DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM20–16–000; Order No. 881]

Managing Transmission Line Ratings

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is revising both the *pro forma* Open Access Transmission Tariff and the Commission's regulations under the Federal Power Act to improve the accuracy and transparency of electric transmission line ratings. Specifically, the Commission is requiring: Public utility transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; regional transmission organizations (RTO) and independent system operators (ISO) to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; public utility transmission providers to use uniquely determined emergency ratings; public utility transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and with market monitors in RTOs/ISOs; and public utility transmission providers to maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System site or other password-protected website.

DATES: This rule will become effective March 14, 2022.

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I. Introduction

1. In this final rule, the Federal Energy Regulatory Commission (Commission) is adopting reforms, pursuant to section 206 of the Federal Power Act (FPA),[1] to the *pro forma* Open Access Transmission Tariff (OATT) and the Commission's regulations to improve the accuracy and transparency of electric transmission line ratings used by transmission providers.[2] As discussed below, we adopt the Commission's proposal in the Notice of Proposed Rulemaking (NOPR) to define a transmission line rating as ''the maximum transfer capability of a transmission line, computed in accordance with a written transmission line rating methodology and consistent with Good Utility Practice,[3] considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the Transmission System (such as system voltage and stability limits).''[4]

2. The transfer capability of a transmission line can change with ambient weather conditions. Thus, a transmission line rating can be determined by taking into consideration the physical characteristics of the conductor and making assumptions about ambient weather conditions to determine the maximum amount of power that can flow through a conductor while keeping the conductor under its maximum operating temperature. Conductor temperatures are impacted by a variety of factors,

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

[2] In this final rule, 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 (2021). Therefore, unless otherwise noted, ''transmission provider'' refers only to public utility transmission providers. Furthermore, the term ''public utility'' as found in section 201(e) of 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).

[3] The Commission's *pro forma* OATT defines Good Utility Practice as: ''[a]ny of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).'' *Pro forma* OATT section 1.15.

[4] The definition also states, ''Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.'' *Managing Transmission Line Ratings,* Notice of Proposed Rulemaking, 86 FR 6420 (Jan. 21, 2021), 173 FERC ¶ 61,165, at P 85 (2020) (NOPR).

including ambient air temperatures. Increases in ambient air temperatures tend to increase a transmission line's operating temperature and lower a transmission line's rating, while lower ambient air temperatures tend to lower a transmission line's operating temperature and increase the transmission line's rating.

3. Many transmission line ratings are currently calculated based on assumptions about ambient conditions that are not regularly adjusted and therefore do not accurately reflect the near-term transfer capability of the transmission system.[5] For example, when seasonal or static temperature assumptions exceed actual ambient air temperatures, transmission line ratings may understate the near-term transfer capability that the transmission system can actually provide, leading to unnecessarily restricted flows and potentially increased congestion costs. Alternatively, when ambient air temperatures exceed seasonal or static temperature assumptions, transmission line ratings may overstate the near-term transfer capability of the system, creating potential reliability and safety problems. In either case, the continued use of seasonal and static temperature assumptions may result in transmission line ratings that do not accurately represent the transfer capability of the transmission system. We find that transmission line ratings and the rules by which they are established are practices that directly affect the cost of wholesale energy, capacity, and ancillary services, as well as the cost of delivering wholesale energy to transmission customers; thus, we find that inaccurate transmission line ratings result in Commission-jurisdictional rates that are unjust and unreasonable.

4. To address these issues with respect to transmission service in the near term, we adopt, with certain modifications, the NOPR proposal's definition of an ambient-adjusted rating (AAR) as a transmission line rating that: (1) Applies to a time period of not greater than one hour; (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; (3) 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 (4) is calculated at least each hour, if not more frequently.[6] Additionally, we adopt two requirements for greater use of AARs. First, we require that transmission providers—including RTOs/ISOs for transmission service at their seams[7]—use AARs as the basis for evaluation of transmission service requests that will end within 10 days of the request. Second, we require that transmission providers—including RTOs/ISOs for transmission service at their seams—use AARs as the basis for their determination of the necessity of certain curtailment, interruption, or redispatch of transmission service anticipated to occur within those 10 days.

