.

II. Background

4. This ANOPR proposes a DLR framework for reforms that would build upon past Commission actions designed to improve the accuracy of transmission line ratings and ensure transparency in the development and implementation of transmission line ratings. This section describes those past actions, related Commission proceedings, how transmission line ratings are determined, including the incorporation of weather variables into thermal ratings and the use of sensors, and how transmission services are provided and procured in the bulk electric system to provide context for the reforms proposed herein.

A. Transmission Line Rating Proceedings

1. Order No. 881

5. In December 2021, the Commission issued Order No. 881, which reformed both the *pro forma* OATT and the Commission's regulations to improve the accuracy and transparency of transmission line ratings.[6] The Commission explained that seasonal or static transmission line ratings, which represent the maximum transfer capability of each transmission line and are typically based on conservative assumptions about long-term air temperature and other weather conditions, may not accurately reflect the near-term transfer capability of the transmission system and that more accurate transmission line ratings can be achieved through the use of ambient-adjusted ratings (AAR) and DLRs.[7] Therefore, the Commission adopted requirements for the use of AARs,[8] and the use of uniquely determined emergency ratings that include separate AAR calculations, for use in the operations horizon and in post-contingency simulations of constraints.[9] The Commission further required associated transparency requirements and certain discrete requirements related to removing barriers to DLRs, including requiring RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission providers to electronically update transmission line ratings at least hourly. The Commission also required the consideration of solar heating as part of AARs in the form of separate daytime and nighttime ratings. For this daytime/nighttime ratings requirement, transmission providers must assume solar heating during daylight hours, and nighttime ratings must reflect the absence of solar heating.[10] Although the Commission declined to require hourly forecasts of solar heating, it clarified that nothing in the final rule prohibited a transmission provider from voluntarily implementing hourly forecasts for solar heating.[11]

6. With respect to DLRs, the Commission in Order No. 881 adopted as the definition of DLR: a transmission line rating that applies to a time period of not greater than one hour and reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar heating intensity, transmission line tension, or transmission line sag.[12] Although organizationally Order No. 881 discussed the DLR requirement for RTOs/ISOs separately from the AAR requirement,[13] the Commission defined DLRs to include ambient air temperature and solar heating.[14] Consistent with that definition, in this ANOPR, references to DLR include AAR (which, as used in Order No. 881, includes ambient air temperatures and solar daytime/nighttime ratings) as well as the solar requirement and wind requirement proposed below.[15]

7. The Commission agreed with commenters that highlighted the benefits of DLR implementation. The Commission stated that, absent RTOs/ISOs having the capability to incorporate DLRs, voluntary implementation of DLRs by transmission owners in some RTOs/ISOs would be of limited value, as their more dynamic ratings and resulting benefits would not be incorporated into RTO/ISO markets.[16] For example, the Commission acknowledged that the use of DLRs generally allows for greater power flows than would otherwise be allowed, and that their use can detect situations when power flows should be reduced to maintain safe and reliable operation and avoid unnecessary wear on transmission equipment.[17] However, the Commission also recognized that implementing DLRs is more costly and challenging than implementing AARs, and found that the record in the proceeding was insufficient to evaluate the benefits, costs, and challenges of DLR implementation at that time.[18] As a result, the Commission declined to adopt any reforms that would mandate DLR implementation based on the record in that proceeding and instead incorporated that record into a new proceeding in Docket No. AD22–5–000 to further explore DLR implementation.[19]

8. The Commission required implementation of the requirements adopted in Order No. 881 by July 12, 2025, three years after compliance filings were due.[20]

2. Notice of Inquiry

9. On February 17, 2022, the Commission issued a Notice of Inquiry[21] in which the Commission asked a series of questions about whether and how the use of DLRs might be needed to ensure just and reasonable Commission-jurisdictional rates; potential criteria for DLR requirements; the benefits, costs, and challenges of implementing DLRs; the nature of potential DLR requirements; and potential timeframes for implementing DLR requirements. The Commission received initial comments from 40 entities, reply comments from six

[6] 177 FERC ¶ 61,179.

[7] Unlike static thermal line ratings, which are calculated annually or seasonally based on constant values of line current and worst-case weather conditions, AARs are determined using near-term forecasted ambient air temperatures and updated daytime/nighttime solar heating values. As noted above, DLRs are calculated using up-to-date forecasts of ambient air temperature, plus other weather conditions such as wind, cloud cover, solar heating, and precipitation, in addition to transmission line conditions such as tension or sag.

[8] AAR is defined as a transmission line rating that: (a) applies to a time period of not greater than one hour; (b) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; (c) reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently; and (d) is calculated at least each hour, if not more frequently. *Pro forma* OATT, attach. M, Definitions; *see also* 18 CFR 35.28(b)(12).

[9] "Emergency Rating" is defined as a transmission line rating that reflects operation for a specified, finite period, rather than reflecting continuous operation. An emergency rating may assume an acceptable loss of equipment life or other physical or safety limitations for the equipment involved. 18 CFR 35.28(b)(13); *pro forma* OATT, attach. M, Definitions.

[10] Order No. 881, 177 FERC ¶ 61,179 at P 149.

[11] *Id.* P 150.

[12] 18 CFR 35.28(b)(14); *see* Order No. 881, 177 FERC ¶ 61,179 at PP 7, 235, 238.

[13] *Compare* Order No. 881, 177 FERC ¶ 61,179 at PP 47–192 (section IV.B "Ambient-Adjusted Ratings") *with id.* PP 235–266 (section IV.E "Dynamic Line Ratings").

[14] *See supra* n.12.

[15] This ANOPR does not propose any changes to the requirements of Order No. 881.

[16] Order No. 881, 177 FERC ¶ 61,179 at P 255.

[17] *Id.* P 253.

[18] *Id.* P 254.

[19] *Id.* PP 7–9.

[20] We note, however, that certain transmission providers requested and were granted extensions by the Commission. *E.g., N.Y. Indep. Sys. Operator, Inc.,* 186 FERC ¶ 61,237 (2024) (granting an extension until no later than December 31, 2028); *S. Co. Servs. Inc.,* 187 FERC ¶ 61,055 (2024) (granting an extension up to and including December 31, 2026).

[21] *Implementation of Dynamic Line Ratings,* Notice of Inquiry, 178 FERC ¶ 61,110 (2022) (NOI).

entities, and supplemental comments from four entities.[22]

3. Comments Supporting DLRs

10. Comments in response to the NOI suggest potential net benefits of implementing DLRs in certain circumstances. Various commenters state that DLRs would reduce congestion costs.[23] Other commenters highlight DLR benefits related to reduced renewable energy curtailment and reduced interconnection costs.[24]

11. Commenters assert that DLR implementation can help mitigate congestion associated with planned and/or unplanned long-term outages of generation or transmission.[25] Clean Energy Parties identify two examples in which sensors for transmission line sag and transmission line temperature can serve a reliability function, indicating that the cost-benefit analysis for installation of sensors to enable DLR is not limited to economic benefits. Clean Energy Parties assert that DLR sensors serve reliability by detecting potential fire danger during high wind periods and detecting real-time transmission line capacity.[26]

12. Commenters also note that weather sensors (which measure, *e.g.,* wind speed, wind direction and/or cloud cover) and conductor sensors (which measure conductor properties such as temperature, sag or tension) can provide real-time operational awareness. Commenters explain that such operational awareness can be useful for a transmission provider to monitor specific events, such as ice on a transmission line or the response of a transmission line operating near its rating limit. Commenters also state that local sensors provide an additional way to verify weather conditions in real time, which may be especially useful along frequently limiting spans.[27]

13. Some commenters discuss different considerations and challenges with DLRs, which are described in more detail below.

B. Transmission Line Ratings Background

14. Transmission line ratings are determined by the most limiting element among the components that make up the transmission facility, which includes the conductors and the associated equipment necessary for the transfer or movement of electric energy across a transmission facility (*e.g.,* switches, breakers, busses, line traps, metering equipment, and relay equipment).[28] A transmission line rating is the maximum transfer capability of a transmission line taking into account the technical limitations on conductors, relevant transmission equipment, and the transmission system.[29] As the Commission explained, ''Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.'' [30] For purposes of the discussion that follows, references to transmission ''line'' ratings encompass ratings for all transmission equipment that has a rating.

1. Different Types of Transmission Line Ratings: Based on Thermal, Voltage, and Stability Limits

15. Transmission line ratings are based on the most limiting of three types of limits: thermal limits; voltage limits; and stability limits. The thermal limit reflects the maximum amount of power that can safely flow on a transmission line without it overheating. Each transmission line may have several thermal limits depending on the duration of power flow considered, with a lower thermal limit for normal operations and higher thermal limits for long-term and short-term emergency operations. However, voltage and stability limits are typically fixed values that limit the power flow on a transmission line from exceeding the point above which there is an unacceptable risk of a voltage or stability problem.

2. Calculating Thermal Ratings

16. Thermal ratings are determined based on the physical characteristics of the conductor and assumptions about environmental conditions (*e.g.,* ambient air temperature, sun position, cloud cover, wind, or other weather conditions). Thermal ratings determine the maximum amount of power that can flow through a conductor while keeping the conductor under its ''maximum operating temperature,'' a limit designed to prevent wear on the conductor and comply with ground clearance and conductor sag requirements. Engineering standards, including those published by the Institute of Electrical and Electronics Engineers (IEEE) and the International Council on Large Electric Systems (CIGRE), establish methods for calculating transmission line ratings based on the conductor properties and weather conditions.[31] The National Electrical Safety Code (NESC) provides minimum clearance requirements between the transmission conductor and other facilities, including, but not limited to, minimum clearances to other electrical circuits, communications cables, structures below the transmission conductor, vegetation, railroads, roadways, waterways, and ground.[32]

17. Thermal ratings are calculated using formulas, which are based on forecast- or assumption-based inputs that require the use of confidence levels. Confidence levels represent the likelihood that the actual real-time value of that input is less than or equal to the assumption or forecast. For some inputs in thermal ratings formulas, forecast uncertainty may not be normally distributed. In other words, there may be more forecast uncertainty as the input approaches a historic limit or extreme level. For example, if an ambient air temperature forecast approaches an extreme level (*e.g.,* an unusually high temperature for a given location), the uncertainty about that forecast may become skewed such that the actual ambient air temperature value is more likely to be below the forecast temperature than above it.[33] Choosing

[22] A list of commenters in the NOI proceeding and their abbreviated names is located in the appendix.

[23] WATT/CEE Comments, Docket No. AD22–5, at 4 (filed Apr. 25, 2022); DOE Comments, Docket No. AD22–5, app A (Grid-Enhancing Technologies: A Case Study on Ratepayer Impact (Feb. 2022)) at 40–41, 52–53 (filed Apr. 25, 2022); R Street Institute Comments, Docket No. AD22–5, at 8 (filed Apr. 26, 2022); ELCON Comments, Docket No. AD22–5, at 5–6 (filed Apr. 25, 2022); Certain TDUs Comments, Docket No. AD22–5, at 7, 9 (filed Apr. 25, 2022).

[24] WATT/CEE Comments, Docket No. AD22–5, at 4 (filed Apr. 25, 2022) (citing Consentec, *The Benefits of Innovative Grid Technologies* (Dec. 8, 2021) and T. Bruce Tsuchida, Stephanie Ross, and Adam Bigelow, *Unlocking the Queue with Grid-Enhancing Technologies* (Feb. 1, 2021)); DOE Comments, Docket No. AD22–5, attach. A at 44 (filed Apr. 25, 2022); ELCON Comments, Docket No. AD22–5, at 7 (filed Apr. 25, 2022).

[25] PJM Comments, Docket No. AD22–5, at 5 (filed May 9, 2022); Clean Energy Parties Comments, Docket No. AD22–5, at 21 (filed Apr. 25, 2022); LineVision Comments, Docket No. AD22–5, at 5 (filed Apr. 22, 2022).

[26] Clean Energy Parties Comments, Docket No. AD22–5, at 15 (filed Apr. 25, 2022).

[27] *See* LineVision Comments, Docket No. AD22–5, at 8–10 (filed Apr. 25, 2022); TAPS Comments, Docket No. AD22–5, at 7 (filed Apr. 25, 2022); TS Conductor Comments, Docket No. AD22–5, at 9–10 (filed Mar. 13, 2022); WATT/CEE Comments, Docket No. AD22–5, at 14 (filed Apr. 25, 2022); Electricity Canada Comments, Docket No. AD22–5, at 6 (filed Apr. 25, 2022). A transmission span is the distance between specific transmission support towers.

[28] Order No. 881, 177 FERC ¶ 61,179 at P 44.

[29] *Id.*

[30] *Id.*

[31] *See, e.g.,* IEEE Standard 738–2023, ''IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors,'' 2023 (IEEE 738); and CIGRÉ Technical Brochure 207, ''Thermal Behavior of Overhead Conductors, Working Group 22.12,'' 2002 (CIGRÉ 207).

[32] *See, e.g.,* IEEE Standard C2–2023, ''2023 National Electric Safety Code,'' 2023, at section 23.

[33] Lisa Sosna, et al., *Demonstration of Potential Data/Calculation Workflows Under FERC Order 881's Ambient-Adjusted Rating (AAR)*

Continued

confidence levels requires a balance between realizing the benefits of incorporating weather forecasts and ensuring that the estimate does not overestimate the thermal capability of the transmission line, which could create system management challenges for transmission providers and/or jeopardize reliability.

3. Variables That Impact Thermal Ratings of Transmission Lines

18. Thermal ratings are affected by a variety of factors, including ambient air temperatures, solar heating, and wind speed.

a. Ambient Air Temperature

19. Transmission line thermal ratings generally decrease with warmer ambient air temperatures and generally increase with cooler ambient air temperatures, because the heat generated within the conductor due to resistive losses dissipates to the environment more quickly at lower ambient temperatures.

b. Solar Heating

20. Transmission line thermal ratings generally decrease when exposed to more intense solar heating conditions and generally increase when exposed to less intense solar heating conditions, because lower solar heating allows the conductor to carry more power without overheating. Solar heating is most intense when there are clear-sky conditions, and the sun is at its peak position in the sky.

c. Wind Speed and Direction

21. Wind cools a transmission line, which dissipates the heat generated from resistive losses more quickly and results in greater transmission transfer capability on that line. Transmission line thermal ratings generally increase when wind speed is higher and when wind direction is perpendicular to a line and generally decrease when wind speed is lower and when wind direction is parallel to a line. According to research presented by Idaho National Laboratory at the Commission's 2019 DLR Workshop, consideration of wind speed and direction could theoretically increase transmission line ratings by more than 100% in certain periods.[34] In practice, the typical increase in transmission line ratings may be smaller than 100%, but it would still be significant, because consideration of forecast uncertainty and confidence levels for both wind speed forecasts and wind direction forecasts would reduce the potential rating increases. A higher confidence level would proportionally discount the impact of reflecting wind speed and direction on a transmission line rating.[35]

C. Incorporating Weather Variables Into Thermal Ratings

22. Because a variety of weather variables affect thermal ratings, DLRs can incorporate weather variables that ''reflect transfer capability even more accurately'' than static line ratings.[36] In addition to ambient air temperature, DLRs can incorporate weather variables and other inputs into the calculation of thermal ratings ''such as (but not limited to) wind, cloud cover, solar heating (beyond daytime/nighttime distinctions), precipitation, and transmission line conditions such as tension or sag.'' [37] Moreover, the use of sensors installed on or near the transmission line can provide localized and potentially more accurate weather forecasts when compared to large-area weather forecasts, such as those provided by the National Weather Service, further improving DLR accuracy.

23. DLR implementation requires making reliable short-term forecasts [38] at very specific locations. In DLR implementation, weather measurements and, potentially, other data from sensors are combined with data from the recent past to create short-term weather forecasts for the specific location of the transmission line. These short-term weather forecasts are the basis of the DLRs themselves.[39]

24. DLRs are implemented through the following steps: identifying candidate transmission lines; installing any needed sensors and data communication systems; forecasting short-term weather conditions; revising thermal ratings formulas; and validating thermal ratings and integrating them in an energy management system (EMS).[40]

1. Sensors and Their Use in DLRs

25. Generally, two types of sensors can be used to implement DLRs: (1) weather sensors that measure factors like wind speed, wind direction, and/or cloud cover; and (2) conductor sensors that measure the condition of the transmission line itself, such as conductor temperature, sag, or tension.

26. Sensors can be positioned either on the ground or on the transmission line. Each option has advantages and disadvantages.[41] For instance, sensors placed on a transmission line may require transmission line outages for installation and maintenance, while ground-based sensors can be easier to install and maintain. However, ground-based sensors are more vulnerable to physical tampering and could pose a security threat for safe operations.[42] Some DLR systems incorporate photo-spatial sensors (*e.g.,* light detection and ranging (LiDAR)) and/or line sensors installed on or close to the monitored transmission line.[43] The ideal placement of a sensor can depend upon the sensor technology and which variable the sensor is trying to measure. For example, optical fiber sensors that are placed inside a conductor can measure conductor properties but may not be capable of measuring ambient weather conditions.

27. The real-time data acquired from either type of sensor can provide many benefits to the DLR systems and the transmission providers using them. For example, data from sensors can provide real-time operational awareness to grid operators, helping to identify

Requirements, joint FERC/NOAA staff presentation at FERC's Software Conference at slide 24–25 (June 23, 2022), *https://www.ferc.gov/media/demonstration-potential-datacalculation-workflows-under-ferc-order-no-881s-ambient-adjusted.*

[34] Jake Gentle, et al., *Forecasting for Dynamic Line Ratings,* Idaho National Laboratory presentation at FERC DLR Workshop slide 13 (Sept. 10, 2019), *https://www.ferc.gov/sites/default/files/2020-09/Gentle-INL.pdf.*

[35] *See* Order No. 881, 177 FERC ¶ 61,179 at P 128 (acknowledging concerns about temperature forecast margins being too low or too high).

[36] *See id.* P 26.

[37] *See id.* P 7.

[38] Although clear-sky solar heating calculations are generally referred to as forecasts, they may be better thought of as ''determinations'' because they carry no forecast uncertainty. Total solar power along a transmission line can be calculated based on the location and orientation of a transmission line, at any time and day of the year. *See* Conseil International des Grands Réseaux Électriques/International Council of Large Electric Systems (CIGRE), Guide for Thermal Rating Calculations of Overhead Lines, Technical Brochure 601, Dec. 2014 (CIGRE TB 601). Thus, our use of ''forecast'' here when referring to clear-sky solar heating is not intended to indicate any expected forecast uncertainty about the determination of clear-sky solar heating.

[39] *See, e.g.,* Jake Gentle, et al., *Dynamic Line Ratings Forecast Time Frames,* Idaho National Lab (2023), Dynamic-Line-Rating-Forecasting-Time-Frames.pdf (inl.gov); *Managing Transmission Line Ratings,* Docket No. AD19–15–000, Technical Conference, Day 1 (Sept. 10, 2019), Tr. 29:1–3 (Joey Alexander, Ampacimon SA) (filed Oct. 8, 2019) (discussing a DLR project undertaken by Elia, Belgium's transmission system operator and noting that, ''they wanted to make sure they could implement a two-day ahead forecast of the DLR because that's what that market traded on''); *see also Managing Transmission Line Ratings,* Staff Report, Docket No. AD19–15–000, at 10 (issued Aug. 23, 2019) (''As mentioned earlier, forecasting of the relevant weather conditions and line ratings over some operationally useful period . . . is necessary for DLR implementation.'').

[40] *See* Order No. 881, 177 FERC ¶ 61,179 at P 7.

[41] *Managing Transmission Line Ratings,* Staff Report, Docket No. AD19–15–000, at 9 (issued Aug. 23, 2019).

[42] *Id.*

[43] *Id.* at 7–8.

unexpected changes in a transmission line's capacity. Data from sensors can also be used to verify the thermal rating calculated for the transmission line, a process known as ''ratings validation.'' Data from sensors can also help measure the accuracy of the local weather forecasts underlying DLRs and provide information with which to improve the forecasting methodology, a process known as ''forecast training.'' Both ratings validation and forecast training can improve thermal ratings over time. Moreover, forecast training can help transmission providers discover systemic patterns in local forecast errors and thus adjust their forecasting methods to improve local forecast accuracy. As a simplified example, a transmission provider may observe that actual wind speeds, as measured by a sensor, in a particular valley are consistently lower than the weather forecasts indicate for the broader area. In this case, the transmission provider could develop a ''trained'' forecast reflecting a lower localized wind speed forecast for that valley, which could be used to calculate the transmission line's thermal ratings more accurately.[44]

28. However, some weather elements can be incorporated into a transmission line rating without a sensor. For instance, in addition to ambient air temperature, initial outreach indicates that solar heating based on the sun's position and some forecasts of cloud cover can be incorporated into transmission line ratings without sensors.

29. The effective use of sensors to determine DLRs requires at least four key considerations: what type of sensors and where to place them; how many sensors are needed; how to configure them; and how to ensure physical security and cybersecurity. Sensor placement requires a careful assessment of the sensor type, the number of sensors needed, and the location for each of the sensors to be installed.

30. The appropriate quantity and configuration of sensors depends on the type of sensors used and the weather variables they measure. Weather-based DLR systems may incorporate real-time measurements and/or forecasts of wind conditions because wind conditions have the greatest effect on the thermal rating of a transmission line.[45] However, because wind speed and direction are highly variable and subject to local geographic differences,[46] real time measurements of wind conditions may require numerous sensors. As such, reflecting wind conditions in transmission line ratings can be costly because it requires installation and maintenance of sufficient local sensors and communications equipment.

31. Generally, placing more sensors at rating-limiting elements or spans ensures more granular data to calculate transmission line ratings.[47] Generally, placing fewer sensors can diminish the granularity and accuracy and may require transmission providers to interpolate the weather and transmission line data from sensors on other parts of the transmission line, which could be difficult or impractical, and factors such as varied terrain or turns in the transmission line could make this calculation potentially inaccurate. Varied terrain turns in the transmission line, and the length of the transmission line, each create the need for more sensors, but each sensor represents an additional cost. Thus, sensor placement can be more expensive for both transmission providers with longer transmission lines and those with transmission lines in hilly or mountainous areas.

32. DLR implementation also involves physical security and cybersecurity risks. Therefore, as with other transmission systems, protections must be put in place to ensure the physical security and cybersecurity of the communications equipment, computer hardware, and computer software required to integrate and manage DLR systems, which can include sensors and/or alternative data sources, and associated data in the transmission provider's EMS. DLR systems may rely upon numerous routable devices, each of which may be vulnerable to cyberattack. Physical security and cybersecurity protections must be installed to protect and ensure that the new sensor system is not tampered with or compromised. Moreover, transmission providers implementing DLRs may not be able to use the off-the-shelf computer systems, cloud solutions, and/or services offered by vendors.[48] Instead, transmission providers may have to build their own secure, on-premises computer systems, rely on services that comply with applicable North American Electric Reliability Corporation (NERC) Reliability Standards, and quickly adopt developing best practices to ensure that the DLR system is secure.

2. Incorporating Local Weather Forecasts Into DLRs

33. While DLRs that rely on weather forecasts may offer significant value, forecasting local weather may present several challenges, with related opportunities for solutions. First, because all transmission line ratings—including DLRs—depend upon the transmission line's most-limiting element, the location of the most-limiting element must be determined to identify which local weather forecast is needed. Further, changes in the local weather may change which of the weather-sensitive elements is most limiting.[49] However, while identifying limiting segments across a transmission line may appear conceptually challenging, a joint FERC/National Oceanic and Atmospheric Administration (NOAA) staff presentation concluded that determining the location of the most-limiting segment for purposes of AAR calculations can be relatively simple once the transmission line rating formula and weather data processing is established.[50]

34. Second, incorporating additional weather variables into transmission line ratings will require preparing forecasts for each variable, which may be more resource intensive. For example, due to increased variability and micro-geographic differences, forecasting wind speed and direction may require more

[44] Rating validation and forecast training do not necessarily have to use *weather* sensors; *conductor* sensors can also be used for these purposes. While conductor sensors do not measure weather variables directly, conductor sensor measurements nonetheless reflect the effects of real-time weather, and thus can be used to indirectly validate and train weather forecasts.

[45] WATT/CEE Comments, Docket No. AD22–5, at 14 (filed Apr. 25, 2022).

[46] Clean Energy Parties Comments, Docket No. AD22–5, at 12 (filed Apr. 25, 2022).

[47] For example, BPA explains that it paid $50,000 for each of its DLR sensors, and an additional $17,500 each for installation, in its DLR study with EPRI. BPA Comments, Docket No. AD22–5, at 9 (filed Apr. 25, 2022).

[48] *See, e.g.,* PPL Comments, Docket No. AD22–5, at 17–18 (filed Apr. 25, 2022).

[49] For example, if the wind were to stop blowing across one segment of a transmission line and were to start blowing across another segment, the former segment might become the most limiting element. Therefore, thermal ratings for each segment on a transmission line must be frequently redetermined based on up-to-date weather forecasts, and thus the most limiting element or transmission line span may vary.

[50] *See, e.g.,* Lisa Sosna, *et al., Demonstration of Potential Data/Calculation Workflows Under FERC Order 881's Ambient-Adjusted Rating (AAR) Requirements,* joint FERC/NOAA staff presentation at FERC's Software Conference slides 10, 14 and 26 (June 23, 2022), *https://www.ferc.gov/media/demonstration-potential-datacalculation-workflows-under-ferc-order-no-881s-ambient-adjusted* (FERC/NOAA staff evaluated ratings at numerous elements on each line they demonstrated AAR calculations for, adopting the rating at the most conservative element as the rating of the overall line; ''Our approach proved to support very quick calculation of line ratings despite the large number of rating [elements].''). In theory, establishing such a process could be more complicated for DLR systems that consider additional weather variables.

analysis from meteorologists than ambient air temperature forecasts.

35. Third, relying on weather forecasts for calculating transmission line ratings exposes transmission providers to forecasting uncertainty. In most instances, reductions in forecasted transmission line ratings can be identified hours or days ahead of the operating hour, giving transmission providers and market participants time to act to ensure flows do not exceed transmission line ratings. However, in some instances, when changes in forecasts happen at or close to the operating hour and cause potential reliability concerns, transmission system operators may need to issue curtailment or redispatch instructions to manage the shortage in transmission capability, which could be operationally similar to transmission line derates that do not involve DLRs. This challenge can be managed through specification of appropriate forecast confidence levels and related forecast margins.[51] Where weather conditions are particularly challenging to forecast, achieving the necessary confidence levels may require significant forecast margins that may make DLRs impractical, even on heavily congested transmission lines. We discuss this challenge further below in section IV.A.6. Confidence Levels.

3. Current Use and Benefits of DLRs

36. As discussed further in the Need for Reform section below, numerous DLRs have already been deployed domestically and internationally, with resulting benefits to the transmission system and customers, including increased transmission capacity, reduced congestion, and reduced costs.

D. Pro forma Transmission Scheduling and Congestion Management Practices

37. As relevant here, transmission line ratings are used by transmission providers [52] in determining: (1) whether a transmission service request is approved or denied; and (2) when and how transmission service must be curtailed or redispatched to protect reliability or interrupted to provide service to a higher-priority customer.[53]

1. How Transmission Service Is Procured

38. Because the preliminary proposals discussed herein—both for identifying the congested transmission lines that would be subject to a DLR requirement and the transmission services that would be impacted by such a DLR requirement—relate to the details of transmission service and congestion management practices under the *pro forma* OATT, we provide an overview of those services and practices.

a. Transmission Service Under the pro forma OATT

39. There are two types of transmission service provided under the *pro forma* OATT: (1) point-to-point transmission service; and (2) network integration transmission service.

40. Point-to-point transmission service is the reservation and transmission of capacity and energy from the point(s) of receipt to the point(s) of delivery.[54] Point-to-point transmission service is offered on a firm and non-firm basis.[55] When evaluating a point-to-point transmission service request, the transmission provider determines whether there is sufficient available transfer capability (ATC) from a specified point-of-receipt to a specified point-of-delivery. ATC can be calculated for any path on the transmission system to determine if the system has available capacity to reliably accommodate new transmission customers, using as inputs total transfer capability (TTC) and existing transmission commitments (ETC) on that path, as well as the amount of transfer capability reserved as part of the capacity benefit margin (CBM) and transmission reliability margin (TRM).[56] Specifically, ATC is calculated as: ATC = TTC − ETC − CBM − TRM.[57]

41. The transmission line rating of a given transmission line is the primary input into determining its TTC and, thus, is a key determinant of the transmission line's ATC. ATC on a path is not a single, static value; rather, it has different values based on the requested point-to-point transmission service duration (hourly, daily, weekly, monthly, annual), time (when service is requested to start and end), and priority (firm or non-firm). For example, firm annual ATC starting January 1 of a given year might be zero because of high levels of ETC during the summer months, while firm monthly, weekly, and daily ATC on the same path may be higher during non-summer months.

42. In the event a transmission provider is unable to accommodate a request for long-term (*i.e.,* with a term of one year or more) firm point-to-point transmission service, the *pro forma* OATT establishes various obligations on the transmission provider, including obligations related to redispatch and conditional firm transmission service. First, such a transmission provider must (under certain conditions) use due diligence to provide redispatch from its own resources and not unreasonably deny self-provided redispatch or redispatch arranged by a transmission customer from a third party.[58] Second, such a transmission provider must offer to provide firm transmission service with the condition that it may curtail the service prior to the curtailment of other firm transmission service for a specified number of hours per year or during specified system condition(s) (*i.e.,* conditional firm transmission service).[59]

43. Network integration transmission service or network service allows a network customer to use the transmission system in a manner comparable to how the transmission provider uses its own transmission system to serve its native load. Specifically, network service allows a network customer's network resources (generators, firm energy purchases, etc.) to be integrated and economically dispatched to serve its network load.

[51] A forecast margin is a margin by which a forecast of an expected parameter is adjusted (up or down, depending on the circumstance) to provide sufficient confidence that the actual parameter value will not be less favorable than the forecast. *See, e.g.,* Order No. 881, 177 FERC ¶ 61,179 at P 128.

[52] In this ANOPR, we use transmission provider to mean any public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce. 18 CFR 37.3. Therefore, unless otherwise noted, ''transmission provider'' refers only to public utility transmission providers. The term ''public utility'' as defined in the FPA means ''any person who owns or operates facilities subject to the jurisdiction of the Commission under this subchapter.'' 16 U.S.C. 824(e).

[53] Transmission line ratings are also used by transmission providers for other purposes, including as part of transmission planning.

[54] *Pro forma* OATT, section 1.37 (Point-To-Point Transmission Service).

[55] *Id.; id.* section 13.6 (Curtailment of Firm Transmission Service).

[56] Section 37.6 of the Commission's regulations defines CBM as ''the amount of TTC preserved by the transmission provider for load-serving entities, whose loads are located on that Transmission Provider's system, to enable access by the load-serving entities to generation from interconnected systems to meet generation reliability requirements, or such definition as contained in Commission-approved Reliability Standards.'' 18 CFR 37.6(b)(1)(vii). Section 37.6 defines TRM as ''the amount of TTC necessary to provide reasonable assurance that the interconnected transmission network will be secure, or such definition as contained in Commission-approved Reliability Standards.'' *Id.* § 37.6(b)(1)(viii).

[57] *Preventing Undue Discrimination & Preference in Transmission Serv.,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119, at P 209, *order on reh'g,* Order No. 890–A, 72 FR 12266 (Mar. 15, 2007), 121 FERC ¶ 61,297 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[58] *Pro forma* OATT, section 15.4(b).

[59] *Id.* section 15.4(c); *id.* section 19.3 (System Impact Study Procedures).

44. Network service is provided from a fleet of network resources to a set of network loads rather than from a single point-of-receipt to a single point-of-delivery.[60] As such, when evaluating network integration transmission service requests, a transmission provider performs load-flow modeling of various anticipated dispatches on its system and compares the modeled flows on each impacted transmission line to the transmission line's rating.[61]

b. Congestion Management Under the pro forma OATT

45. Congestion is managed under the *pro forma* OATT according to service priority. While there are some exceptions, the typical order of service priority is: (1) network integration transmission service and long-term (one year or longer) firm point-to-point; (2) short-term (less than one year) firm point-to-point; (3) conditional firm transmission service and secondary service; and (4) non-firm point-to-point.[62] Under the *pro forma* OATT, network integration transmission service is subject to curtailment or redispatch, while point-to-point transmission service is subject to curtailment or interruption.[63] Under the *pro forma* OATT, curtailment and redispatch are typically done for reliability reasons, whereas interruption is typically conducted for economic reasons. Prior to curtailing network integration transmission service and/or long-term firm point-to-point service, transmission providers may, however, be required to redispatch network customers' resources and the transmission provider's own resources, on a least-cost and non-discriminatory basis and without respect to ownership of such resources, to relieve a transmission constraint or maintain reliability.[64]

c. Transmission Scheduling and Congestion Management in the RTOs/ISOs

46. All RTO/ISO tariffs reflect Commission-approved variations from the *pro forma* OATT provisions. In RTOs/ISOs, transmission service is typically provided as part of the security-constrained economic dispatch (SCED) and security-constrained unit commitment (SCUC) processes performed by the market software. As part of SCED and SCUC, the market software performs a constrained optimization based on supply offers and demand that minimizes production costs and ensures (among other things) that flows on transmission lines do not exceed transmission line ratings. Therefore, transmission line ratings are a primary factor in the optimization process and efficient pricing.[65]

2. Existing Data Reporting on Congestion, or Proxies of Congestion

47. The availability of data measuring the cost of congestion on the transmission system, or proxies that could be used to estimate the cost of congestion, varies between RTO/ISO and non-RTO/ISO regions.

a. RTOs/ISOs

48. In RTO/ISO markets, at least two types of congestion metrics are computed and publicly reported. First, as part of solving their real-time and day-ahead markets, RTOs/ISOs compute and publish locational marginal prices (LMP) that include a ''congestion component,'' indicating how much congestion has increased (or decreased) a locational price at a node compared to reference node(s).[66] The congestion component of an LMP for a node reflects the extent to which an additional increment of load at that node would, because of binding transmission constraints, need to be supplied by resources with different marginal costs than the resources available to serve additional increments of load at the reference node(s).[67] For example, if an RTO/ISO must ramp up a higher-cost peaking unit in lieu of a lower-cost baseload unit due to a transmission constraint, the additional incremental cost of the peaking unit would be reflected in the congestion component of LMP. Second, as part of solving their real-time and day-ahead markets, RTOs/ISOs compute and publish the marginal cost of each transmission flow constraint, sometimes called the ''shadow prices'' of those constraints. These shadow prices reflect the marginal production cost savings that would occur if the flow limit on a constraint were relaxed by one MW. Shadow prices are used to calculate the marginal congestion component of LMP.[68] LMPs and shadow prices reflect *marginal* rather than *total* costs.

b. Non-RTO/ISO Regions

49. Non-RTO/ISO regions do not publish nodal prices in the same manner as RTOs/ISOs, which can result in less public information available on congestion costs outside of RTOs/ISOs. However, practices to manage congestion and redispatch of internal resources may be used to assess congestion costs in non-RTO/ISO regions.

i. ATC and Constrained Posted-Paths

50. Section 37.6 of the Commission's regulations requires transmission providers to calculate and post certain information, including ATC and TTC.[69] Such calculations and postings must be made for the following posted paths: (1) any control-area-to-control area interconnection; (2) any path for which service has been denied, curtailed, or interrupted for more than 24 hours in the past 12 months; and (3) any path for which a transmission customer has requested that ATC or TTC be posted.[70] For all posted paths, ATC, TTC, CBM, and TRM values must be automatically posted.[71] These postings allow potential transmission customers to: (1) make requests for transmission services offered by transmission providers, request the designation of a network resource, and request the termination of

[60] *Pro forma* OATT, pt. III (Network Integration Transmission Service Preamble); *id.* section 28 (Nature of Network Integration Transmission Service).

[61] *Pro forma* OATT, section 32 Additional Study Procedures For Network Integration Transmission Service Requests, attach. C (Methodology To Assess Available Transfer Capability), and attach. D (Methodology for Completing A System Impact Study).

[62] *Id.* section 13.6 (Curtailment of Firm Transmission Service); *id.* section 14.7 (Curtailment or Interruption of Service); *id.* section 33 (Load Shedding and Curtailments).