5. To address these issues with respect to transmission service in the longer term, we require that transmission providers use seasonal line ratings as the basis for evaluation of transmission service requests ending more than 10 days from the date of the request. We also require that transmission providers use seasonal line ratings as the basis for the determination of the necessity of curtailment, interruption, or redispatch of transmission service that is anticipated to occur more than 10 days in the future.[8]

6. For both longer term and shorter term transmission service, we adopt exceptions to the AAR and seasonal line rating requirements to accommodate instances in which the transmission line rating of a transmission line is not affected by ambient air temperature and instances in which a transmission provider reasonably determines, consistent with good utility practice, that the use of a temporary alternate rating is necessary to ensure the safety and reliability of the transmission system.[9]

7. In certain situations, using transmission line ratings that are based on factors beyond forecasted ambient air temperatures and the presence or absence of solar heating may lead to greater accuracy. For example, the use of dynamic line ratings (DLRs) presents opportunities for transmission line ratings that may be more accurate than those established with AARs. Unlike AARs, DLRs are based not only on forecasted ambient air temperatures and the presence or absence of solar heating, but also on other weather conditions such as (but not limited to) wind, cloud cover, solar heating intensity (instead of mere daytime/nighttime distinctions used in AARs), and precipitation, and/or on transmission line conditions such as tension or sag. As discussed below, we adopt the NOPR's proposed definition of DLR as a transmission line rating that: (1) Applies to a time period of not greater than one hour; and (2) 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.

8. Although some transmission owners have adopted the use of DLRs for individual transmission lines, there is not currently widespread use of DLRs. While DLRs can represent more accurate transmission line ratings than AARs, based on the record in this proceeding, we decline to mandate DLR implementation in this final rule. We instead incorporate the record in this proceeding on DLRs into new Docket No. AD22–5–000, which we open to further explore DLR implementation.

9. One factor that may contribute to the limited deployment of DLRs by transmission owners is that the RTOs/ISOs that operate a large portion of the transmission system in the United States and oversee organized wholesale electric markets may not be able to automatically incorporate frequently updated transmission line ratings such as DLRs into their operating and market models. Although the record does not support a mandate for DLR implementation at this time, we require RTOs/ISOs to establish and maintain the systems and procedures necessary to allow transmission owners in their regions to electronically update transmission line ratings on at least an hourly basis.

10. In addition to reforms to improve the accuracy of transmission line ratings used during normal (pre-contingency) operations,[10] we revise the *pro forma*

[5] Federal Energy Regulatory Commission, Staff Paper, *Managing Transmission Line Ratings,* Docket No. AD19–15–000 (Aug. 2019) (Commission Staff Paper), *https://www.ferc.gov/sites/default/files/2020-05/tran-line-ratings.pdf.*

[6] 18 CFR 35.28(b)(10) (2021); *Pro Forma* OATT attach. M, AAR Definition.

[7] The term ''seam'' is commonly used by the industry to indicate the border between two transmission provider's service territories. Service at the seam can take different forms, such as point-to-point service or market-to-market service.

[8] The use of seasonal line ratings for long-term requests for transmission service and as the basis for the determination of curtailment, interruption, or redispatch is currently standard practice. However, as discussed below, we adopt certain reforms to change seasonal line rating implementation.

[9] Because the new requirements related to AARs and seasonal line ratings are implemented through the new *pro forma* OATT Attachment M, these requirements are placed upon *transmission providers.* However, we recognize that *transmission owners* (not transmission providers) determine transmission line ratings. In many instances, the transmission provider and transmission owner are the same entity. However, below in Section IV.B.2.b, we discuss compliance within RTOs/ISOs, where the transmission provider and transmission owner are separate entities.

[10] The North American Electric Reliability Corporation (NERC) Glossary defines ''normal

Continued

OATT to require transmission providers to use uniquely determined emergency ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints.[11] Such uniquely determined emergency ratings must also incorporate an adjustment for ambient air temperature and daytime/nighttime solar heating, consistent with our AAR requirements for normal ratings. Most transmission equipment can withstand high currents for short periods of time without sustaining damage. Emergency ratings reflect this technical capability, defining the specific additional current that a transmission line can withstand and for what duration the transmission line can withstand that additional current without sustaining damage. Because emergency ratings reflect this capability, uniquely determined emergency ratings will ensure more accurate transmission line ratings.

11. Finally, we adopt four requirements to enhance transparency. First, we require public utility transmission owners to share transmission line ratings and methodologies with their transmission provider(s) and with market monitors in RTOs/ISOs. Second, we require transmission providers to share their transmission owners' transmission line ratings and methodologies with any transmission provider(s) upon request. Third, we require transmission providers to maintain a database of their transmission owners' transmission line ratings and methodologies on the transmission provider's Open Access Same-Time Information System (OASIS) site or another password-protected website. Fourth, we require transmission providers to post on OASIS or another password-protected website any uses of exceptions or temporary alternate ratings. Availability of this additional information on transmission line ratings and their methodologies will facilitate more cost-effective decisions by transmission customers and more accurate transmission line ratings. We find that these transparency reforms will ensure that prices reflect the true cost of the wholesale service being provided and thereby are necessary to ensure just and reasonable wholesale rates.

12. We require each transmission provider to submit a compliance filing within 120 days of the effective date of this final rule revising their OATT to incorporate *pro forma* OATT Attachment M. We further require that all requirements adopted herein be fully implemented no later than three years from the compliance filing due date.