[63] The *pro forma* OATT defines curtailment as a reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions. *Id.* section 1.8 (Curtailment). The *pro forma* OATT defines interruption as a reduction in non-firm transmission service due to economic reasons pursuant to section 14.7. *Id.* section 1.16 (Interruption).

[64] *Id.* section 33.2 (Transmission Constraints).

[65] While SCED and SCUC processes consider power flow over the interties, RTOs/ISOs do not typically optimize ATC in the same manner as internal locations.

[66] *See, e.g.,* ISO–NE, *FAQs: Locational Marginal Pricing,* (Feb. 2024), *https://www.iso-ne.com/participate/support/faq/lmp*; NYISO, *LBMP In-Depth Course: Congestion Price Component* 4–15 (Nov. 2022), *https://www.nyiso.com/course-materials*; MISO, *MTEP18: Book 4 Regional Energy Information,* at 8 (2018).

[67] *See* NYISO, *LBMP In-Depth Course: Congestion Price Component* 19–21 (Nov. 2022), *https://www.nyiso.com/course-materials*; FERC, *Energy Primer: A Handbook for Energy Market Basics* 69–71 (2024), *https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf.*

[68] The MISO tariff and the CAISO Business Practice Manual for Definitions and Acronyms both define ''shadow price'' as ''the marginal value of relieving a particular constraint.'' *See* MISO, MISO Tariff, Module A—Common Tariff Provisions, Definitions—S (Shadow Price), *https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/*; CAISO, *Business Practice Manual for Definitions & Acronyms* 128, (Jan. 21, 2023), *https://bpmcm.caiso.com/BPM%20Document%20Library/Definitions%20and%20Acronyms/2023-Jan31_BPM_for_Defintions_and_Acronyms_V20_Redline.pdf.*

[69] 18 CFR 37.6.

[70] *Id.* § 37.6(b)(1)(i).

[71] *Id.* § 37.6(b)(3).

the designation of a network resource; (2) view and download information regarding the transmission system necessary to enable prudent business decision making; (3) post, view, upload and download information regarding available products and desired services; (4) identify the degree to which transmission service requests or schedules were denied or interrupted; (5) obtain access to information to support ATC calculations and historical transmission service requests and schedules for various audit purposes; and (6) make file transfers and automate computer-to-computer file transfers and queries.[72]

51. Section 37.6(b)(1)(ii) of the Commission's regulations defines constrained posted paths as any posted paths that have ATC less than or equal to 25 percent of TTC at any time during the preceding 168 hours or for which ATC has been calculated to be less than or equal to 25 percent of TTC for any period during the current hour or the next 168 hours.[73] For all constrained posted paths, additional detailed information must be made available upon request.[74] This includes ''all data used to calculate ATC [and] TTC,'' including relevant transmission line ratings, identification of limiting element(s), the cause of the limit (*e.g.,* thermal, voltage, stability), and load forecast assumptions.[75]

52. Under these requirements, depending on whether the paths are constrained or unconstrained, transmission providers are required to post firm and non-firm ATC and related data for many different timeframes (*e.g.,* daily, monthly, seasonally, annually) for different durations into the future ranging from daily ATC for the next day to annual ATC as far out as 10 years (in certain circumstances for some constrained posted paths).[76] Other posting requirements (including posting of hourly ATC) apply to non-firm ATC. All such postings are typically made to the transmission providers' Open Access Same-Time Information System (OASIS) site.

ii. Redispatch Costs

53. Under the *pro forma* OATT, transmission providers may redispatch resources due to the existence of transmission constraints in certain circumstances.[77] Because non-RTO/ISO regions do not publish nodal prices that reflect congestion costs, the cost of redispatching resources is less transparent.[78] Nonetheless, redispatching of resources in non-RTO/ISO regions to manage congestion may be comparable to the practices in RTOs/ISOs in that both are tasked with reliably serving wholesale transmission customers at least cost.

III. The Potential Need for Reform

54. As a result of the continued development of DLR technology, the record gathered in the NOI, and outreach conducted since the issuance of the NOI, we believe that it is appropriate to examine whether transmission line ratings that fail to reflect forecasts of solar heating and wind speed and direction result in sufficiently accurate transmission line ratings and whether reforms may be necessary to improve the accuracy of transmission line ratings and ensure transparency of their development and implementation. Without these reforms, we believe that transmission line ratings may be insufficiently accurate and may unjustly and unreasonably increase the cost to reliably serve wholesale electric customers by forgoing many potential benefits. As the Commission has previously found, inaccurate transmission line ratings result in Commission-jurisdictional rates that are unjust and unreasonable.[79] Accordingly, we preliminarily find that transmission line ratings that do not account for solar heating and wind conditions may result in rates and practices that are unjust, unreasonable, unduly discriminatory or preferential. We begin with a discussion about existing uses of DLRs and their associated benefits before discussing potential reforms.

A. Demonstrated DLR Benefits

55. DLRs have been deployed nationally and internationally, with resulting benefits to the transmission system and customers, including increased transmission capacity, reduced congestion, and reduced costs. Existing DLR projects and data demonstrating their benefits strengthen the potential need for reform.

1. U.S. Examples

56. In the United States, some transmission providers and system operators report using DLR systems to curb congestion, increase transmission capacity, and reduce costs. Below, we detail four specific examples of DLR use. These examples illustrate how DLRs can more accurately reflect the capability of a transmission facility and result in cost savings where congestion is decreased due to increased transmission capability.

57. First, PPL, which owns transmission facilities in PJM, has spent approximately $1 million implementing DLRs, using 18 sensors on more than 31 miles of three 230 kV transmission line segments, and has integrated DLRs for these transmission lines into PJM's real-time and day-ahead markets.[80] By contrast, PPL states that it internally estimated the cost to reconductor the Susquehanna-Harwood double-circuit line to be approximately $12 million.[81] PPL reports that, based on 2022 data, implementing DLR on these three transmission lines produced normal ratings gains above AARs of approximately 17% and emergency ratings gains above AARs ranging from 8.5% to 16.5%.[82] PPL further reports that deploying DLR on two Susquehanna-Harwood lines eliminated congestion, which was $12 million per year in the summer of 2022, and that, deploying DLR on the Juniata-Cumberland transmission line decreased congestion costs from approximately $66 million in the winter of 2021–22 to approximately $1.6 million in the winter of 2022–23. PPL explains that it aims to implement DLR

[72] *Id.* § 37.6(a).

[73] *Id.* § 37.6(b)(1)(ii).

[74] *Id.* § 37.6(b)(2)(ii).

[75] *Id.*

[76] *Id.* § 37.6(b)(3).

[77] Section 33.2 of the *pro forma* OATT provides that during any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. Section 33.2 of the *pro forma* OATT provides that to the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resource. Section 33.2 of the *pro forma* OATT further provides that any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

[78] Any redispatch costs are allocated proportionately to the load ratio share of the transmission provider and network customers. *See pro forma* OATT, section 33.3 (Cost Responsibility for Relieving Transmission Constraints).

[79] Order No. 881, 177 FERC ¶ 61,179 at P 3.

[80] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies* 11 (Oct. 2021), *https://inl.gov/content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf*; T&D World, *PPL Electric Utilities Wins 95th Annual Edison Award* (June 2023), *https://www.tdworld.com/electric-utility-operations/article/21267742/ppl-electric-utilities-wins-95th-annual-edison-award*.

[81] PPL Comments, Docket No. AD22–5, at 14–15 (filed Apr. 25, 2022).

[82] PPL Supplemental Comments, Docket No. AD22–5, at 2–4 (filed Feb. 9, 2024).

on five additional transmission lines by the end of 2024.[83]

58. PJM notes that, during Winter Storm Elliott, DLRs on the previously mentioned PPL transmission lines proved higher than the AARs, and that, had PJM not had the higher DLRs, PJM would have had to redispatch the system to maintain reliability. PJM adds that such action would have been very difficult under the critical operating conditions caused by the winter storm.[84]

59. In a DLR deployment study of a single 115 kV transmission line owned by National Grid in Massachusetts, DLRs were found to increase transmission capacity by approximately 16% above AARs (excluding periods when DLRs were lower than AARs). However, the project also recorded that DLRs were below AARs 22% of the time in the summer and 27% of the time in the winter (at times when wind speed was low and the AAR would have been overstated).[85] The DLR sensors were reported as ''easy to install, reliable, and effective at reporting periods of either excess or limited capacity.'' [86]

60. A Department of Energy (DOE) report described implementation of DLRs using tension sensors along five 345 kV transmission lines and three 138 kV transmission lines by Oncor Electric Delivery Company's (Oncor), a transmission owner in ERCOT. The report noted that DLRs increased the available capacity of the lines by between 6% and 14% beyond the transmission lines' AARs, on average. As described in the report, Oncor determined that the cost of installing DLRs ranged from $16,000 to $56,000 per mile, depending on the type of transmission towers upon which DLR equipment was installed.[87] The report noted that installation costs in this instance totaled approximately $4.8 million and that DLR system costs are often only a fraction of the cost of reconductoring or rebuilding a transmission line.[88]

61. In August 2021, Duquesne Light Company (Duquesne), a transmission owner in PJM, partnered with LineVision on a DLR pilot project.[89] The pilot project installed DLRs on 345 kV lines in southwestern Pennsylvania and increased the lines' available capacity by 25%, on average. In 2022, Duquesne expanded the pilot program and installed sensors to also monitor 138 kV transmission lines, reporting an average transmission line rating increase of 25%, which, it asserts, has helped to make way for more renewable energy sources.[90]

62. In addition, a recent report on an initial deployment of DLRs by subsidiaries of AES Corporation in Indiana and Ohio shows that estimated costs to implement DLRs on the studied transmission lines are generally lower than reconductoring alternatives and that DLRs can be implemented more quickly than reconductoring.[91]

2. International Examples

63. Many transmission providers elsewhere in the world have similar, or greater, levels of experience with DLRs as those in the United States, with some running pilot projects and others using DLRs in operations. Like the U.S. examples cited above, these projects illustrate the potential for DLRs to more accurately estimate transmission transfer capability and reduce costs due to decreased congestion.

64. Elia (Belgium's system operator) uses DLRs on 33 transmission lines that range from 70 kV to 380 kV.[92] A representative from Elia stated the following at a September 10, 2021 Commission workshop: ''the lines equipped with [DLRs] are more reliable than other lines'' and that Elia knows ''more about those lines than any other lines in the grid.'' [93] RTE, France's transmission operator, used DLR to integrate wind power generation and avoid a $30 million transmission line replacement.[94]

65. Austria has installed DLR on 15% of its transmission system, leading to almost $17 million in congestion cost savings in 2016.[95] The Slovenian system operator has used DLR on each span of 31 transmission lines since 2016, increasing capacity an average of 22%.[96] A joint project between the University of Palermo and Terna Rete Italia SPA to install 90 DLR monitors in Italy saved roughly $1.25 million per transmission line per year, with a payback period of two years or less.[97]

66. In 2020, LineVision and the European Commission's FARCROSS consortium, a project to boost cross-border transmission in the European Union, announced a partnership to install DLR in Hungary, Greece, Slovenia, and Austria.[98]

67. The United Kingdom's National Grid has installed DLR on a 275 kV circuit in Cumbria, with estimated savings of £1.4 million per year.[99] In Scotland, SP Energy Networks installed DLR at a cost of approximately $240,000 to increase capacity on two circuits and avoid the need for a transmission line rebuild that would have cost $2.25 million, roughly 10 times the cost of DLR installation.[100]

68. Analysis of four AltaLink transmission lines in Canada found

[83] *Id.*

[84] PJM Supplemental Comments, Docket No. AD22–5, at 2 (filed Jan. 17, 2024).

[85] K. Engel, J. Marmillo, M. Amini, H. Elyas, B. Enayati, *An Empirical Analysis of the Operational Efficiencies and Risks Associated with Static, Ambient Adjusted, and Dynamic Line Rating Methodologies* 3, 8 (Jul. 2, 2021), *https://cigre-usnc.org/wp-content/uploads/2021/11/An-Empirical-Analysis-of-the-Operational-Efficiencies-and-Risks-Associated-with-Line-Rating-Methodologies.pdf.*

[86] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies* 8 (Oct. 2022), *https://inl.gov/content/uploads/2023/03/A-Guide-to-Case-Studies-for-Grid-Enhancing-Technologies.pdf.*

[87] Warren Wang and Sarah Pinter, U.S. Dept. of Energy, *Dynamic Line Rating Systems for Transmission Lines* at 33, U.S. Dept. of Energy (Apr. 2014), *https://www.energy.gov/sites/prod/files/2016/10/f34/SGDP_Transmission_DLR_Topical_Report_04-25-14.pdf.*

[88] *Id.*

[89] Duquesne, *Duquesne Light Company Investing in New Technology to Enhance Grid Capacity and Reliance,* NewsRoom (Aug. 2021), *https://newsroom.duquesnelight.com/duquesne-light-company-investing-in-new-technology-to-enhance-grid-capacity-and-reliance.*

[90] LineVision, Inc, *Duquesne Light Company Further Enhances Transmission Capacity, Reliability with Grid-Enhancing Technology* (Aug. 2022), *https://www.linevisioninc.com/news/duquesne-light-company-further-enhances-transmission-capacity-reliability-with-grid-enhancing-technology.*

[91] AES Corporation and LineVision, Inc., *Lessons from First Deployment of Dynamic Line Ratings* (Apr. 2024), *https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf.* We understand the report to refer to The Dayton Power and Light Company as AES Ohio and Indianapolis Power & Light Company as AES Indiana, each a subsidiary of AES Corporation.

[92] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies* 33 (Dec. 2022), *https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_64025.pdf.*

[93] *Workshop to Discuss Certain Performance-based Ratemaking Approaches,* Docket No. RM20–10, Technical Video Conference (Sept. 10, 2021), Tr. 240:9–13 (Victor le Maire, Elia System Operator) (filed Oct. 13, 2021).

[94] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies,* at 13 (Dec. 2022).

[95] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies,* at 22 (Oct. 2022).

[96] Špela Vidrih, Andrej Matko, Janko Kosmač, Tomaž Tomšič, Aleš Donko, *Operational Experiences with the Dynamic Thermal Rating System,* at 8, 2d South East European Regional CIGRE Conference, Kyiv (2018).

[97] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies,* at 18 (Oct. 2022).

[98] T&D World, *LineVision Announces EU-Funded Projects with European Utilities* (Apr. 14, 2020), *https://www.tdworld.com/overhead-transmission/article/21128758/linevision-announces-eu-funded-projects-with-european-utilities.*

[99] LineVision, *National Grid installs LineVision's Dynamic Line Rating sensors to expand the capacity of existing power lines,* (Oct. 2022), *https://www.linevisioninc.com/news/national-grid-installs-linevisions-dynamic-line-rating-sensors-to-expand-the-capacity-of-existing-power-lines.*

[100] Idaho National Laboratory, *A Guide to Case Studies of Grid Enhancing Technologies,* at 28 (October. 2022).

DLRs were higher than static transmission line ratings "up to 95.1% of the time, with a mean increase of 72% over a static rating." [101] Moreover, DLRs were higher than seasonal ratings 76.6% of the time, with an average capacity improvement of 22% over static ratings.[102]

B. Consideration of Reforms

69. We are considering reforms that would require implementation of certain DLR practices, including: requiring transmission line ratings to reflect solar heating based on the sun's position and forecastable cloud cover; requiring transmission line ratings to reflect forecasts of wind conditions—wind speed and wind direction—on certain transmission lines; and enhancing data reporting practices to identify candidate transmission lines for the wind requirement in non-RTO/ISO regions. Such reforms may ensure that transmission line ratings result in jurisdictional rates that are just and reasonable.

70. In Order No. 881, the Commission found that transmission line ratings, and the rules by which they are established, are practices that directly affect the rates for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce (hereinafter referred to collectively as "wholesale rates").[103] The Commission further found that, because of the relationship between transmission line ratings and wholesale rates, inaccurate transmission line ratings result in wholesale rates that are unjust and unreasonable.[104] Acting pursuant to FPA section 206, the Commission concluded that certain revisions to the *pro forma* OATT and the Commission's regulations were necessary to ensure just and reasonable wholesale rates.[105]

71. In Order No. 881, the Commission recognized that, in addition to ambient air temperatures and daytime/nighttime solar heating, other weather conditions such as wind, cloud cover, solar heating intensity, precipitation, and transmission line conditions such as tension and sag, can affect the amount of transfer capability of a given transmission facility. The Commission explained that incorporating these additional inputs provides transmission line ratings that are closer to the true thermal transmission line limits than AARs.[106]

72. We preliminarily find that transmission line ratings that do not reflect solar heating based on the sun's position and up-to-date forecasts of forecastable cloud cover may result in unjust and unreasonable wholesale rates. We further preliminarily find that transmission line ratings that do not reflect up-to-date forecasts of wind conditions on certain transmission lines may also result in unjust and unreasonable wholesale rates. We seek comment on both of these preliminary findings.

73. We also preliminarily find that transmission line ratings that better reflect solar heating and, where appropriate, wind conditions would result in more accurate system transfer capability, thereby resulting in just and reasonable rates. As the Commission noted in Order No. 881, increasing transfer capability will, on average, reduce congestion costs because transmission providers will be able to import less expensive power into what were previously constrained areas, resulting in cost savings, as discussed above, and wholesale rates that avoid unnecessary congestion costs.[107] For example, as discussed above, PPL's implementation of DLRs on just two of its transmission lines reduced annual congestion costs by approximately $77 million annually.[108]

74. The use of DLRs may also provide benefits to customers by mitigating the need for more expensive upgrades. PPL's internal estimate to reconductor the Susquehanna-Harwood double-circuit line discussed above was approximately $12 million. In contrast, the cost to install DLRs on that line was less than $500,000.[109] In addition, a recent report on an initial deployment of DLRs by subsidiaries of AES Corporation compares estimated costs and implementation times of DLR deployment and reconductoring.[110] For a 345 kV transmission line in the AES Indiana footprint located in an area where significant load growth was expected, the cost to reconductor the transmission line was estimated to be $590,000 per mile, while the cost for DLR implementation was estimated to be $45,000 per mile.[111] The implementation time for reconductoring was estimated to be two years while the implementation for DLR was estimated to be nine months. For a 69 kV transmission line in the AES Ohio footprint that was experiencing regular thermal overload, the cost for full reconductoring was estimated to be $1.63 million, while the cost for DLR with targeted reconductoring was estimated to be $390,000.[112] The implementation timelines were two years for full reconductoring and one year for DLR with targeted reconductoring.

75. Likewise, the ability to increase transmission flows into load pockets may reduce a transmission provider's reliance on local reserves inside load pockets. This may reduce local reserve requirements and the costs to maintain that required level of reserves, which, in turn, may result in cost reductions and wholesale rates that avoid unnecessary congestion costs.[113]

76. DLRs can also provide reliability benefits by increasing the transfer capability on the existing transmission system in a way that provides system operators with more options during stressed system conditions. For example, as PJM explained, the presence of DLRs on its system during Winter Storm Elliott contributed to system reliability because the higher transmission line ratings allowed it to avoid re-dispatching its system.[114] DLR systems also give transmission providers a more complete picture of how the system is operating, particularly in contingency situations, which allows transmission providers to maximize their system's performance while maintaining a safe, reliable, and efficient system.[115] DLRs can also improve reliability by monitoring the condition of transmission lines and alerting utilities to hazardous conditions or potential failures on transmission lines, which may otherwise go

[101] Bishnu P. Bhattarai, Jake P. Gentle, Timothy McJunkin, Porter J. Hill, Kurt S. Myers, Alexander W. Abboud, Rodger Renwick, & David Hengst, *Improvement of Transmission Line Ampacity Utilization by Weather-Based Dynamic Line Rating,* IEEE Transactions on Power Delivery 1853, 1861 (2018), *https://doi.org/10.1109/TPWRD.2018.2798411*.

[102] *Id.* at 1853, 1861.

[103] Order No. 881, 177 FERC ¶ 61,179 at P 29.

[104] *Id.*

[105] *Id.*

[106] *Id.* P 36.

[107] *Id.* P 34 ("Such congestion cost changes and related overall price changes will more accurately reflect the actual congestion on the system, leading to wholesale rates that more accurately reflect the cost the wholesale service bring provided."); *see also supra* section III.A.1.

[108] *See supra* P 57.

[109] *See* PPL Comments, Docket No. AD22–5, at 14–15 (filed Apr. 25, 2022).

[110] AES Corporation and LineVision, Inc., *Lessons from First Deployment of Dynamic Line Ratings* (Apr. 2024), *https://www.aes.com/sites/aes.com/files/2024-04/AES-LineVision-Case-Study-2024.pdf.* We understand the report to refer to The Dayton Power and Light Company as AES Ohio and Indianapolis Power & Light Company as AES Indiana, each a subsidiary of AES Corporation.

[111] *Id.* at 14.

[112] *Id.* at 18.

[113] Order No. 881, 177 FERC ¶ 61,179 at P 34.

[114] *See supra* P 58.

[115] *See* DOE Comments, Docket No. AD22–5, Attachment A at 58 (filed Apr. 25, 2022); AES Corporation and LineVision, Inc., *Lessons from First Deployment of Dynamic Line Ratings,* at 5–6 (Apr. 2024).

undetected.[116] In addition, DLRs with certain sensors, such as LiDAR, can support public safety by providing for greater situational awareness by monitoring the clearance of transmission lines from the ground or nearby vegetation and providing data to assist in wildfire prevention strategies, including when to clear vegetation and when to upgrade equipment.[117]

77. The Commission also explained that decreasing transfer capability when it is overstated can avoid placing transmission lines at risk of inadvertent overload and can signal to the market that more generation and/or transmission investment may be needed in the long term.[118]

78. Finally, we preliminarily find that certain transparency reforms are necessary to ensure accurate transmission line ratings. As discussed below, the record indicates a lack of transparency for congestion costs in non-RTO/ISO regions. Understanding if, and how much, congestion may exist on a transmission line is essential to understanding whether that transmission line may benefit from the preliminary proposals in this rulemaking. As the Commission explained in Order No. 881, if a stakeholder does not know the basis for a given transmission line rating, particularly for a transmission line that frequently binds and elevates prices, it cannot determine whether the transmission line rating is accurately calculated.[119] We seek comment on this preliminary finding.

IV. Potential Reforms and Request for Comment

A. Potential Transmission Line Ratings Reforms and Request for Comment

79. As detailed above in section II.C.3. Current Use of DLRs and below in sections IV.A.2. Potential Solar Requirement and IV.A.3. Potential Wind Requirement, the current record suggests that DLRs can result in more accurate transmission line ratings [120] and significant benefits, including cost savings, through increased transfer capability. Specifically, we preliminarily find that the benefits of more accurate transmission line ratings outweigh the cost of implementation for DLRs that reflect more detailed solar heating based on the sun's position and forecastable cloud cover and, for certain transmission lines, that reflect forecasts of wind conditions. The applicability of the solar and wind requirements proposed below—applying a solar requirement for all transmission lines and a wind requirement for only certain lines—follows our understanding from outreach that reflecting solar heating based on the sun's position and forecastable cloud cover can be done without installing sensors and that reflecting wind conditions likely requires sensors. We seek comment on the proposed framework, as discussed below.

80. As noted above, in Order No. 881, the Commission, in effect, required RTOs/ISOs to be able to accept DLRs.[121] We do not propose to change this requirement here.

1. Framework for a Potential Requirement

81. We preliminarily propose a DLR framework for reforms to improve the accuracy of transmission line ratings.[122] These reforms would require transmission providers to implement DLRs that—on all transmission lines—reflect solar heating, based on the sun's position and forecastable cloud cover, and—on certain transmission lines—reflect forecasts of wind speed and wind direction. Thus, the proposed DLR framework sets forth both a solar requirement and a wind requirement. Additionally, the reforms would ensure transparency into the development and implementation of transmission line ratings and would enhance data reporting practices related to congestion in non-RTO/ISO regions to identify candidate transmission lines for the wind requirement. Under the proposed framework, these requirements would be subject to certain exceptions and/or implementation limits, as detailed below.

82. The NOI asked whether other weather conditions should be part of a potential DLR requirement.[123] However, there appears to be neither a strong record of the impact of other non-wind/non-solar weather conditions on transmission line ratings nor a standard for incorporating those weather conditions into transmission line ratings, as there is for solar heating and wind conditions (*e.g.,* IEEE 738 and CIGRE TB 299).[124] Thus, we do not propose to include such other variables in the proposed framework. We seek comment on the impact of non-wind/non-solar weather conditions on transmission line ratings, relevant standards associated with those weather conditions, and whether and how the Commission should require consideration of other weather conditions in its proposed rule.

2. Potential Solar Requirement

83. We preliminarily propose to require that all transmission line ratings used for evaluating transmission service that ends not more than 10 days after the transmission service request date (hereinafter ''near-term transmission service'') [125] be subject to a solar requirement to reflect solar heating in two ways, one based on solar heating derived from the sun's position and one based on up-to-date forecasts of forecastable cloud cover, subject to certain exceptions.

84. This proposal would apply to all transmission line ratings because it is our understanding that the solar requirement can be incorporated without installing sensors, enabling the benefit of additional transfer capability through more accurate accounting of solar heating with only minimal implementation costs. Further, this proposal would apply the solar requirement to near-term transmission service because the requirement effectively would subsume the daytime/nighttime solar heating requirement set forth in Order No. 881, which applies to near-term transmission service. The currently effective Attachment M of the *pro forma* OATT already provides for transmission providers to take a self-exception to the requirement to include solar heating in transmission line ratings for transmission lines for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on solar heating, and for transmission lines whose transfer capability is limited by a transmission

[116] *See* PPL Comments, Docket No. AD22–5, at 15 (filed Apr. 25, 2022).

[117] *See* AES Corporation and LineVision, Inc., *Lessons from First Deployment of Dynamic Line Ratings,* at 17 (Apr. 2024); DOE Comments, Docket No. AD22–5, attach. A at 57–58 (filed Apr. 25, 2022).

[118] Order No. 881, 177 FERC ¶ 61,179 at P 35.

[119] *Id.* P 39.

[120] The proposed reforms in this ANOPR apply only to thermal ratings. Therefore, unless otherwise noted, use of the term ''rating'' hereafter should be assumed to mean ''thermal rating.''

[121] *Id.* P 255.

[122] We note that, per Attachment M of the *pro forma* OATT, a transmission line rating would apply to both the conductor and any relevant transmission equipment, which includes but is not limited to circuit breakers, line traps, and transformers. *See pro forma* OATT, attach. M, Transmission Line Rating.

[123] NOI, 178 FERC ¶ 61,110 at P 17 (Question 17).

[124] Institute of Electrical and Electronics Engineers, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors 21–23, IEEE Std 738–2023 (2023) (IEEE 738); Conseil International des Grands Réseaux Électriques/International Council of Large Electric Systems (CIGRE), Guide for selection of weather parameters for bare overhead conductor ratings, Technical Brochure 299, Aug. 2006 (CIGRE TB 299).

[125] *See pro forma* OATT, attach. M, Near-Term Transmission Service.

system limit that is not dependent on solar heating.[126] The existing exception would also apply to the proposed requirement that transmission line ratings reflect solar heating based on the sun's position and forecastable cloud cover.

a. Reflecting Solar Heating Based on the Sun's Position

85. We preliminarily propose to require that all transmission line ratings used for near-term transmission service reflect solar heating based on the sun's position accounting for the relevant geographic location, date, and hour. Under this approach, transmission line ratings would reflect the potential for the sun to heat the transmission lines during each hour based on its position in the sky, assuming zero cloud cover. Stated another way, transmission providers will need to calculate, for each hour, the effect of the sun's position on its transmission line ratings. Transmission providers would have the discretion to calculate the effect of the sun's position on their transmission line ratings using more granular time increments. Because solar heating based on the sun's position starts at close to zero in the hours shortly after sunrise, rises throughout the morning hours to the midday peak, and then decreases through the afternoon to near zero again in the hours shortly before sunset, requiring all transmission line ratings used for near-term transmission service to reflect solar heating based on the sun's position may produce more accurate transmission line ratings than the daytime/nighttime assumptions required under Order No. 881.

86. As the Commission explained in Order No. 881,[127] clear-sky solar heating assumptions based on the sun's position can be computed with accuracy from formulas, such as those provided in standards like IEEE 738 or CIGRE TB 601.[128] Such calculations depend only on geographic location, date, and time and are therefore free of any forecast uncertainty. Likewise, such calculations do not require local sensors or weather data. The Commission considered whether AARs should incorporate such hourly clear-sky solar heating assumptions in Order No. 881 but elected at that time to instead require the simpler but less precise daytime/nighttime approach to solar heating. Under that approach, the AARs are required to reflect only the absence of solar heating during nighttime periods, where local sunrise/sunset times are updated at least monthly. The Commission found that, compared to the hourly clear-sky solar heating approach, the simpler daytime/nighttime approach ''balance[d] the benefits and burdens'' associated with the rule.[129]

87. However, upon considering the NOI comments, and based on subsequent outreach and further research, we preliminarily find that the benefits of more accurate transmission line ratings that reflect solar heating based on the sun's position are significant. This is particularly true during the hours right after sunrise and right before sunset—hours with relatively little solar heating. Because electric demand often peaks in the hours just before sunset, assuming midday solar heating during these hours may understate the amount of transfer capability available and increase the costs and challenges of reliably meeting peak demand. Additionally, regions with high levels of solar generation may benefit from the additional transmission capacity as load rises and solar generation declines, which further demonstrates that understating the amount of transfer capability available during these hours may increase the costs and challenges of maintaining reliability.

88. The record in the Order No. 881 proceeding indicates that considering solar heating based on the sun's position can affect a transmission line's rating by as much as 5% to 11%.[130] Also, joint research by Commission staff and NOAA staff modeled the effect of the absence of solar heating on the rating of a typical aluminum conductor steel reinforced (ACSR) cable and found that transmission line ratings could increase by about 12% in the hours immediately after sunrise and before sunset.[131] While this range of percentages represents expected transmission line rating increases between assuming full midday sun and assuming no sun whatsoever, they nonetheless demonstrate that transmission line ratings would likely significantly increase in the early morning and late afternoon hours, and moderately increase in most other daytime hours, relative to assuming full midday sun conditions during all daylight hours. For example, Commission and NOAA staff's modeling found that considering hourly clear-sky solar heating increased transmission line ratings (relative to the daytime/nighttime ratings approach) in each of the four hours immediately after sunrise and before sunset by 4% to 12%.[132]

89. We seek comment on our preliminary proposal to require that all transmission line ratings used for near-term transmission service reflect solar heating based on the sun's position for the relevant geographic location, date, and hour under a clear sky. We also seek comment on the costs, non-financial burdens, and financial and non-financial benefits of this requirement.

90. As noted in section III. The Potential Need for Reform above, we preliminarily find that transmission line ratings used for near-term transmission service that do not reflect solar heating based on the sun's position may result in unjust and unreasonable wholesale rates. In addition to the requests for comments on specific aspects of this preliminary proposal, we seek comment on whether reflecting solar heating based on the sun's position in transmission line ratings used for near-term transmission service would result in more accurate transmission line ratings and would, in turn, better reflect system transfer capability. We also seek comment on whether the greater accuracy of transmission line ratings would result in cost savings and just and reasonable wholesale rates. Further, given that the sun's position is forecastable without uncertainty, we seek comment on whether transmission providers should reflect solar heating based on the sun's position for transmission service longer than 10 days forward.

[126] *See id.,* attach. M, Obligations of the Transmission Provider; *see also* Order No. 881, 177 FERC ¶ 61,179 at P 227.

[127] Order No. 881, 177 FERC ¶ 61,179 at P 150.

[128] Institute of Electrical and Electronics Engineers, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors 21–23, IEEE Std 738–2023 (2023) (IEEE 738); Conseil International des Grands Réseaux Électriques/International Council of Large Electric Systems (CIGRE), Guide for Thermal Rating Calculations of Overhead Lines, Technical Brochure 601, Dec. 2014.

[129] Order No. 881, 177 FERC ¶ 61,179 at P 150.

[130] Potomac Economic Comments, Docket No. RM20–16, at 15 (filed Mar. 23, 2021) (''We estimate that the average size of [setting solar irradiance to zero] for nighttime ratings to be an 11 percent increase''); PG&E Comments, Docket No. RM20–16, at 11 (filed Mar. 22, 2021) (''PJM's research shows that at least 14% of their line ratings are increased by 10% by considering solar irradiance''); Entergy Comments, Docket No. RM20–16, at 8 (filed Mar. 22, 2021) (''The shade of the night provides an additional 5% to the ratings of the lines'').

[131] Lisa Sosna, et al., *Demonstration of Potential Data/Calculation Workflows Under FERC Order 881's Ambient-Adjusted Rating (AAR) Requirements,* joint FERC/NOAA staff presentation at FERC's 2022 Software Conference at slide 29 (June 23, 2022), *https://www.ferc.gov/media/demonstration-potential-datacalculation-workflows-under-ferc-order-no-881s-ambient-adjusted.* Actual increases could vary from the modeled increase, depending on conductor surface conditions and other factors.

[132] *Id.*

b. Reflecting Solar Heating Based on Forecastable Cloud Cover

91. We preliminarily propose to require that all transmission line ratings used for near-term transmission service reflect solar heating based on up-to-date forecasts of forecastable cloud cover. Transmission providers will need to reflect, for each hour, the effect of forecastable cloud cover on its transmission line ratings. Transmission providers would have the discretion to calculate the effect of the sun's position on their transmission line ratings using more granular time increments. This proposal does not imply that the cloud cover must be forecastable for the entire 10 days, but rather that transmission providers should reflect forecastable cloud cover in their up-to-date forecasts as that information becomes available.[133] Based on outreach and research, we understand that certain overcast periods can be forecast accurately in certain conditions. For example, some portions of the continental United States regularly see overcast conditions for weeks at a time. During such periods, solar heating can be significantly reduced, significantly increasing transmission transfer capability.

92. We preliminarily propose to define forecastable cloud cover as cloud cover that is reasonably determined, in accordance with good utility practice, to be forecastable to a sufficient level of confidence to be reflected in transmission line ratings. We clarify that we are not proposing to require that transmission providers seek to forecast individual clouds, or even most cloud formations. We seek comment on this definition of forecastable cloud cover and the level of confidence that is necessary to incorporate and benefit from a cloud cover forecast.

93. We also seek comment on whether sensors are needed to accurately forecast cloud cover. If commenters believe local sensors are required to accurately forecast cloud cover events, we seek comment on how such sensors improve such forecasts.

94. We note that some cloud cover events may be more easily forecast forward than other cloud cover events. Some overcast conditions will not be forecastable at all. For many or most weather systems that produce forecastable cloud cover conditions, such conditions may be forecastable only for a short time ahead of a given operating hour, rather than for the full 10 days forward. For other very large weather systems, or for periods of seasonal overcast conditions in some parts of the country, such conditions may be forecastable for longer periods.

95. Therefore, we propose to limit the proposed requirement to reflect up-to-date forecasts of *forecastable* cloud cover because, if a cloud cover event is not ''forecastable,'' then we believe it would not be practical to require that it be reflected. However, if a cloud cover event becomes ''forecastable'' during the relevant timeframe, it must be reflected in the up-to-date forecasts under the proposed requirement. Specifically, under the proposed requirement, forecastable cloud cover data must be incorporated into ratings calculations as close to real time as reasonably possible (*i.e.,* as close to the time that a relevant forecast becomes available) given the timelines needed to obtain forecast data and perform the calculation, as well as any other steps needed for validation, communication, or implementation of the transmission line rating.[134] We seek comment on this proposal to require that transmission providers incorporate up-to-date forecasts of forecastable cloud cover into all transmission line ratings used for near-term transmission service. We also seek comment on whether the requirement to incorporate up-to-date forecasts of forecastable cloud cover should apply to transmission services other than near-term transmission service and whether all transmission service should be subject to this requirement, not just near-term transmission service.

96. We seek comment on the costs, non-financial burdens, and financial and non-financial benefits of reflecting solar heating through the use of up-to-date forecasts of forecastable cloud cover in transmission line ratings used for near-term transmission service, and the extent to which this practice would increase the accuracy of the resulting transmission line rating. Further, we seek comment on whether transmission providers should reflect up-to-date forecasts of forecastable cloud cover in transmission line ratings used for transmission service up to 10 days forward or whether these forecasts should be reflected only in the transmission line ratings used for a shorter time frame, such as 36 or 48 hours forward. If parties believe sensors are required to accurately forecast cloud cover, we seek comment on whether cloud cover should alternatively be reflected only in transmission line ratings for transmission lines that exceed a congestion threshold, and what that threshold should be. We seek comment on whether, alternatively, up-to-date forecasts of forecastable cloud cover should be reflected only in the ratings of the more limited set of transmission lines we propose would be subject to a wind requirement (described below).