II. Background

13. In August 2019, Commission staff issued a paper entitled ''Managing Transmission Line Ratings,'' which drew upon Commission staff outreach conducted in spring 2019 with RTOs/ISOs, transmission owners, and trade groups, as well as staff participation in a November 2017 Idaho National Laboratory workshop. The report included background on common transmission line rating approaches, current practices in RTOs/ISOs, a review of pilot projects, and a discussion of potential improvements.[12]

14. On September 10 and 11, 2019, Commission staff convened a technical conference (September 2019 Technical Conference) to discuss what transmission line ratings and related practices might constitute best practices, and what, if any, Commission action in these areas might be appropriate. In particular, the September 2019 Technical Conference covered issues such as: (1) Common transmission line rating methodologies; (2) AAR and DLR implementation benefits and challenges; (3) the ability of RTOs/ISOs to accept and use DLRs; and (4) the transparency of transmission line rating methodologies.[13]

15. In October 2019, the Commission requested comments on questions that arose from the September 2019 Technical Conference.[14] In response, commenters addressed issues related to AARs and DLRs, emergency ratings, and transparency, as discussed below.

16. On November 19, 2020, the Commission issued the NOPR in this proceeding, proposing to amend the *pro forma* OATT and its regulations under the FPA to improve the accuracy and transparency of transmission line ratings.[15] Specifically, the Commission proposed a new *pro forma* OATT Attachment M ''Transmission Line Ratings'' to require transmission providers to implement AARs on the transmission lines over which they provide transmission service. The Commission also proposed revisions to its regulations to require RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly and to require transmission owners to share transmission line ratings and transmission line rating methodologies with their transmission provider(s) and, in RTOs/ISOs, with their market monitor(s). The Commission received comments from 56 entities on the NOPR proposals from a diverse set of stakeholders.[16]

III. Need for Reform

A. NOPR Proposal

17. In the NOPR, the Commission preliminarily found that transmission line ratings and the rules by which they are established are practices that directly affect the cost of wholesale energy, capacity, and ancillary services, as well as the cost of delivering wholesale energy to transmission customers. The Commission explained that, because of the relationship between transmission line ratings and costs, inaccurate transmission line ratings may result in Commission-jurisdictional rates that are unjust and unreasonable.[17]

18. The Commission explained that most transmission owners implement seasonal or static transmission line rating methodologies based on conservative, worst-case assumptions, such as high temperatures that are likely to occur over the longer term, but that often do not reflect the true near-term transfer capability of transmission facilities. Thus, the Commission reasoned, seasonal and static line ratings fail to reflect the true cost of delivering wholesale energy to transmission customers, and incorporating near-term forecasts of ambient air temperatures in transmission line ratings would more accurately reflect the actual cost of delivering wholesale energy to transmission customers.[18]

19. Because actual ambient air temperatures are usually not as high as the ambient air temperatures conservatively assumed in seasonal and static line ratings, the Commission

rating'' as: ''[t]he rating as defined by the equipment owner that specifies the level of electrical loading . . . that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[11] As discussed below in Section IV.F.2.b, uniquely determined means the ratings are determined based on assumptions that reflect the specific, finite duration of emergency ratings, as opposed to using assumptions used to calculate normal ratings.

[12] Commission Staff Paper, *https://www.ferc.gov/sites/default/files/2020-05/tran-line-ratings.pdf.*

[13] Supplemental Notice of Technical Conference, Docket No. AD19–15–000 (Sep. 4, 2019).

[14] Notice Inviting Post-Technical Conference Comments, Docket No. AD19–15–000 (Oct. 2, 2019).

[15] *Managing Transmission Line Ratings,* Notice of Proposed Rulemaking, 86 FR 6420 (Jan. 21, 2021), 173 FERC ¶ 61,165 (2020) (NOPR).

[16] *See* Appendix A for a list of entities that submitted comments and the shortened names used throughout this final rule to describe those entities.

[17] NOPR, 173 FERC ¶ 61,165 at P 38.

[18] *Id.* P 39.

observed that updating transmission line ratings used in near-term transmission service to reflect actual ambient air temperatures usually results in increased system transfer capability and, in turn, lower costs for consumers. However, the Commission also observed that seasonal and static line ratings can at times assume temperatures that are lower than the actual ambient air temperatures in the short term. In doing so, the Commission noted that seasonal or static transmission line rating methodologies can at times result in transmission line ratings that reflect more transfer capability than physically exists. The Commission observed that this overstatement of transmission line ratings similarly results in wholesale energy rates that fail to reflect the actual cost of delivering wholesale energy to transmission customers, and may also create reliability and safety problems, risk damage to equipment, and prevent occurrences of rates for scarcity pricing or transmission constraint penalty factors.[19]