3. Potential Wind Requirement

97. We preliminarily propose to additionally require certain transmission lines to reflect up-to-date forecasts of wind conditions, including wind speed and direction, in their transmission line ratings for use in 48-hour transmission service, as defined below in section IV.A.3.a.i.a 48-Hour Transmission Service. We preliminarily propose that this wind requirement would be implemented only on transmission lines[135] exceeding thresholds for wind speed[136] and congestion.[137] Other transmission lines would not be subject to the wind requirement but would still be subject to the solar requirement discussed above.

98. We preliminarily propose that, for each transmission line that is subject to the wind requirement, individual transmission providers apply good utility practice to determine which specific electric system equipment associated with that line—beyond the conductor—is affected by wind conditions and thus also would be subject to the wind requirement. This approach is similar to that taken by the Commission in Order No. 881 with respect to AARs.[138] We seek comment on whether the wind requirement should explicitly apply only to the conductor portion of a transmission line, and if so why.

a. Components of a Wind Requirement

99. We preliminarily propose to require transmission providers to reflect up-to-date forecasts of wind speed and wind direction in transmission line ratings on lines subject to the wind requirement. We propose to apply this wind requirement to only transmission lines exceeding thresholds for wind speed and congestion. A potential final rule imposing such a wind requirement would modify *pro forma* OATT

[133] *See infra* P 95.

[134] *See* Order No. 881, 177 FERC ¶ 61,179 at P 143.

[135] *Id.* P 44.

[136] This threshold is described below in section IV.A.3.b.ii Wind Speed Threshold.

[137] This threshold is described below in section IV.A.3.b.iii Congestion Threshold.

[138] This proposal is consistent with the definition of Transmission Line Rating in Attachment M of the *pro forma* OATT, which includes ''considering the technical limitations on conductors and relevant transmission equipment . . . [which] may include, but is not limited to, circuit breakers, line traps, and transformers.'' *See pro forma* OATT, attach. M, Definitions; *see also* Order No. 881, 177 FERC ¶ 61,179 at PP 44–45.

Attachment M and specify details of the wind requirement, including the time horizon, wind forecasting requirements, sensor requirements, exceptions, and transparency of relevant data. Below we provide additional detail and seek comment on these elements of a wind requirement.

100. As noted in section III. The Potential Need for Reform above, we preliminarily find that certain transmission line ratings that do not reflect up-to-date forecasts of wind speed and direction may result in unjust and unreasonable wholesale rates.

i. Time Horizon and Forecasting Requirement

101. For transmission lines subject to a wind requirement, we preliminarily propose to require transmission providers to use transmission line ratings that account for wind speed and direction as the basis for evaluating requests for transmission services that will end within 48 hours of the transmission service request (48-hour transmission service). For those transmission lines, this approach would require transmission providers to use transmission line ratings that reflect up-to-date forecasts of wind speed and direction to evaluate requests for hourly and daily point-to-point transmission services under the *pro forma* OATT that fall within the 48-hour time horizon. All longer-term (weekly, monthly, yearly) point-to-point services would not be affected by this requirement. For those transmission lines, transmission providers would also use transmission line ratings that incorporate the proposed wind requirement in determining whether to curtail, interrupt, or redispatch transmission service on transmission lines subject to a wind requirement, if such curtailment or redispatch is necessary because of issues related to flow limits on transmission lines and anticipated to occur within the next 48 hours of such determination.

102. In the NOI, the Commission asked about the timeframes (and corresponding types of transmission service) for which DLRs should be used. In response, some commenters argue that DLRs should be used for a variety of transmission services, including hourly, daily, and weekly services.[139] Other commenters argue that DLRs should be used only in real-time operations for decisions regarding curtailment, interruption, and redispatch.[140]

103. Accordingly, we seek comment on the appropriateness of the proposed 48-hour time horizon. We note that current DLR implementations reflect the use of DLRs across timeframes sufficient to include DLRs in the real-time and day-ahead markets of RTOs/ISOs. For example, PPL uses DLRs in the PJM real-time and day-ahead energy markets.[141] We also understand that DLR vendors offer services that calculate DLRs as far as 10 days into the future.[142] However, given that the forecast uncertainty for wind speed and direction that would underlie a wind requirement likely increases the longer the time period, we preliminarily believe that the time horizon for a wind requirement should be shorter than the 10-day horizon for the existing AAR requirement.

104. The appropriate time horizon for which transmission service evaluations should incorporate a wind requirement depends on whether the accuracy benefit of incorporating wind forecasts exceeds the burden of calculating and managing the ratings for such forward hours. At longer time horizons, forecast uncertainty increases, perhaps resulting in the need for larger forecast margins to ensure the necessary level of confidence in the forecasts.[143] On the other hand, limiting the wind requirement to a short time horizon would forego the benefits of more accurate transmission line ratings because those benefits would only accrue for a smaller number of hours and a more limited set of transmission services.

105. Because the bulk of the effort of calculating and archiving of transmission line ratings on transmission lines subject to the wind requirement is in the setup of the automated systems, we anticipate that the data burdens of this option would not vary significantly depending on the time horizons.[144] Nevertheless, we seek comment on whether applying a wind requirement to transmission line ratings over longer time horizons would result in a greater data burden as compared to a wind requirements for shorter-time horizons.

106. Considering all of these factors, we preliminarily find that a 48-hour time horizon provides a reasonable balance between the benefits and burdens associated with a wind requirement and may therefore be appropriate for a potential wind requirement. Such a timeframe seems to strike the right balance of creating significant benefits by covering important transmission service transactions, such as those in the RTO/ISO day-ahead markets, while reflecting that implementing a wind requirement for longer timeframes may not supply sufficient value to justify the burden. We seek comment on whether the 48-hour time horizon is the appropriate timeframe or whether the Commission should consider requiring a longer time horizon (*e.g.,* a week, 10 days, monthly). We seek comment on the accuracy of the forecasting of wind speed and wind direction in these time horizons (including the 48-hour time horizon), and any potential benefits and burdens that may result from a longer time horizon. We also seek comment on the ability of DLR vendors to calculate DLRs in these time horizons, and at what level of confidence.

ii. Sensor Requirements

107. We preliminarily propose that transmission providers, for their transmission lines subject to the wind requirement, install sensors that measure wind speed and direction as

[139] Clean Energy Parties Comments, Docket No. AD22–5, at 15 (filed Apr. 25, 2022) (hourly or sub-hourly); LADWP Comments, Docket No. AD22–5, at 7 (filed Apr. 25, 2022) (daily or hourly); WATT/CEE Comments, Docket No. AD22–5, at 16 (filed Apr. 25, 2022) (near-term transmission service as defined in Order 881).

[140] APS Comments, Docket No. AD22–5, at 12 (filed Apr. 25, 2022); NYTOs Comments, Docket No. AD22–5, at 16 (filed Apr. 25, 2022); EEI Comments, Docket No. AD22–5, at 5 (filed Apr. 25, 2022); Eversource Comments, Docket No. AD22–5, at 4–5 (filed Apr. 25, 2022); NYISO Comments, Docket No. AD22–5, at 6 (filed Apr. 25, 2022); Entergy Comments, Docket No. AD22–5, at 5 (filed Apr. 25, 2022); MISO Comments, Docket No. AD22–5, at 32 (filed Apr. 25, 2022).

[141] *See* PPL Comments, Docket No. AD22–5, at 14 (filed Apr. 25, 2022).

[142] *See, e.g.,* LineVision, *Technology: Software,* (stating that LineVision's LineRate DLR product provides ''[f]orecasted DLR, hourly, up to 240 hours (10 days) out''), *www.linevisioninc.com/technology#software.*

[143] In Order No. 881, the Commission required transmission providers to use AARs as the basis for evaluating ''near-term'' transmission service requests, defined as transmission service that ends not more than 10 days after the transmission service request date, because the Commission determined that forecasts of ambient air temperature were sufficiently accurate up to 10 days into the future, and that transmission line ratings based on such 10-day-ahead forecasts would provide sufficient benefits. Order No. 881, 177 FERC ¶ 61,179 at PP 120–121. For transmission service that is beyond 10 days forward, however, the Commission found that seasonal line ratings are the appropriate transmission line ratings because ambient air temperature forecasts for such future periods have more uncertainty than near-term forecasts, and thus tend to converge to the longer-term ambient air temperature forecasts used in seasonal line ratings. *Id.* P 200; *cf. id.* P 105 (discussing the justification for the 10-day threshold for the use of AARs).

[144] For example, Clean Energy Parties and WATT/CEE state that system integration is a one-time engineering effort before it becomes plug-and-play, and that resources for subsequent installation on additional transmission lines will be limited to the time needed to determine the location of, and to install, DLR sensors. Clean Energy Parties Comments, Docket No. AD22–5, at 20 (filed Apr. 25, 2022); WATT/CEE Comments, Docket No. AD22–5, at 19–20 (filed Apr. 25, 2022).

determined to be necessary for forecast training or to otherwise ensure adequate information about local weather conditions.

108. We seek comment on whether the Commission should require a transmission provider to determine what sensors, if any, need to be installed for forecast validation and forecast training in order to ensure that forecasts of wind speed and direction are sufficiently accurate. We propose that, in doing so, transmission providers should consider a non-exhaustive list of factors including: average ambient wind speed at the relevant altitude(s), distribution of wind direction at the relevant altitude(s), length and configuration of conductors, local topography, local vegetation, and position of weather stations. We seek comment on what other factors transmission providers should be required to consider when determining what sensors, if any, need to be installed.

109. Further, if commenters believe that detailed sensor configuration requirements are not necessary for transmission lines subject to a wind requirement, we seek comment on why that approach is preferable and how such requirements should be constructed.

110. We also seek comment on whether the Commission should mandate sensors at all. We understand that some vendors are offering approaches to DLRs that do not use sensors.[145] For example, a wind requirement could simply require that transmission line ratings reflect up-to-date forecasts of wind speed and wind direction. Under such an approach, the wind requirement would be defined in terms of the wind conditions that must be reflected in the transmission line ratings, rather than what technical equipment transmission providers must use to produce wind forecasts. This approach is similar to the requirements adopted in Order No. 881 for AARs to reflect up-to-date forecasts of ambient air temperature. We seek comment on whether the technology and capability to determine accurate forecasts of wind speed and wind direction currently exists, or will exist in the near future, such that transmission providers can use a sensor-less DLR to accurately and safely determine their transmission line ratings. We seek comment on whether there are benefits to a sensor-less approach, beyond cost savings, as compared to a sensor-based approach. We also seek comment on the costs of sensor-less approaches, including any comparison to the costs of measuring wind speed and direction using sensors. We seek comment on whether there any certain scenarios (*i.e.,* line configurations, types of lines) where a sensor-based approach may be preferable to sensor-less approach.

111. We also seek comment on whether, if a wind requirement generally requires the use of sensors, the Commission should give transmission providers the discretion to determine that *no sensors* are required in certain instances. Specifically, we seek comment on what types of factors transmission providers should consider when identifying such instances and whether such factors should be reflected in any ultimate Commission directive. We also seek comment on whether an explicit provision would be necessary to give transmission providers such latitude, or if requiring the use of sensors ''as determined to be necessary'' would be sufficient to provide such latitude. Additionally, to the extent that the Commission does not require the use of sensors, we seek comment on how this would affect other proposals in this rule (*i.e.,* the congestion threshold, timing considerations, etc.).

112. We seek comment on the applicability of NERC Facility Ratings Reliability Standard FAC–008–5 and NERC Transmission Relay Loadability Reliability Standard PRC–023–4 to the wind requirement and whether any changes would need to be made to these or other NERC Reliability Standards to accommodate a potential wind requirement.

113. Further, we seek comment on the type and costs of needed communications equipment, computer hardware, and computer software required to integrate sensors and associated data into the transmission provider's EMS. We seek comment on whether changes are needed to the NERC Critical Infrastructure Protection (CIP) Reliability Standards or other industry practices to ensure the physical security and cybersecurity of the sensors, data communications, transmission line rating and forecasting systems, and EMS improvements used to implement a wind requirement. In particular, we seek comment on whether additional controls are necessary to validate that sensors are operating correctly and that any changes in ratings based on sensor data are appropriate for that particular transmission line, taking all relevant considerations into account. Further, we seek comment on whether entities should have a backup or other means to acquire the data or establish transmission line ratings if the DLR systems are compromised or not functioning properly.

b. Proposed Criteria To Identify Transmission Lines Subject to a Wind Requirement

114. As discussed in section II.C.3. Current Use of DLRs, research and select experience suggest that incorporating a wind requirement could provide significant benefits through more accurate line ratings. However, the record gathered through the NOI suggests that implementing the wind requirement would produce significant benefits only under certain circumstances.[146] We preliminarily agree with several commenters to the NOI that candidate transmission lines for a wind requirement should be identified through Commission-determined criteria[147] instead of relying on cost-benefit analyses. Thus, we preliminarily propose to apply the wind requirement only to transmission lines that meet certain wind speed and congestion thresholds and to limit the number of lines subject to the wind requirement in any one year.

i. Number of Transmission Lines Subject to the Wind Requirement Annually

115. We recognize that implementing the wind requirement may present some challenges (particularly during the initial implementation), such as siting

[145] *See, e.g.,* SPLIGHT Comments, Docket No. AD22–5, at 4 (filed Mar. 21, 2024) (referencing ''software-only solutions [that can enable] DLR utilization across entire grid systems''); Renan Giovanini, *GE Digital Grid Software: Orchestrate the Clean Energy Grid,* General Electric presentation at FERC's Software Conference referencing sensor-free digital twin DLR at slide 6 (June 27, 2023), *https://www.ferc.gov/media/renan-giovanini-general-electric-edinburgh-uk.*

[146] *See, e.g.,* APPA/LPPC Comments, Docket No. AD22–5, at 8–10,12 (filed Apr. 25, 2022); APS Comments, Docket No. AD22–5, at 4 (filed Apr. 25, 2022); DOE Comments, Docket No. AD22–5, Attachment A at ii (filed Apr. 25, 2022) (addressing the impacts of grid-enhancing technologies generally); AEP Comments, Docket No. AD22–5, at 10 (filed Apr. 25, 2022); EGM Comments, Docket No. AD22–5, at 8 (filed Apr. 22, 2022); LADWP Comments, Docket No. AD22–5, at 3 (filed Apr. 25, 2022); MISO Comments, Docket No. AD22–5, at 17–18 (filed Apr. 25, 2022); NRECA Comments, Docket No. AD22–5, at 14 (filed Apr. 25, 2022); NYTOs Comments, Docket No. AD22–5, at 11 (filed Apr. 25, 2022); PPL Comments, Docket No. AD22–5, at 9 (filed Apr. 25, 2022); PJM Comments, Docket No. AD22–5, at 2–3 (filed May 9, 2022); Southern Company Comments, Docket No. AD22–5, at 2–3 (filed Apr. 25, 2022); Tri-State Comments, Docket No. AD22–5, at 3 (Apr. 25, 2022); WATT/CEE Comments, Docket No. AD22–5, at 10 (filed Apr. 25, 2022).

[147] *See, e.g.,* BPA Comments, Docket No. AD22–5, at 10–11 (filed Apr. 25, 2022); CAISO Comments, Docket No. AD22–5, at 3 (filed Apr. 25, 2022); Certain TDUs Comments, Docket No. AD22–5, at 7 (filed Apr. 25, 2022); EGM Comments, Docket No. AD22–5, at 5–6 (filed Apr. 22, 2022); PJM Comments, Docket No. AD22–5, at 5–9 (filed May 9, 2022).

and installing sensors, particularly in remote locations, integrating DLRs with existing operations, and ensuring secure data communication and cybersecurity.[148] Thus, in order to ensure that any wind requirement is implemented in a reliable and effective manner, we preliminarily propose to limit the number of transmission lines on which a transmission provider must implement the wind requirement in any given year. We preliminarily propose that such a limit account for the fact that larger transmission providers tend to have more resources to implement the wind requirement than smaller transmission providers. With that in mind, we preliminarily propose to require that, for transmission providers with transmission lines subject to the wind requirement, transmission providers apply the wind requirement to, at least, a number of transmission lines equal to 0.25% (or 1 in 400) of that transmission provider's Commission-jurisdictional transmission lines, rounded up to the next whole number.[149] Alternatively, we seek comment on whether the minimum number of lines that a transmission provider must apply the wind requirement in an implementation cycle should be based on a percentage of lines that meet the wind and congestion thresholds rather than, as proposed above, a percentage of all lines. We anticipate that, after initial implementation, transmission providers will have the experience necessary to apply the wind requirements on more lines per year. We are also concerned that applying the wind requirements to only 0.25% of the transmission provider's total transmission lines per year will be too slow of a pace. Accordingly, we seek comment on the best approach to increasing the requirement. We seek comment on whether the Commission should increase the percentage of lines to which transmission providers must apply the wind requirements, for any transmission lines that meet the thresholds (*i.e.,* 0.25% of lines in years 1 and 2 after implementation, 0.5% of lines in years 3 through 5, and 1% of lines in ensuing years)? Alternatively, we seek comment on whether the Commission should select a time upon which transmission providers must incorporate the wind requirement to all lines that meet the wind speed and congestion thresholds (*i.e.,* at least 0.25% per year for the first five years after implementation, but all lines that meet the thresholds must apply the wind requirement by year six). Further, as discussed below, transmission providers would be required to implement the wind requirement only on transmission lines that meet both a wind speed threshold and a congestion threshold.

116. For purposes of counting a transmission provider's total number of transmission lines and determining the number of transmission lines that would be subject to a wind requirement in a given year, we preliminarily propose to define a single transmission line as the transmission conductor that runs between its substation or switchyard start and end points (*e.g.,* dead-end structures). Other transmission facilities and equipment, such as circuit breakers, line traps, and transformers, would not count toward the transmission provider's total number of transmission lines. We seek comment on whether we should instead count the total number of transmission facilities based on the number of pieces of individually rated Commission-jurisdictional transmission equipment, as identified by the transmission provider and included in the database of transmission line ratings.[150] In other words, the number of transmission lines would be approximated based on the size of the transmission line ratings database developed for Order No. 881 compliance for a given transmission provider.

117. We seek comment on the preliminary proposal to require that transmission providers implement the wind requirement, for any transmission lines that meet the thresholds, on at least 0.25% of their transmission lines in each annual cycle. We seek comment on approximately how many jurisdictional transmission lines 0.25% represents, and how many transmission lines the average transmission provider operates. We seek comment on whether the Commission should adopt a different initial annual percentage. Alternatively, should the Commission consider a requirement for transmission providers, after a few years of DLR experience, to review their pace of implementation? We also seek comment on whether the Commission would need to adjust this approach if it determines that sensors are not needed for the wind requirement. We seek comment on whether we should consider alternative approaches to limiting a transmission provider's annual implementation requirements, such as limits based on the peak load on the transmission provider's transmission system or other appropriate criteria or metrics. We also seek comment on whether and how considerations such as staffing, supply chains, vendor availability, and limited experience with sensor technology for many transmission providers should factor into any such annual limitation on implementation of the wind requirement. We also seek comment on the appropriateness of establishing a limit on the number of transmission lines subject to a wind requirement.

ii. Wind Speed Threshold

118. We preliminarily propose to apply a wind requirement only to transmission lines where at least 75% of the length of the transmission line is located in areas with historical average wind speeds of at least 3 meters per second (m/s) (6.7 miles per hour) measured at 10 meters above the ground, roughly the height of most transmission lines. While we believe that requiring application of a wind speed threshold over the entire length of the line could be too limiting, ultimately excluding transmission lines where application of the wind requirement would yield net benefits, we also believe that including too long of a non-windy portions of the line will cause those segments to bind more often and limit the additional capacity from the wind requirement. Thus, we have proposed 75% of the line length located in areas with wind as the threshold. In NOI comments, WATT/CEE suggests using a similar wind speed threshold of 4 m/s.[151] Based on outreach and further research, however, we preliminarily propose a wind speed threshold of 3 m/s, on average.[152]

119. We note that historical wind speed data are published in graphical and raster format for the continental United States by the National Renewable Energy Laboratory

[148] *See, e.g.,* Order No. 881, 177 FERC ¶ 61,179 at P 254; AEP Comments, Docket No. AD22–5, at 5 (filed Apr. 25, 2022); APPA/LPPC Comments, Docket No. AD22–5, at 3–7 (filed Apr. 25, 2022), BPA Comments, Docket No. AD22–5, at 7–8 (filed Apr. 25, 2022).

[149] For example, for a transmission provider with 1,130 transmission lines in a given year, 0.25% of its lines would be (0.0025) * (1,130) = 2.825 lines. As such, that transmission provider would not be required to implement the wind requirement on more than 3 of its transmission lines in that year, even if more than 3 of its transmission lines meet both a wind speed threshold and a congestion threshold. Transmission providers could, of course, voluntarily implement the wind requirement on additional transmission lines in any given year, but under this preliminary proposal they would not be *required* to do so.

[150] *See* Order No. 881, 177 FERC ¶ 61,179 at PP 330, 336–340.

[151] WATT/CEE Comments, Docket No. AD22–5, at 7 (filed Apr. 25, 2022).

[152] *See, e.g.,* Jake Gentle, *et al., Forecasting for Dynamic Line Ratings,* Idaho National Laboratory presentation at FERC DLR Workshop at slide 13 (Sept. 10, 2019), *https://www.ferc.gov/sites/default/files/2020-09/Gentle-INL.pdf.*

(NREL),[153] and we preliminarily propose that transmission providers use this NREL data source as the basis for implementing the wind speed threshold.

120. We seek comment on the proposed wind speed threshold of 3 m/s, on average, including whether another wind speed would be a more appropriate threshold. We also seek comment on the proposal to apply the wind requirement only on transmission lines where at least 75% of the transmission line length is located in areas with average wind speeds at or above the threshold, including whether another approach to applying the wind speed threshold would be more appropriate for transmission lines located in areas both above and below the threshold. Further, we seek comment on the preliminary proposal to require that transmission providers use NREL data for historical wind speeds at 10 meters above the ground for purposes of evaluating whether a transmission line is above or below the wind speed threshold, and whether an alternative data source would be more appropriate.

121. Finally, we acknowledge that wind direction is another important factor. Wind moving perpendicular to a transmission line cools the line much more effectively than wind moving parallel to the line. However, we preliminarily find that establishing a threshold that includes an average historical wind direction would be much more burdensome to calculate because it would require that the transmission provider determine the wind direction relative to the position of each transmission line. We seek comment on whether wind direction should also be considered when identifying transmission lines subject to a wind requirement, and if so, how such consideration should be structured and what data sources should be used.

iii. Congestion Threshold

122. We preliminarily propose to use congestion caused by a transmission line rating as a second threshold for identifying the transmission lines that would be subject to a wind requirement. Below, we discuss how to calculate a congestion value for each transmission line in RTO/ISO regions and, separately, in non-RTO/ISO regions, and how to establish a threshold to identify congested transmission lines in each region. Transmission lines that have no congestion or congestion levels below the proposed threshold would not be subject to any wind requirement even if they meet the wind speed threshold because, absent sufficient levels of congestion, we do not expect the benefits resulting from a more accurate transmission line rating to exceed the costs.

(a) RTO/ISO Regions

(1) Congestion Costs

123. We seek comment on the appropriate congestion cost threshold to use in the RTO/ISO regions. In response to the NOI, some commenters propose to directly use congestion costs to indicate which transmission lines should be subject to a DLR requirement in RTO/ISO regions, and even propose specific annual congestion cost thresholds. At the low end of the range of suggestions, WATT/CEE and Clean Energy Parties recommend requiring DLRs on any transmission line with congestion costs of at least $500,000 over the past year.[154] Citing the Midcontinent Independent System Operator, Inc. transmission owners' cost estimate of $100,000–$200,000 for DLR implementation per transmission line, WATT/CEE argues that this threshold would allow customers to break even on DLR installations within approximately two years.[155] At the high end of the range of suggestions, PJM recommends requiring DLRs on any transmission line with annual congestion costs of at least $2 million.[156]

124. At this point, the Commission has a limited record on the best approach for calculating congestion costs in RTOs/ISOs for purposes of defining a congestion threshold for a wind requirement. As discussed above in section II.D.2. Existing Data Reporting on Congestion, or Proxies of Congestion, RTOs/ISOs regularly compute and publish various congestion metrics, but these metrics generally relate to marginal congestion costs rather than the total congestion costs caused by a transmission constraint. Thus, we seek comment on what approaches to calculating or estimating congestion costs caused by a transmission constraint would be most appropriate to use as part of a congestion threshold for a potential wind requirement in RTOs/ISOs. Relatedly, we seek comment on whether congestion costs caused by a transmission constraint should be determined based on the real-time markets, day-ahead markets, or a combination of the two.

125. Further, we seek comment on what congestion threshold the Commission should establish in RTO/ISO regions for a potential wind requirement, recognizing that the appropriate level of the congestion threshold could vary depending on the method used to calculate congestion costs. For example, were the Commission to use an annual congestion method as assumed by some commenters in response to the NOI, we seek comment on the values proposed and approximately how many transmission lines would meet the various thresholds. We note that WATT/CEE proposed $500,000 per year,[157] and PJM proposed $2 million per year.[158] Alternatively, as proposed by several commenters to the NOI, a congestion threshold could be set so that only transmission lines that have an average annual congestion cost of $1 million or more during the data collection period, discussed below in section IV.B.3. Phased-In Implementation Timeframe for the Wind Requirement, would be subject to the wind requirement. We also seek comment on whether the annual threshold should be annually adjusted for inflation; if so, how; and whether that adjustment should vary based on the method used for calculating congestion costs.

126. We seek comment on how RTOs/ISOs should measure congestion costs at interties and whether the same congestion threshold should be used for both intertie and internal congestion costs measurements. We also seek comment on how entities in non-RTO/ISO market constructs, such as the Western Energy Imbalance Market, should measure congestion costs at their interties.

127. Finally, we seek comment on whether a different congestion threshold would be appropriate if it is determined that the wind requirement does not require sensors. If the wind requirement can be met without sensors, this may lower the costs necessary to comply with the requirement. The lower costs may in turn provide more net benefits at lower levels of congestion.

(b) Non-RTO/ISO Regions

(1) Limiting Element Rate

(i) Overview

128. In non-RTO/ISO regions, congestion costs are not reflected separately as a component in market

[153] NREL, *Geospatial Data Science: Wind Resource Maps and Data, https://www.nrel.gov/gis/wind-resource-maps.html.*

[154] Clean Energy Parties Comments, Docket No. AD22–5, at 8 (filed Apr. 25, 2022); WATT/CEE Comments, Docket No. AD22–5, at 6 (filed Apr. 25, 2022).

[155] WATT/CEE Comments, Docket No. AD22–5, at 6 (filed Apr. 25, 2022).

[156] PJM Comments, Docket No. AD22–5, at 9 (filed May 9, 2022).

[157] WATT/CEE Comments, Docket No. AD22–5, at 6 (filed Apr. 25, 2022).

[158] PJM Comments, Docket No. AD22–5, at 9 (filed May 9, 2022).

prices and are not typically published in reports. Based on available information (at least some of which is currently publicly reported in some form,[159] and some of which is available to transmission providers but not currently published), we preliminarily propose a new metric to serve as a proxy for congestion in these regions—a Limiting Element Rate (LER). The LER metric would express, as an average rate (in MWh/year), the adverse impacts on transmission service due to a transmission line rating serving as a limiting element. Below we discuss how a transmission provider would calculate the LER, including data to be collected for certain ''triggering events,'' what LER metric threshold would be appropriate to identify transmission lines that are sufficiently congested to be subject to a wind requirement, and whether there are alternatives measures of congestion to identify transmission lines that should be subject to a wind requirement.

(ii) Triggering Events

129. We preliminarily propose to require that transmission providers record information for five types of triggering events where firm transmission service is denied or disrupted because of a transmission line's line rating. This information would provide the basis to identify transmission lines that are subject to a wind requirement.

130. In particular, the five events where firm transmission service is denied or disrupted because of a transmission line's line rating are: (1) denials of requested firm point-to-point transmission service; (2) denials of requests to designate network resources or load; (3) curtailment of firm point-to-point transmission service under section 13.6 of the *pro forma* OATT; (4) curtailment of network integration transmission service or secondary network integration transmission service under section 33 of the *pro forma* OATT; and/or (5) redispatch of network integration transmission service or secondary network integration transmission service under sections 30.5 and 33 of the *pro forma* OATT.

131. While we preliminarily propose to reflect each hour of a firm point-to-point transmission service reservation that is denied in the calculation of LER, in practice transmission customers do not typically schedule transmission service for every hour of their long-term reservations. For example, a transmission customer requesting a 100 MW reservation for annual transmission service may intend to use that service only during select hours totaling only six months of that year. Recognizing that fact, we seek comment on whether, for denials of requested firm point-to-point transmission service, the number of hours reflected in the LER calculations should reflect a discount from the number of hours reflected in the actual request. If so, we seek comment on what such discount factor(s) should be, and whether a specific discount factor should apply to all such denied firm point-to-point services, or if such a discount factor should vary by service type (daily, weekly, monthly, or yearly) to reflect how different service types might be scheduled at different rates.

132. We seek comment on whether it would be appropriate to include a sixth triggering event as a proxy for congestion in the LER. This event would account for times when ATC in the operating hour[160] is less than or equal to 25% of TTC.[161] Such ''low ATC events'' would be limited to events on paths that meet the definition of a ''posted path'' under § 37.6(b)(1)(i) of the Commission's regulations. Accounting for low ATC events would be intended to capture instances when such low ATC could dissuade potential transmission customers from making a transmission service request in the first place. We seek comment on whether, and to what extent, a transmission line's low operating-hour ATC indicates congestion in any given hour, such that it should reasonably be factored in as a proxy for congestion that may trigger the wind requirement. We also seek comment on other triggering events that the Commission should consider.

(iii) Data To Be Collected and Reported

133. For any triggering event, we preliminarily propose to require the transmission provider to record the: (1) date/time of the record being added to its database of transmission line ratings;[162] (2) dates and times of the start and end of the event;[163] (3) event type; (4) specification of the transmission line with a transmission line rating that was the limiting element causing the event; and (5) MWh of transmission service (or potential transmission service) that was impacted by the event.

134. The details of how the transmission provider would determine the impacted MWh vary by event type. For instances of denied firm point-to-point service, the transmission provider would determine the impacted MWh by multiplying the MW of the service requested by the duration of the request in hours.[164] If, instead of a complete denial of requested point-to-point service, a lower level of interim service is granted, then the MW value used in such a calculation would reflect only the portion of the original requested service deferred or not granted.[165] For instances of curtailed or redispatched point-to-point or network transmission service, the transmission provider would determine the impacted MWh by multiplying the MW curtailed or redispatched by the duration of the event in hours.[166] If, in such an instance, the MW curtailed or redispatched varies during the duration of the curtailment or redispatch, then the transmission provider may use an average MW value, or record the different hours or periods as different events. We preliminarily propose that transmission providers be required to reflect in such determinations any curtailments made as part of conditional firm transmission service provided under section 15.4 of the *pro forma* OATT. Finally, for instances of denied requests to designate new network resources or load without an end date, we preliminarily propose to reflect that such designations are generally long-term events by considering such denied requests to have a duration of 180 days (4,320 hours).[167] We seek comment on

[159] For example, limiting element data are already required to be made publicly available for certain constrained paths under § 37.6(a)(2)(ii) of the Commission's regulations. 18 CFR 37.6(a)(2)(ii) (2023).

[160] Either the operating hour or the future hour closest to the operating hour for which the transmission provider calculates ATC, hereafter simply ''operating hour'' for conciseness.

[161] This approach reflects that the Commission's regulations already consider posted paths that have an ATC that is less than or equal to 25% of TTC to be ''constrained.'' *See* 18 CFR 37.6(b)(1)(ii).

[162] *See infra* P 156.

[163] For denials or curtailments of service the date/time would be the date/time for which the service was requested.

[164] For example, if a request for 100 MW of three weeks of weekly firm point-to-point transmission service were denied, the MWh impacted would be determined as (100 MW) * (3 weeks) * (7 days/week) * (24 hours/day) = 50,400 MWh.

[165] For example, if in the proceeding example 75 of the requested 100 MW were ultimately granted, then the MWh impacted would be determined as (25 MW) * (3 weeks) * (7 days/week) * (24 hours/day) = 12,600 MWh.

[166] For example, if a transmission provider curtailed an instance of transmission service by 25 MW for a period of 2 hours, then the impacted MWh would be determined as (25 MW) * (2 hours) = 50 MWh. Similarly, if a transmission provider redispatched down one if its network customer's network resources by 75 MW for 2 hours, then the impacted MWh would be determined as (75 MW) * (2 hours) = 150 MWh.

[167] For example, if a request to designate a network resource with a capacity of 500 MW is denied, then the impacted MWh would be determined as (500 MW) * (4,320 hours) = 2,160,000 MWh.

the use of this assumed duration, or whether a different assumed duration or another approach would result in a better consideration of the congestion reflected in denials of requests to designate network resources or load.

(iv) LER Threshold

135. We seek comment on what LER metric threshold would be appropriate to identify transmission lines that are sufficiently congested to be subject to a wind requirement, along with an estimate of how many transmission lines would meet any discussed threshold. As proposed above, the LER measurement that will be compared to such a threshold would be measured in impacted MWh. One potential approach is to attempt to identify an LER threshold that would be the rough equivalent of any congestion cost threshold that we might ultimately adopt for RTO/ISO regions (discussed above), given an assumed cost of impacted MWh. For example, if one assumes a cost of an impacted MWh of $100, then an LER threshold that would be the rough equivalent of a $1 million RTO/ISO congestion cost threshold would be calculated as ($1,000,000)/($100/MWh) = 10,000 MWh. However, this would only be a rough equivalence because what is measured by LER and the congestion cost that we propose to be measured for RTO/ISO regions are not reflective of the exact same events, and any assumption for the cost of an impacted MWh will necessarily need to be some estimate of the average cost of such MWh. Another potential approach is to use hourly systemwide incremental costs, which are already required to be used for both energy imbalances under Schedule 4 and generator imbalances under Schedule 9 of the *pro forma* OATT, to calculate an estimated cost of impacted MWh.[168] We seek comment on the costs that transmission providers include in hourly energy or generator imbalance charges, in particular whether these charges reflect only the energy component or a full redispatch cost, including congestion and production costs. Finally, we seek comment on whether using a different value, or another approach altogether, to identify transmission lines that should be subject to a potential wind requirement would be appropriate.

(2) Potential Alternatives for Comment

136. We seek comment on alternatives to our preliminary proposal of using LER as a proxy for congestion in non-RTO/ISO regions. In particular, we seek comment on the possibility of using information that is currently non-public, such as redispatch costs, to measure actual congestion costs that are incurred in non-RTO/ISO regions.

(i) Non-RTO/ISO Congestion Costs

137. As an alternative to the LER metric, we seek comment on whether non-RTO/ISO regions could measure congestion costs to identify candidate transmission lines for a potential wind requirement. Under section 33.2 of the *pro forma* OATT, a transmission provider must perform redispatch of resources on a least-cost basis, without consideration of whether a resource is owned by the transmission provider or a network customer.[169] Based on this requirement, we believe that transmission providers consider redispatch costs for both network resources and their own resources serving their native load, although the information on such costs may currently be non-public. Such congestion costs could be measured within non-RTO/ISO regions for the purpose of identifying transmission lines that would benefit the most from a potential wind requirement. Because we believe such costs are formally tracked and associated with the limiting transmission line ratings necessitating each instance of redispatch, it should be possible to attribute redispatch costs to the particular transmission line whose transmission line ratings are causing such costs. We seek comment on using redispatch costs to measure congestion costs and to what extent this approach would be preferable to the LER approach. We seek comment on measuring congestion costs at intertie locations and whether redispatch costs could be used to identify interties that would benefit the most from a potential wind requirement.