20. Regarding DLR implementation, the Commission observed that some RTOs/ISOs may rely on software and systems that cannot accommodate transmission line ratings that frequently change, such as DLRs, and that, without reflecting such frequent changes to transmission line ratings, such software may serve as a barrier that prevents transmission owners in RTOs/ISOs from implementing DLRs, which can better reflect the actual transfer capability of the transmission system. The Commission explained that, in addition to ambient air temperature, DLRs incorporate additional inputs, including wind, cloud cover, solar heating, and precipitation, as well as transmission line conditions such as tension and sag. DLRs thereby provide transmission line ratings that are closer to the true thermal transmission line limit than AARs, which can result in rates that even more accurately reflect the costs of delivering wholesale energy to transmission customers than relying on AARs. However, the Commission explained that the potential inability of RTOs/ISOs to automatically accept and use DLRs provided by transmission owners may prevent RTO/ISO markets from benefiting from the more accurate representation of current RTO/ISO system conditions. In turn, by ensuring RTO/ISO market models can incorporate more accurate representations of system conditions when transmission owners use DLRs, RTO/ISO markets would produce prices that more accurately reflect the costs of delivering wholesale energy to transmission customers. For this reason, the Commission also preliminarily found in the NOPR that current transmission line rating practices in RTOs/ISOs that do not permit the acceptance of DLRs from transmission owners may result in rates that do not reflect the actual costs of delivering wholesale energy to transmission customers.[20]

21. Regarding emergency ratings, the Commission found that current transmission line rating practices may fail to use emergency ratings, and in failing to do so, may result in transmission line ratings that do not accurately reflect the near-term transfer capability of the system. This, in turn, may result in rates that do not reflect actual costs of delivering wholesale energy to transmission customers. In support, the Commission stated that transmission owners often develop two sets of transmission line ratings for most facilities: Normal ratings that can be safely used continuously, and emergency ratings that can be used for a specified shorter period of time, typically during post-contingency operations. Because emergency ratings are a more accurate representation of the flow limits over shorter timeframes, the Commission preliminarily found that their use in models of post-contingency flows may produce prices that more accurately reflect actual costs of delivering wholesale energy to transmission customers.[21]

22. Finally, in the NOPR, the Commission preliminarily found that, by preventing transmission providers and, in RTO/ISOs, market monitors from having the opportunity to validate transmission line ratings in situations where a transmission provider serves any transmission owners that are not itself, current levels of transparency into transmission line ratings and transmission line rating methodologies may result in unjust and unreasonable rates. The Commission observed that a consequence of a lack of transparency could be inaccurate near-term transmission line ratings, which may result in rates that do not accurately reflect congestion and reserve costs on the system. As one example, the Commission stated that, without knowing the basis for a given transmission line rating that frequently binds and elevates prices, a transmission provider and/or market monitor cannot determine whether the transmission line rating is accurately calculated and therefore whether unjust and unreasonable wholesale rates are being created through use of inaccurate transmission line ratings.[22]

B. Comments

23. Commenters overwhelmingly agree with the Commission's preliminary finding that transmission line ratings and the rules by which they are established are practices that directly affect the cost of wholesale energy, capacity, and ancillary services, as well as the cost of delivering wholesale energy to transmission customers.[23] Commenters also agree with the Commission's preliminary finding that, because of the relationship between transmission line ratings and wholesale energy costs, inaccurate transmission line ratings may result in Commission-jurisdictional rates that are unjust and unreasonable.[24]

24. The majority of commenters representing state agencies support the Commission's basis for reform. New England State Agencies explain that, because transmission lines are used to control the amount of energy on electric power systems, transmission line ratings affect the price of electric power as well as the reliability of the electric grid.[25] OMS also agrees with the Commission's preliminary finding that transmission line ratings directly affect wholesale energy costs and artificially limit transfers within and between regions, stating that such a conclusion is obvious and correct.[26] OMS further contends that the slow pace of action on this issue by RTOs/ISOs and transmission owners makes the issue ripe for Commission action.[27] Ohio FEA maintains that transmission line ratings have a direct and significant influence on wholesale energy and capacity markets and, therefore, must be accurate. Ohio FEA further argues that inaccurate transmission line ratings may also cause Locational Deliverability Areas (LDAs) to unnecessarily constrain in the

[19] *Id.* P 42.

[20] *Id.* P 43.

[21] *Id.* PP 44–46.

[22] *Id.* P 47.

[23] AEP Comments at 3; Ohio FEA Comments at 6; New England State Agencies Comments at 8; OMS Comments at 6; Potomac Economics Comments at 5; CAISO DMM Comments at 4; SPP MMU Comments at 1–2; R Street Institute Comments at 2; Industrial Customer Organizations Comments at 11–12; TAPS Comments at 5–6; WATT Comments at 3–5; Certain TDU Comments at 4–5; Clean Energy Parties Comments at 2–3; EDFR Comments at 3.