138. We also seek comment on whether measuring congestion costs in non-RTO/ISO regions should be used in *conjunction* with an approach like the LER approach (*i.e.,* congested transmission lines would be identified through some combination of how much redispatch cost their transmission line ratings cause *and* how many MWh are impacted by denials, disruptions, etc.).[170] If using a combined approach, we seek comment on how these components should be used together, *e.g.,* how much weight each measure of congestion is given, to develop an overall indicator of how congested a transmission line in a non-RTO/ISO region is.

139. Finally, we seek comment on additional methods for calculating congestion costs both within non-RTO/ISO regions and at interties connecting with non-RTO/ISO regions. For instance, average hourly incremental/decremental cost (that transmission providers are required to use under *pro forma* OATT Schedules 4 and 9 in the calculation of hourly imbalances charges discussed above) or electricity hub prices could be used to estimate congestion costs.

c. Self-Exceptions From the Wind Requirement

i. Self-Exception Categories

140. We preliminarily propose to allow transmission providers to self-except a transmission line from the wind requirement if it determines, consistent with good utility practice: (1) that the transmission line rating is not affected by wind conditions; or (2) that implementing the wind requirement on such a transmission line would not produce net benefits. These self-exceptions recognize that there may be instances where the congestion threshold and wind speed threshold criteria identify transmission lines that would nonetheless not be good candidates for implementation of a wind requirement. For example, certain transmission lines that might not benefit from the wind requirement, such as a partially underground transmission line where the cable is the limiting element, may nonetheless trigger the proposed criteria. As another example, applying the wind requirement to a particular transmission line may only relieve thermal constraints slightly before a voltage or stability constraint bind, resulting in little value for the cost of implementing the wind requirement.

141. Under either self-exception category, a transmission provider would log the self-exception and justification in its transmission line rating database (as outlined below). This proposal is supported by NOI comments that argue a wind requirement should provide exceptions for cost, reliability, and other negative impacts, and assert that the

[168] *See Pro forma* OATT, Schedule 4 Energy Imbalance Service. ''The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule [4] or a penalty for hourly generator imbalances under Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.'' *Id.*

[169] *Pro forma* OATT, section 33.2 (Transmission Constraints).

[170] We preliminarily assume, if a redispatch cost approach were used in conjunction with an LER approach, that the LER would be modified to (at a minimum) exclude consideration of the impacted MWh from redispatch of network resources, given that such events would already be reflected in terms of their redispatch cost.

cost exception should require a showing by the transmission provider.[171]

142. We seek comment on the concept of allowing a transmission provider to self-except transmission lines from the wind requirement.

143. The first self-exception category—that the transmission line rating is not affected by wind speed—is similar to the exception to the AAR requirement established by Order No. 881 and set forth in Attachment M of the *pro forma* OATT that permits transmission providers to use a transmission line rating that is not an AAR where the transmission line is not affected by ambient air temperature or solar heating.[172] We expect that the same (or largely the same) transmission lines that are excepted from Order No. 881's requirement to implement AARs or seasonal line ratings (because the transmission line is not affected by ambient air temperature) would be eligible for exception from the wind requirement under the first self-exception category. We seek comment on whether there are transmission lines whose transmission line ratings would not be affected by wind speed and whether the first self-exception category is appropriate in such cases.

144. To implement the second self-exception category, we preliminarily propose that transmission providers conduct a net benefit analysis that sums all of the anticipated benefits attributable to the implementation of the wind requirement on the relevant line and, similarly, sums all of the costs attributable to the wind requirement on the relevant line. If the benefits do not exceed the costs, then a transmission provider may self-except the transmission line. Examples of benefits that could be considered in a net benefit analysis include: production cost savings (including increased transmission capacity, reduced congestion costs, reduced dispatch costs, and other related factors), and deferred costs of new transmission lines. Examples of costs in a net benefit analysis include: the installation of sensors, as well as the communications equipment or other costs attributable to implementing the wind requirement at the specified location or on the specified transmission lines. We preliminarily propose that transmission providers would not include, in the net benefit analysis, costs that they must incur to implement DLRs generally, *i.e.,* for communication equipment needed for enterprise-wide DLR implementation, computer hardware and software, EMS, physical security, and cybersecurity protections. We seek comment on the net benefit analysis proposal, including the potential benefits and costs to include in the analysis; whether there are costs or benefits that should *not* be included in a net benefits analysis; whether the Commission should specify which costs and benefits can or should be included in a net benefits analysis; whether such determinations should be left to the transmission providers' discretion; and whether transmission providers should be required to specify in their tariffs which costs and benefits can or must be included in a net benefits analysis. We also seek comment on whether benefits attributable to a wind requirement and used in a net benefits analysis should be limited to a particular time horizon, such as 10 years; or how transmission providers should attribute costs, including whether treatments such as amortization or depreciation would be appropriate, for purposes of the net benefits analysis, and the relevant time horizon.

145. We also preliminarily propose that a transmission provider that makes a self-exception finding must document, in its database of transmission line ratings and transmission line rating methodologies on OASIS or another website with authentication control including multi-factor authentication,[173] any exceptions to the wind requirement, including the nature of and basis for each exception, the date(s) and time(s) that the exception was initiated, and (if applicable) documentation of the net benefit analysis calculation, methodology, and assumptions. We seek comment on this approach to justifying and documenting self-exceptions.

146. Under this preliminary proposal, a transmission provider would not be required to implement the wind requirement on a specific transmission line if it takes a self-exception for that particular transmission line, but a self-exception would not reduce the transmission provider's overall implementation burden with respect to the wind requirement that year. A transmission provider would still be required to implement the wind requirement on its next most congested transmission line, unless no further transmission lines met the criteria for the wind requirement that year.

147. Furthermore, under our preliminary proposal, a transmission provider would be required to reevaluate and log any exceptions taken every year during the annual wind requirement implementation cycles for the wind requirement as discussed in the IV.B. Compliance and Transition and Implementation Timelines section. In some instances, this proposal may merely require a review of the inputs and assumptions to the original self-exception analysis, to verify that they have not changed. In other instances, if such inputs and assumptions have changed, then analyses would need to be updated. If the technical basis for an exception is found to no longer apply, the transmission provider would be required to update the relevant transmission line rating(s) in a timely manner. We seek comment on this proposal for annual re-evaluations of self-exceptions, including whether another timeframe is more appropriate. We seek comment on the information that should be included in the transmission line rating log to justify a self-exception under either self-exception finding.

148. We note that Order No. 881 and the System Reliability section of the *pro forma* OATT Attachment M provides for the temporary use of a transmission line rating different than would otherwise be required if such rating is determined to be necessary to ensure the safety and reliability of the transmission system.[174] Under this preliminary proposal, we would maintain that System Reliability provision in Attachment M, which would similarly apply to any

[171] ELCON Comments, Docket No. AD22–5, at 8–9 (filed Apr. 25, 2022); R Street Institute Comments, Docket No. AD22–5, at 5–6 (filed Apr. 26, 2022).

[172] *See* Order No. 881, 177 FERC ¶ 61,179 at P 227; *see supra* P 84 (discussing the self-exception that would apply to the proposed requirement to include solar heating in transmission line ratings).

[173] While prior Commission orders, including Order No. 881, have references to ''password-protected websites'' instead of website(s) with authentication control, NAESB standards that incorporate NIST standards require utilities to use authentication control, including multi-factor authentication, on their OASIS websites or any alternative websites. *See* National Institute of Standards and Technology, *NIST Special Publication 800–63B* (Oct. 2023), *https://pages.nist.gov/800-63-3/sp800-63b.html;* North American Energy Standards Board, *Standards for Business Practices and Communication Protocols for Public Utilities* 5 (Mar. 2020), *https://www.naesb.org/pdf4/naesb_033020_weq_version_003.3_report.pdf* (''In response, the subcommittees revised WEQ–002–5 to require transmission providers or the agent to whom a transmission provider has delegated the responsibility of meeting any requirements associated with OASIS, referred to as a Transmission Services Information Provider ('TSIP'), to apply industry-recognized best practices in the implementation and maintenance of OASIS nodes and supporting infrastructure. Included in these modifications is a requirement that TSIPs must implement guidelines for user passwords and authentication aligned with NIST SP 800–63B.''). As such, we believe that this text does not impose any new requirements on utilities. The Commission has adopted these NAESB standards. *See Standards for Bus. Pracs. & Communication Protocols for Pub. Utils.,* Order No. 676–J, 86 FR 29491 (June 2, 2021), 175 FERC ¶ 61,139 (2021).

[174] Order No. 881, 177 FERC ¶ 61,179 at P 232; *pro forma* OATT, attach. M (System Reliability).

transmission lines to which the wind requirement would otherwise apply.

ii. Challenges to Self-Exceptions

149. We propose to allow any person that disagrees with a transmission provider's self-exception to challenge that self-exception by filing a complaint with the Commission under FPA section 206. Examples of potential complaints concerning a transmission provider's self-exceptions could include that a transmission provider improperly claimed that the transmission line is not affected by wind speed, or that a transmission provider made a faulty demonstration that the transmission line ratings subject to wind requirement would not produce net benefits on the transmission line, such as through improper calculations of costs or benefits. The Commission could also institute an investigation under FPA section 206 on its own motion to examine any self-exception. We seek comment on whether there should be another means to challenge a self-exception.

d. Transmission Lines Formerly Subject to the Wind Requirement

150. In cases when a transmission provider determines that a transmission line subject to a wind requirement no longer exceeds the thresholds for high levels of congestion and wind speed, we preliminarily propose that the wind requirement no longer apply to the transmission line and that transmission providers will no longer be required to include wind conditions when calculating the transmission line rating. For example, the transmission provider would be permitted, *inter alia,* to decommission the sensors if any, on that transmission line. Similarly, if a transmission provider determines that a transmission line previously subject to a wind requirement is no longer expected to produce net benefits, then we preliminarily propose that the wind requirement no longer apply to the transmission line and that the transmission provider will no longer be required to include wind measurements when calculating the transmission line rating and the transmission provider would be permitted to decommission any sensors on that transmission line. We further preliminarily propose that, when calculating the net benefits of a wind requirement to determine if a particular transmission line should be subject to the wind requirement sunk costs, such as past installations of sensors, should not be included. Under the preliminary proposal, such transmission providers would be required to document their decision to stop applying the wind requirement and to decommission any sensors and provide a justification. Similar to the proposed self-exception process, transmission providers would log such decision, including the nature of and basis for each decommissioning, the date(s) and time(s) that the decommissioning was initiated, and (if applicable) documentation of the net benefit analysis calculation, methodology, and assumptions in their database of transmission line ratings and transmission line rating methodologies on OASIS or another website with authentication control including multi-factor authentication at least one year prior to the decommissioning. A justification could be, for example, that a transmission line no longer meets the congestion or wind speed thresholds or that the wind requirement no longer provides net benefits on a transmission line. Such justifications for removing the wind requirement would be subject to the same opportunities to be challenged pursuant to FPA section 206 discussed above for the self-exception process. Also, a goal of applying DLRs, including the wind requirement, to a transmission line is to reduce congestion. It stands to reason that a transmission line that is subject to the wind requirement may experience less congestion because of the wind requirement, such that it no longer meets the congestion threshold. In such cases, it may be counterintuitive to remove the wind requirement. As such, we preliminarily propose that any decision to remove the wind requirement from a transmission line must examine and compare the congestion with the wind requirement in place against the estimated congestion if the wind requirement were not in place. We seek comment on this preliminary proposal for a decommissioning process. Further, we seek comment on the costs and other burdens associated with decommissioning DLR equipment. We also seek comment on whether the threshold criteria should be required to no longer be met for a longer period of time (*e.g.,* 5 years) before decommissioning is allowed.

e. Potential Transparency Reforms and Request for Comment

151. We preliminarily propose new transparency reforms, including requirements to enhance data reporting practices related to congestion in non-RTO/ISO regions to identify candidate transmission lines for a wind requirement, and posting and retention of congestion data in both RTO/ISO and non-RTO/ISO regions. The proposed reforms will provide transparency into the transmission providers' identification of transmission lines that would be subject to the wind requirement and enable the Commission and stakeholders to verify the transmission providers' analysis. Order No. 881 already requires a database of transmission line ratings and methodologies to be posted.[175] This posting requirement would extend to transmission line ratings on transmission lines subject to the solar and wind requirements as well.

152. Some commenters in the NOI proceeding support adopting the same transparency measures for transmission lines subject to a wind requirement as the Commission adopted in Order No. 881.[176] In addition, some commenters support going further and requiring the filing and posting of informational reports on which transmission lines meet the Commission's wind requirement criteria, as well as the transmission line ratings and methodologies used for implementation of the wind requirement.[177]

153. As noted in section III. The Potential Need for Reform above, we preliminarily find that existing transmission line ratings and transmission line rating methodologies may result in unjust and unreasonable wholesale rates that result from inaccurate transmission line ratings. In addition to the preliminarily proposed reforms described above, we make a concomitant preliminary finding that certain transparency reforms are necessary to implement the preliminary proposal. In addition to the requests for comments on specific aspects of the preliminary proposal, we seek comment on whether the proposed data reporting practices related to congestion in non-RTO/ISO regions that would identify transmission lines that are candidates for a wind requirement and the posting

[175] *See* Order No. 881, 177 FERC ¶ 61,179 at PP 330, 336–340. The transmission provider must post the information on the password-protected section (or section subject to authentication control including multi-factor authentication) of its OASIS site or on another website with authentication control including multi-factor authentication. *Id.* P 336; *see supra* n.200.

[176] DC Energy Comments, Docket No. AD22–5, at 4 (filed Apr. 25, 2022); LADWP Comments, Docket No. AD22–5, at 4–5 (filed Apr. 25, 2022); PJM Comments, Docket No. AD22–5, at 6–7 (filed May 9, 2022); TAPS Comments, Docket No. AD22–5, at 8 (filed Apr. 25, 2022).

[177] DC Energy Comments, Docket No. AD22–5, at 5 (filed Apr. 25, 2022); ELCON Comments, Docket No. AD22–5, at 2, 8–9, 11 (filed Apr. 25, 2022); LADWP Comments, Docket No. AD22–5, at 4–5 (filed Apr. 25, 2022); R Street Institute Comments, Docket No. AD22–5, at 9 (filed Apr. 26, 2022); TAPS Comments, Docket No. AD22–5, at 7 (filed Apr. 25, 2022); WATT/CEE Comments, Docket No. AD22–5, at 9 (filed Apr. 25, 2022).

of underlying congestion data, as set forth below, would result in just and reasonable rates.

i. Potential Reforms to Congestion Data Collection

154. As preliminarily proposed above in section IV.A.3.b.iii.b.1. Limiting Element Rate, transmission providers would be required to maintain a database of the following events: (1) denials of requested firm point-to-point transmission service; (2) denials of requests to designate network resources or load; (3) curtailment of firm point-to-point transmission service under section 13.6 of the *pro forma* OATT; (4) curtailment of network integration transmission service or secondary network integration transmission service under section 33 of the *pro forma* OATT; and (5) redispatch of network integration transmission service or secondary network integration transmission service under sections 30.5 and 33 of the *pro forma* OATT. Specifically, as preliminarily proposed above, transmission providers would be required to record for each event: (1) date/time of the record being added to the database; (2) dates and times of the start and end of the event; (3) event type; (4) specification of the transmission line with a transmission line rating that was the limiting element causing the event; and (5) the MWh of transmission service (or potential transmission service) that was impacted by the event. We seek comment on this preliminary proposal to require transmission providers to record this LER metric data, including the changes in data collection practices it would cause, and the associated burden. We seek comment on whether data identifying limiting transmission lines during all the periods of congestion listed above already exist, and whether the above descriptions of those events (duration, energy impacted, etc.) are being recorded by transmission providers and/or posted in OASIS currently. We also seek comment on the challenges in data collection practices and associated burden required to record the alternative methods to estimate congestion costs in non-RTO/ISO regions and at non-RTO/ISO seams discussed above in section IV.A.3.b.iii.b.2.i Non-RTO/ISO Congestion Costs such as recording redispatch costs caused with a given transmission constraint.

155. As discussed below in section IV.4. Requirements for Reflecting Solar and/or Wind in Transmission Line Ratings in RTOs/ISOs, we preliminarily propose that RTOs/ISOs would use the LER metric only for congestion at their seams, and not on the internal transmission lines for which they have explicit congestion data. However, we also preliminarily propose to require that transmission providers in RTOs/ISOs maintain data on annual overall congestion costs caused by binding constraints on each transmission line. Finally, we also seek comment on whether any changes or additional data requirements would be needed to track congestion costs, or causes of congestion costs, in RTO/ISO regions.

ii. Posting of Congestion Data

156. Similar to the Commission's determination in Order No. 881, we preliminarily propose to require transmission providers to post on OASIS or another website with authentication control including multi-factor authentication the new congestion databases associated with this rulemaking, such as an LER metric database, with a data retention requirement of at least five years. We preliminarily find that, without further transparency, the Commission and market participants would not have the information needed to determine the transmission lines on which transmission providers in non-RTO/ISO regions are required to implement the wind requirement.

157. We seek comment on this congestion data transparency proposal, including whether the congestion data proposed to be recorded in the congestion databases or other elements should be posted on OASIS or another website with authentication control including multi-factor authentication. We also seek comment on posting on OASIS or another website with authentication control including multi-factor authentication the data associated with the alternative methods to estimate congestion costs in non-RTO/ISO regions and at seams with non-RTO/ISO regions discussed above in section IV.A.3.b.iii.b.2.i Non-RTO/ISO Congestion Costs such as recording redispatch costs caused by a given transmission constraint. We also seek comment on whether posting of additional congestion cost data, beyond the overall congestion costs caused by binding constraints on each transmission line, should be required in RTO/ISO regions. We seek comment on whether a different data posting, access restrictions, and data retention requirement is appropriate.

iii. Posting of Transmission Line Ratings Subject to a Wind Requirement

158. In Order No. 881, the Commission required the maintenance and posting of all transmission line ratings in a line rating database.[178] That requirement would apply to any transmission line ratings under a potential final rule in this proceeding as well.[179]

159. However, given the unique circumstances surrounding a potential wind requirement, including the need to be able to evaluate the effectiveness of such a requirement, we preliminarily propose that, for transmission lines subject to a wind requirement, the transmission provider would be required to post the transmission line ratings for each period calculated both with *and without* the consideration of forecasted wind conditions. We preliminarily believe that the posting of both transmission line ratings for the periods in which the wind requirement applies would provide the transparency necessary to evaluate the effectiveness of implementing the wind requirement on each transmission line subject to the wind requirement. We seek comment on this proposed posting requirement.