[24] SPP MMU Comments at 1–2; Potomac Economics Comments at 5; CAISO DMM Comments at 4; Industrial Customer Organizations Comments at 11–12; TAPS Comments at 5–6; Certain TDU Comments at 4–5; Clean Energy Parties Comments at 2–3.

[25] New England State Agencies Comments at 8.

[26] OMS Comments at 6.

[27] OMS Reply Comments at 2–3.

capacity market, resulting in higher capacity prices.[28]

25. Each of the commenting market monitors supports the Commission's basis for reform. For example, Potomac Economics agrees with the Commission's finding that inaccurate transmission line ratings may result in rates that are not just and reasonable and notes that facility ratings are used in virtually every aspect of electricity markets and system operations. Potomac Economics further avers that transmission line ratings determine the transmission limits input into market models, which, in turn, determine the commitment and dispatch needed to satisfy load and manage congestion. Potomac Economics further explains that underestimated transmission line ratings cause inefficient operations, higher congestion, reduced transmission availability, higher costs, higher renewable energy curtailments, and a greater perceived need for new transmission facilities.[29] The SPP MMU also agrees with the Commission's assertion that transmission line ratings can directly affect the cost of producing wholesale energy, capacity, and ancillary services, as well as the cost of delivering such products. The SPP MMU explains that the cost of congestion is directly impacted by transmission line ratings and that inaccurate transmission line ratings cause price distortions, which may result in unjust and unreasonable rates.[30] The CAISO DMM also agrees with the Commission's assessment that transmission line ratings and the rules by which they are established directly impact the cost of wholesale energy delivery and related services, explaining that static or seasonal line ratings can lead to increased costs when their assumptions are not realized, which may be inefficient and can result in excess cost paid by load.[31]

26. Other commenters also support the Commission's basis for reform. R Street Institute states that the Commission's problem statement is sound, explaining that transmission line ratings are chronically understated because they do not reflect current weather conditions, and as a result, according to R Street Institute, fail to allow for significant cost savings.[32] Industrial Customer Organizations state that transmission line ratings and associated rules directly affect the cost of wholesale energy, capacity, and ancillary services, and the cost of delivering wholesale energy to transmission customers, and the rulemaking is therefore consistent with the Commission's authority and obligations under the FPA.[33] TAPS states that reliance on static or seasonal line ratings inflicts unnecessary costs on consumers and that AAR deployment can provide significant benefits to consumers.[34] WATT explains that accurate transmission line ratings lower costs for consumers.[35] Certain TDUs assert that enhanced transmission line ratings, including AARs and DLRs, are tools that maximize the efficiency of the existing transmission system and lower costs for consumers.[36]

27. Finally, clean energy and generator representatives also support the Commission's basis for reform.[37] For example, Clean Energy Parties conclude that, due to the impact that transmission line ratings have on wholesale rates requirements, accurate transmission line ratings are consistent with the Commission's mandate under sections 205 and 206 of the FPA.[38]

28. However, NYTOs question the Commission's legal standing to regulate transmission line ratings, noting that the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) found that there are limits to the Commission's FPA section 206 jurisdiction over ''practices'' and that the term may not include all utility operations.[39] NYTOs note that the Commission's authority to regulate transmission planning was upheld on appeal but that Order No. 1000 [40] is not prescriptive; therefore, NYTOs request that the Commission similarly allow utilities to make their own decisions related to advanced line rating technologies.[41]

C. Commission Determination

29. We find 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''). Thus, the Commission has jurisdiction over transmission line ratings.[42] We further find 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. Accordingly, pursuant to FPA section 206,[43] we conclude that certain revisions to the *pro forma* OATT and the Commission's regulations are necessary to ensure just and reasonable wholesale rates. We adopt most of the reforms proposed in the NOPR, with certain clarifications, as discussed further herein, and revisions to the proposed *pro forma* OATT Attachment M and to the Commission's regulations.

30. We find that transmission line ratings directly affect wholesale rates because transmission line ratings and wholesale rates are inextricably linked. As explained above, transmission line ratings represent the maximum transfer capability of each transmission line. That transfer capability determines the quantity of energy that can be transmitted from suppliers to load in any given moment. Supply and demand fundamentals dictate that less transfer capability (*i.e.,* less supply) will result in higher rates, all else being equal. Inaccurate transmission line ratings can result in underutilization (or overutilization) of existing transmission facilities, thereby sending a signal that there is less (or more) transfer capability than is truly available. This signal impacts the wholesale rates charged for providing energy and other ancillary services. For example, if the system operator believes there is less transfer capability than is truly available, it may dispatch more expensive generators to serve load, when less expensive generators (which would have resulted in lower congestion costs) could have been used to reliably serve the same load. Alternatively, inaccurate transmission line ratings can result in oversubscription of existing transmission facilities, thereby sending the opposite signal—that there is more transfer capability than is truly available—which may risk damage to equipment, may fail to accurately price congestion costs, and may fail to signal to the market that more generation and/or transmission investment may be needed in the long term. We therefore find that transmission line ratings

[28] Ohio FEA Comments at 6.

[29] Potomac Economics Comments at 5.

[30] SPP MMU Comments at 1–2.

[31] CAISO DMM Comments at 4.

[32] R Street Institute Comments at 2.

[33] Industrial Customer Organizations Comments at 11–12.

[34] TAPS Comments at 5–6.

[35] WATT Comments at 3–5.

[36] Certain TDUs Comments at 4.

[37] Clean Energy Parties Comments at 2–3; EDFR Comments at 3.

[38] Clean Energy Parties Comments at 2–3.

[39] NYTOs Comments at 9 (referencing *Cal. Indep. Sys. Operator Corp.* v. *FERC,* 372 F.3d 395, 402 (D.C. Cir. 2004)).

[40] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 77 FR 32184 (May 31, 2012), 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh'g and clarification,* Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[41] NYTOs Comments at 9–10.

[42] 16 U.S.C. 824(b)(1), 824d.

[43] 16 U.S.C. 824e.

directly affect wholesale rates and, concomitantly, that inaccurate transmission line ratings result in unjust and unreasonable wholesale rates.[44]

31. Most commenters, except NYTOs, agree with the Commission's preliminary conclusion that transmission line ratings directly affect wholesale rates.[45] NYTOs caution that the D.C. Circuit found there are limits to the Commission's FPA section 206 jurisdiction over ''practices'' and that the term may not include all utility operations.[46] But, the inextricable link between transmission line ratings and wholesale rates places transmission line ratings within the Commission's FPA section 206 jurisdiction.

32. Some commenters, in response to the preliminary finding that accurate transmission line ratings are necessary for just and reasonable wholesale rates, argue that transmission line ratings are fundamentally a reliability tool.[47] We agree that system safety and reliability are paramount to the proposed requirements for transmission line ratings. But we disagree with the suggestion that because transmission line ratings are critical to reliability, economic considerations are an inappropriate basis for requiring a certain type of transmission line ratings. Instead, we find that commenters present a false choice; economic considerations and reliability considerations are inextricably linked as reliability constraints bound the potential economic transactions of market participants. In the case of transmission line ratings, transmission owners calculate the maximum transfer capability of a transmission line. Transmission providers, in order to maintain reliable system operations, incorporate those ratings and other constraints into operations, and the results determine dispatch and commitment instructions and wholesale rates. Even though transmission line ratings can be seen as a reliability tool, that does not obviate the need to ensure that the wholesale rates resulting from such reliability tools are just and reasonable.

33. Regarding that incorporation of transmission line ratings into operations and resulting wholesale rates, as the Commission explained in the NOPR, most transmission owners implement seasonal or static line ratings. Such seasonal or static line ratings are based on conservative, worst-case assumptions about long-term conditions, such as the expected high temperatures that are likely to occur over the longer term. While such long-term assumptions may be appropriate in various planning contexts, they often do not reflect the true near-term transfer capability of transmission facilities and, when used in near-term operations, produce unjust and unreasonable wholesale rates.

34. As explained in the NOPR, incorporating near-term forecasts of ambient air temperatures in transmission line ratings can more accurately reflect the true near-term transfer capability of transmission facilities than continuing to rely on seasonal or static line ratings. Because actual ambient air temperatures are usually not as high as the ambient air temperatures conservatively assumed in seasonal and static line ratings, updating the transmission line ratings used in near-term transmission service to reflect actual ambient air temperatures usually results in increased system transfer capability. By increasing transfer capability, congestion costs will, on average, decline because transmission providers will be able to serve load with less expensive resources from what were previously constrained areas. For example, Potomac Economics has found that AAR implementation by those not already using AARs in MISO alone would have produced approximately $66.5 million and $49 million in reduced congestion costs in 2019 and in 2020, respectively.[48] 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 of the wholesale service being provided. Likewise, the ability to increase transmission flows into load pockets may reduce transmission provider reliance on local reserves inside load pockets, which may reduce local reserve requirements and the costs to maintain that required level of reserves.

35. Moreover, while current transmission line rating practices usually understate transfer capability, they can also overstate transfer capability and, in doing so, place transmission lines at risk of inadvertent overload. While actual ambient air temperatures are usually not as high as the assumed seasonal or static line rating temperature input, in some instances actual ambient air temperatures exceed those assumed temperatures. In those instances, seasonal or static line ratings might reflect more transfer capability than physically exists, and therefore such transmission line ratings might allow access to some electric power supplies and/or demand that would not be available if transmission line ratings reflected the true transfer capability. Overstating transfer capability, like understating transfer capability, can result in wholesale rates that fail to reflect the cost of the wholesale service being provided, though, in the case of overstated transfer capability, through inaccurately low congestion pricing and failing to signal to the market that more generation and/or transmission investment may be needed in the long term.