4. Requirements for Reflecting Solar and/or Wind in Transmission Line Ratings in RTOs/ISOs

160. In Order No. 881, the Commission required AARs to be used (1) in the day-ahead and real-time energy markets, (2) in any reliability or intra-day reliability unit commitment processes, and (3) for transmission service over RTO/ISO seams.[180] The Commission declined to apply the AAR requirement to the evaluation of internal point-to-point or through-and-out transactions.[181] The Commission explained that the vast majority of energy transactions in RTOs/ISOs are executed and financially settled in the day-ahead and real-time markets, and thus requiring AARs to be used for internal point-to-point and through-and-out transactions would provide very little additional benefits in the RTO/ISO markets.[182]

161. For the solar requirement, which we propose to apply to all transmission lines, we preliminarily propose that RTOs/ISOs use transmission line ratings that reflect solar heating based on the sun's position and forecastable cloud cover in their day-ahead and real-time markets as well as for seams transactions that are near-term transmission service (*i.e.,* that start and

[178] Order No. 881, 177 FERC ¶ 61,179 at PP 330, 336; *see pro forma* OATT, attach. M (Obligations of Transmission Provider).

[179] *See pro forma* OATT, attach. M, Obligations of Transmission Provider; *see also* Order No. 881, 177 FERC ¶ 61,179 at PP 330, 336–340.

[180] Order No. 881, 177 FERC ¶ 61,179 at P 89.

[181] *Id.* P 134.

[182] *Id.*

stop within the next 10 days). We do *not* propose to require RTOs/ISOs to use such transmission line ratings for internal point-to-point transmission service or through-and-out service.

162. For the wind requirement, which we propose to apply only to select transmission lines, we preliminarily propose a different approach. Specifically, we preliminarily propose that RTOs/ISOs comply with the wind requirement [183] by using transmission line ratings that reflect up-to-date forecasts of wind speed and wind direction: (1) in their day-ahead and real-time markets; and (2) for seams transactions, internal point-to-point transmission service, and for through-and-out service that are 48-hour transmission services (*i.e.,* that start and end within 48 hours of the request). We preliminarily propose this broader requirement for these transmission lines because we preliminarily believe that the additional accuracy of using the transmission line ratings that incorporate the wind requirement on highly congested transmission lines may justify the burden.

163. We seek comment on these preliminary proposals for applying the proposed solar and wind requirements to transmission line ratings in RTOs/ISOs. In particular, we seek comment on whether RTOs/ISOs should instead *not* be required to apply the wind requirement for internal point-to-point and through-and-out transactions, consistent with the AAR requirements of Order No. 881 and the instant proposal for the potential solar requirement.

5. Implications for Emergency Ratings

164. In Order No. 881, the Commission required that transmission providers use uniquely determined emergency ratings for contingency analysis in the operations horizon and in post-contingency simulation of constraints. The Commission also required that such emergency ratings include separate AAR calculations for each emergency rating duration used.[184]

165. We preliminarily propose to require that all uniquely determined emergency ratings used for contingency analysis in the operations horizon and in post-contingency simulation of constraints must reflect solar heating based on the sun's position and up-to-date forecasts of forecastable cloud cover. We preliminarily find that applying the solar requirement to both normal and emergency ratings will enhance the accuracy of transmission line ratings. We seek comment on this proposed approach.

166. In addition, for transmission lines subject to a wind requirement, we preliminarily propose to require that all uniquely determined emergency ratings used for contingency analysis in the operations horizon and in post-contingency simulation of constraints must reflect up-to-date forecasts of wind speed and direction, consistent with the wind requirement for normal ratings. We preliminarily find that, for transmission lines that will be subject to a wind requirement, reflecting wind conditions in both normal and emergency ratings will enhance the accuracy of transmission line ratings. We seek comment on this proposed approach.

6. Confidence Levels

167. In statistical forecasting, ''quantile forecasting'' is the practice of forecasting upper or lower limits of a particular future observation.[185] Quantile forecasting is the type of forecasting typically involved with determining transmission line ratings: forecasters seek to predict the extreme values (upper or lower, depending on the variable) of weather variables that serve as inputs into transmission line rating calculations, and to calculate sufficiently conservative transmission line ratings from those forecasts. In quantile forecasting, a ''confidence level'' reflects how much certainty forecasters have that a particular observation will not exceed their forecast when the observation is repeated many times. For example, if each day a meteorologist publishes a forecast of next-day high temperatures, and the method for producing such forecast is designed to meet a 98% confidence level, then over time the corresponding observed high temperatures should be less than or equal to such forecasts 98% of the time.

168. We understand that line ratings always have an associated confidence level. Because such confidence levels are typically relatively high, such as 98%, in most instances the forecasted transmission line ratings are conservative, such that the observed weather (when that forecasted hour becomes the operating hour) is within the range predicted by the forecast. However, infrequently, as the forecast for a given hour is updated it could cause a transmission provider to have to manage (through curtailments or other actions) a reduction in transmission capability from what had been previously forecasted.

169. The Commission's outreach and research indicate that it is commonplace for DLRs to be calculated to a default confidence of 98%. We preliminarily believe that there may be some benefit to having a default confidence level for calculations of transmission line ratings subject to the solar and/or wind requirement across regions: first, to discourage the use of overly conservative confidence levels, which will erode the benefits of using weather forecasts; [186] and second, to ensure that sharply differing practices do not produce sharply different transmission line ratings.

170. Given the importance of confidence levels to transmission line ratings accuracy and reliability, we seek comment on whether the Commission should establish a default confidence level transmission providers are required to use when calculating transmission line ratings subject to the solar and/or wind requirement, unless they document a particular reason for needing and using a different confidence level. If so, we seek comment on what such a default confidence level should be, and how the use of confidence levels different from the default should be documented by transmission providers to justify such deviations.

171. If such a default confidence level were adopted, we preliminarily propose that it apply *not* to the underlying weather forecasts (wind speed, wind direction, ambient air temperature, solar heating, etc.) individually, but instead to the forecast of the transmission line rating overall. We preliminarily believe that applying the default confidence level to the underlying weather forecasts would result in a confidence level for the overall forecasted transmission line rating that is less than the default level. We seek comment on this proposal to apply any default confidence level to overall transmission line rating forecasts. We seek comment on what confidence levels are currently typically applied to different types of transmission line ratings.

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[183] Transmission lines subject to the wind requirement are also subject to the solar requirement, as described above in section IV.A.3 Potential Wind Requirement.

[184] *Id.* P 297; *pro forma* OATT, attach. M, Obligations of Transmission Provider.

[185] *See, e.g.,* Electric Power Systems: Advanced Forecasting Techniques and Optimal Generation Scheduling, section 5 at 20 (João P.S. Catalão ed., 2017).

[186] In Order No. 881 the Commission acknowledged that ''transmission line ratings using unreasonably high forecast margins would also yield inaccurate transmission line ratings and, in turn, would result in an underutilization of existing transmission facilities, price signals based on less transfer capability than is truly available, and wholesale rates that are unjust and unreasonable.'' Order No. 881, 177 FERC ¶ 61,179 at P 52.

B. Compliance and Transition and Implementation Timelines

1. Pro Forma OATT Revisions and Implementation

172. We preliminarily propose to promulgate these potential reforms through revisions to the *pro forma* OATT, which is applicable to all transmission providers. We seek comment on this proposal including whether such requirements should be reflected in Attachment M of the *pro forma* OATT or elsewhere. Commenters are invited to propose *pro forma* OATT language, including proposed revisions to existing *pro forma* OATT language, and to explain why such language would be appropriate.

173. While the requirements we preliminarily propose here would be imposed on transmission providers, we recognize as we did in Order No. 881 that transmission owners determine transmission line ratings.[187] In many instances, particularly outside of RTOs/ISOs, the transmission provider and transmission owner are the same entity. However, within RTOs/ISOs and in limited other instances, the transmission provider and transmission owner are separate entities. For such instances, we preliminarily propose that the limit for how many transmission lines must apply the wind requirement, for any transmission lines that meet the thresholds, (*i.e.,* the proposed 0.25% of the total number of the transmission providers' transmission lines for the initial period) apply to each individual transmission owner and not to the transmission provider on an RTO-wide basis.[188] We also preliminarily propose that transmission owners will determine transmission line ratings for all of their transmission lines. We also propose to require transmission owners to provide their transmission line ratings and transmission line rating methodology to the transmission provider. We seek comment on this aspect of the preliminary proposal, including which responsibilities would or should be carried out by transmission providers and transmission owners, whether such roles and responsibilities should be set forth in *pro forma* OATT provisions or left to RTO/ISO compliance proceedings, and how transmission providers should ensure that transmission owners appropriately perform their responsibilities.

2. Implementation Timeframe for the Solar Requirement

174. Recognizing that the proposed solar requirement may not require installing sensors, we preliminarily propose that this requirement be met no more than twelve months after any final rule is published in the **Federal Register**. We seek comment on the timeframe necessary to implement the proposed solar requirement. We seek comment on whether the clear-sky component and cloud cover component of a proposed solar requirement should have different implementation deadlines.

3. Phased-In Implementation Timeframe for the Wind Requirement

a. Annual Wind Requirement Implementation Cycles

175. We preliminarily propose to require transmission providers to undertake an annual wind requirement implementation cycle. Starting with the effective date of any potential final rule, transmission providers would gather congestion data for each transmission line for one year, as described above in section IV.A.3.b.iii. Congestion Threshold, and determine during that year which of their transmission lines meet the wind speed threshold, as described above in section IV.A.3.b.ii. Wind Speed Threshold. Finally, for any transmission lines that meet the determined wind speed and congestion thresholds, transmission providers would have six months to implement the necessary systems, based on the minimum implementation requirement as described above in section IV.A.3.b.i. Number of Transmission Lines Subject to the Wind Requirement Annually, to implement the wind requirement. This proposal aims to provide ample time for transmission providers to use congestion data that reflect implementation of AARs as required by Order No. 881, while also ensuring that a wind requirement is applied to transmission lines that would benefit from a wind requirement within a reasonable timeframe. We seek comment on this proposed approach. We specifically seek comment on the duration of the data collection period, and implementation period. While we believe one year of congestion data will be sufficient for the first implementation cycle, we seek comment on whether this is the appropriate time period for data collection and whether the Commission should mandate a different timeframe for subsequent cycles (*e.g.,* for cycle two, whether transmission providers should consider two years of congestion data). We also seek comment on whether the Commission should set a limit on the vintage of the congestion data (*i.e.,* whether congestion data from five years ago is stale and no longer relevant). We also seek comment on how this approach should change if the Commission does not require sensors for the wind requirement.

176. Most commenters argue that the Commission should not require implementation of any DLR requirements until after transmission providers have implemented AARs in July 2025 and gained experience with the use of AARs.[189] While not explicitly tied to Order No. 881, the preliminary proposal, if adopted in a final rule, is intended to reflect the importance of having adequate data for the purpose of identifying transmission lines where the wind requirement would be implemented, particularly in light of the likely changing congestion patterns after the implementation of Order No. 881. The Commission seeks comment on when implementation of the proposal should commence.

177. We seek comment on the preliminary proposal to use an annual implementation cycle. We also seek comment on whether the proposed annual implementation period would accurately identify transmission lines for implementation of the wind requirement or if the Commission should require (or allow, if preferred) a lower frequency (such as every two to three years) of cycles and higher lines-per-cycle limit for the wind requirement cycle.

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[187] *See* Order No. 881, 177 FERC ¶ 61,179 at P 140; *see also id.* P 300 (requiring transmission providers, where the transmission provider is not the transmission owner, to include in its compliance filing and implementation of *pro forma* Attachment M, that the transmission owner has the obligation for making and communicating to the transmission provider the timely calculations and determinations related to emergency ratings).

[188] For example, if an RTO has four transmission owners, each with 1,600 transmission lines, each transmission owner would be required to implement DLRs on at least four transmission lines per year (provided that at least that many transmission lines meet the criteria discussed above). The potential requirement would not be implemented by the RTO transmission provider on 16 transmission lines on an RTO-wide basis.

[189] AEP Reply Comments, Docket No. AD22–5, at 4–5 (filed May 25, 2022); APPA/LPPC Comments, Docket No. AD22–5, at 12–13 (filed Apr. 25, 2022); APS Comments, Docket No. AD22–5, at 14 (filed Apr. 25, 2022); CAISO Comments, Docket No. AD22–5, at 2 (filed Apr. 25, 2022); EEI Comments, Docket No. AD22–5, at 33 (filed Apr. 25, 2022); ELCON Comments, Docket No. AD22–5, at 12 (filed Apr. 25, 2022); ISO–NE Comments, Docket No. AD22–5, at 5–6 (filed Apr. 25, 2022); ITC Comments, Docket No. AD22–5, at 15 (filed Apr. 25, 2022); MISO Comments, Docket No. AD22–5, at 8 (filed Apr. 25, 2022); NYISO Comments, Docket No. AD22–5, at 1–2 (filed Apr. 25, 2022); Potomac Economics Comments, Docket No. AD22–5, at 3 (filed Apr. 26, 2022); Southern Company Comments, Docket No. AD22–5, at 11 (filed Apr. 25, 2022); Tri-State Comments, Docket No. AD22–5, at 4 (filed Apr. 25, 2022).

b. Transmission Provider Compliance Requirement

178. As described above in section IV.A.3.b.i. Number of Transmission Lines Subject to the Wind Requirement Annually, we preliminarily propose that transmission providers be required to implement the wind requirement on the whole number greater than 0.25% (or 1 in 400) of the transmission provider's transmission lines in each annual implementation cycle. As described above, transmission providers would be required to implement the wind requirement only on transmission lines that meet the congestion threshold and wind speed threshold.

179. We preliminarily propose to require transmission providers to implement the wind requirement on candidate transmission lines starting with the most highly congested transmission line (based on the congestion metric value, as discussed above) and moving on to the next most highly congested transmission line, and so on. This process would continue until either the yearly implementation requirement is met or there are no more candidate transmission lines waiting for implementation of the wind requirement.

c. Compliance for Transmission Providers That Are Subsidiaries of the Same Public Utility Holding Company

180. Transmission providers (or transmission owners in cases where the transmission owners and transmission provider are not the same entity) that are operating company subsidiaries of the same public utility holding company may operate their transmission facilities as a single transmission system. We seek comment on whether such transmission systems should be counted together for purposes of the transmission providers' compliance with any wind requirement, such as for counting the transmission providers' total number of transmission lines and for determining the number of transmission lines that would be included in the transmission providers' implementation cycle. This may result in implementation of the wind requirement being distributed unevenly across transmission providers that are operating company subsidiaries of the same public utility holding company. We seek comment on whether transmission providers in such situations, or the RTOs/ISOs of which they are members, should propose on compliance how they would treat such transmission providers and transmission systems.

V. Comment Procedures

181. The Commission invites interested persons to submit comments on the matters and issues proposed in this ANOPR to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due October 15, 2024 and Reply Comments are due November 12, 2024. Comments must refer to Docket No. RM24–6–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

182. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *https://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software must be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

183. Commenters that are not able to file comments electronically may file an original of their comment by USPS mail or by courier-or other delivery services. For submission sent via USPS only, filings should be mailed to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street NE, Washington, DC 20426. Submission of filings other than by USPS should be delivered to: Federal Energy Regulatory Commission, 12225 Wilkins Avenue, Rockville, MD 20852.

VI. Document Availability

184. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*https://www.ferc.gov*).

185. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

186. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Rosner is not participating.

Issued: June 27, 2024.

Debbie-Anne A. Reese,

Acting Secretary.

Note: The following appendix will not appear in the Code of Federal Regulations.

Appendix A: List of Short Names/Acronyms of Commenters in Docket No. AD22–5

Short name/acronym	Commenter
AEP	American Electric Power Company, Inc.
APPA/LPPC	American Public Power Association (APPA) and the Large Public Power Council (LPPC).
APS	Arizona Public Service Company.
BPA	Bonneville Power Administration. The BPA Comments were filed as appendix B to the DOE Comments and were not submitted as a separate filing. Pagination cited in the ANOPR is internal to the BPA Comments.
CAISO	California Independent System Operator Corporation.
Certain TDUs	Certain Transmission Dependent Utilities consist of: Alliant Energy Corporate Services, Inc. (Alliant Energy), Consumers Energy Company (Consumers Energy), and DTE Electric Company (DTE Electric).
Clean Energy Parties	Natural Resources Defense Council, Sustainable FERC Project, Southern Environmental Law Center, Western Resource Advocates, Conservation Law Foundation, RMI, and Fresh Energy.
DC Energy	DC Energy, LLC.
DOE	United States Department of Energy.

Short name/acronym	Commenter
EEI	Edison Electric Institute.
EGM	Electrical Grid Monitoring.
ELCON	Electricity Consumers Resource Council.
Entergy	Entergy Services, LLC.
Idaho Power	Idaho Power Company.
ISO–NE	ISO New England Inc.
ITC	International Transmission Company d/b/a ITC Transmission, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC.
LADWP	Los Angeles Department of Water and Power.
LineVision	LineVision, Inc.
MISO	Midcontinent Independent System Operator, Inc.
NERC	North American Electric Reliability Corporation.
NRECA	National Rural Electric Cooperative Association.
NYISO	New York Independent System Operator, Inc.
NYTOs	The New York Transmission Owners consist of: Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Niagara Mohawk Power Corporation d/b/a National Grid; New York Power Authority; New York State Electric & Gas Corporation; Orange and Rockland Utilities, Inc.; Long Island Power Authority; and Rochester Gas and Electric Corporation.
OMS	Organization of MISO States.
Potomac Economics	Potomac Economics, Ltd.
PPL	PPL Electric Utilities Corporation.
R Street Institute	R Street Institute.
Southern Company	Southern Company Services, Inc. acting as agent for Alabama Power Company, Georgia Power Company, and Mississippi Power Company.
TAPS	Transmission Access Policy Study Group.
Tri-State	Tri-State Generation and Transmission Association, Inc.
TS Conductor	TS Conductor Corporation.
WATT/CEE	Working for Advanced Transmission Technologies (WATT) and Clean Energy Entities (CEE), which consist of American Clean Power Association, Advanced Energy Economy, and the Solar Energy Industries Association.

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