36. Regarding DLRs, in addition to ambient air temperatures and the presence or absence of solar heating, other weather conditions such as (but not limited to) wind, cloud cover, solar heating intensity, and precipitation, and transmission line conditions such as tension and sag, can affect the amount of transfer capability of a given transmission facility. DLRs incorporate these additional inputs and thereby provide transmission line ratings that are closer to the true thermal transmission line limits than AARs. However, as noted above and explained in greater detail in Section IV.E below, based on the record in this proceeding, we decline to mandate DLR implementation in this final rule. We instead incorporate the record in this proceeding on DLRs into new Docket No. AD22–5–000, which we open to further explore DLR implementation.

37. While we believe additional record is needed regarding DLR implementation, we can determine based on the record that current transmission line rating practices in RTOs/ISOs that do not permit the acceptance of DLRs from transmission owners that use DLRs are contributing to unjust and unreasonable wholesale rates by acting as a barrier to accurate transmission line ratings. Therefore, as part of remedying inaccurate transmission line ratings that result in unjust and unreasonable wholesale rates, we require RTOs/ISOs to establish and maintain the systems and

[44] SPP MMU Comments at 1–2; Potomac Economics Comments at 5; CAISO DMM Comments at 4; Industrial Customer Organizations Comments at 11–12; TAPS Comments at 5–6; Certain TDU Comments at 4–5; Clean Energy Parties Comments at 2–3.

[45] AEP Comments at 3; Ohio FEA Comments at 6; New England State Agencies Comments at 8; OMS Comments at 6; Potomac Economics Comments at 5; CAISO DMM Comments at 4; SPP MMU Comments at 1–2; R Street Institute Comments at 2; Industrial Customer Organizations Comments at 11–12; TAPS Comments at 5–6; WATT Comments at 3–5; Certain TDU Comments at 4–5; Clean Energy Parties Comments at 2–3; EDFR Comments at 3.

[46] NYTOs Comments at 9–10.

[47] *See, e.g.,* Dominion Comments at 13; Exelon Comments at 6; PJM Indicated Transmission Owners Comments at 2; EEI Comments at 5.

[48] Potomac Economics Comments at 8.

procedures necessary to permit the acceptance of DLRs from transmission owners that use them. As the Commission explained in the NOPR, some RTOs/ISOs rely on software that cannot accommodate transmission line ratings that frequently change, such as DLRs.[49] Without reflecting such frequent changes to transmission line ratings, such software serves as a barrier that prevents transmission owners in RTOs/ISOs from implementing DLRs and better reflecting the actual transfer capability of the transmission system. The result is that, even if a transmission owner sought to implement DLRs, the RTO's/ISO's energy management system (EMS) may not be able to accept and use the resulting transmission line rating. The potential inability of RTOs/ISOs to accept and use a DLR prevents RTO/ISO markets from benefiting from the more accurate representation of current system conditions. Therefore, we require RTOs/ISOs to establish and maintain the systems and procedures necessary to permit the acceptance of DLRs from transmission owners that use them.

38. Regarding emergency ratings, we find that many transmission owners' current transmission line rating practices fail to use emergency ratings, and in failing to do so, lead to transmission line ratings that do not accurately reflect the near-term transfer capability of the transmission system, and therefore result in wholesale rates that do not reflect costs of the wholesale service being provided. As the Commission explained in the NOPR, transmission owners often develop two sets of transmission line ratings for most facilities: Normal ratings that can be safely used continuously, and emergency ratings that can be used for a specified shorter period of time, typically during post-contingency operations. Transmission providers generally calculate resource dispatch and commitments to ensure that all facilities are within applicable facility ratings both during normal operations and following any modeled contingency (*e.g.,* following the loss of a transmission line). In ensuring that the system is stable and reliable following a contingency, transmission providers often allow post-contingency flows on transmission lines to exceed normal ratings for short periods of time, as long as those flows do not exceed the applicable emergency rating for the corresponding timeframe. Because these emergency ratings are a more accurate representation of the flow limits over those shorter timeframes, their use in models of post-contingency flows produces wholesale rates that more accurately reflect the costs of the wholesale service being provided and therefore is necessary to ensure just and reasonable wholesale rates. For this reason, as described below, we require that transmission providers implement uniquely determined emergency ratings. Additionally, we require that transmission providers use uniquely determined emergency ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints. Such uniquely determined emergency ratings must also include separate AAR calculations for each emergency rating duration used.

39. Finally, we find that the current level of transparency into transmission line ratings and methodologies may result in unjust and unreasonable wholesale rates. In some regions, where the transmission owner and transmission provider are not the same entity, such as RTOs/ISOs, current transparency levels prevent the transmission provider and market monitor(s) from having the opportunity to assess the accuracy of transmission line ratings. For example, as the Commission described in the NOPR, without knowing the basis for a given transmission line rating that frequently binds and elevates prices, a transmission provider and/or market monitor cannot determine whether the transmission line rating is accurately calculated.[50] Moreover, we find that, absent additional information to market participants on transmission line ratings and their methodologies, the status quo does not provide market participants with information important to making cost-effective decisions and, thereby, impedes such decisions. For example, without accurate transmission line rating information, market participants operate without information that is important in making accurate economic decisions regarding where to build generation or where to site load. Further, this lack of transparency could allow transmission owners to submit inaccurate near-term transmission line ratings, which, in turn, would result in wholesale rates that do not accurately reflect the cost of the wholesale service being provided, as discussed above. For these reasons, we require: (1) Public utility transmission owners to share transmission line ratings and methodologies with their transmission provider(s) and with market monitors in RTOs/ISOs; (2) transmission providers to share their transmission owners' transmission line ratings and methodologies with any transmission provider(s) upon request; (3) transmission providers to maintain a database of their transmission owners' transmission line ratings and methodologies on the transmission provider's OASIS site or another password-protected website; and (4) transmission providers to post on OASIS or another password-protected website any uses of exceptions or temporary alternate ratings.

IV. Discussion

A. Transmission Line Ratings Definition

1. NOPR Proposal

40. In the NOPR, the Commission proposed to define a transmission line rating in *pro forma* OATT Attachment M as the maximum transfer capability of a transmission line, computed in accordance with a written transmission line rating methodology and consistent with good utility practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the transmission system (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.[51]

41. Under the ''Obligations of Transmission Provider'' section in *pro forma* OATT Attachment M, the Commission further proposed to require that the transmission provider must use either AARs or seasonal line ratings, as appropriate, as the relevant transmission line ratings. Similarly, and as described in more detail in Section IV.D.3, the Commission proposed exceptions to the AAR and seasonal line rating requirements for certain transmission line ratings.

2. Comments

42. Some commenters support the proposed definition of transmission line rating, while others request clarity or modifications be made, specifically around the list of relevant transmission equipment. AEP supports the Commission's proposed transmission line rating definition, explaining that the Commission's proposed definition reflects the fact that transmission line ratings incorporate a set of electrical equipment that collectively operate as a single bulk electric system element (*e.g.,* transformers, relay protective devices, terminal equipment, and series and shunt compensation devices) and that the most limiting component from that

[49] NOPR, 173 FERC ¶ 61,165 at P 43.

[50] *Id.* P 47.

[51] NOPR, 173 FERC ¶ 61,165 at P 85.

set determines the transmission line rating.[52] Similarly, Indicated PJM Transmission Owners address the NOPR's proposed AAR requirements set forth in *pro forma* OATT Attachment M under ''Obligations of Transmission Provider'' (hereinafter referred to as ''the proposed AAR requirements'') as ambient-adjusted and seasonal line ratings, consistent with NERC's definition of facility rating,[53] and describe Indicated PJM Transmission Owners' implementation of AARs, consistent with NERC's definition of facility ratings.[54] PJM also describes the implementation of AARs for each of its transmission facilities.[55]

43. Entergy explains that overhead conductor ratings and ratings for ''ancillary equipment,'' or equipment that does not include a primary element, like conductors and transformers, can be temperature adjusted. According to Entergy, examples of ''ancillary equipment'' include breakers, switches, traps, busses, jumpers, current transformers, potential transformers, and relay equipment. Entergy further asserts, however, that shunt reactors, series capacitors, relays, current transformers, static VAR compensators, circuit breakers, autotransformers, copper weld (''CW'') buses, conductors, risers or jumpers, and, subject to limited exceptions, customer equipment have ratings that cannot be temperature adjusted.[56] Eversource states that the ratings for relays and other equipment, such as splices, switches, and terminal equipment, are not impacted by ambient air temperatures.[57] NYISO states that the majority of the bulk electric system equipment ratings in New York are able to be rated using AARs or DLRs,[58] while NYTOs note that transmission line ratings may be based on non-conductor components which are not affected by ambient air temperatures.[59] EEI and MISO Transmission Owners request clarity on the definition of transmission line rating and its specific applicability, stating that the AAR requirements should not apply to power transformers, but instead, under certain circumstances, to other types of transformers, including current transformers.[60] EEI further explains that ratings for power transformers are generally the result of the efficiency of the heat transfer process, not ambient air temperatures directly, and thus requests that the Commission clarify that the references to transformers apply only to transformers that limit or impact transmission line ratings and not power transformers generally.[61] Entergy similarly notes that transformer and relay ratings do not change with ambient conditions.[62] ITC states that AARs cannot be applied to voltage or stability limits and therefore recommends that ''transmission line rating'' reflect the concepts of equipment and facility rating as defined by NERC in order to avoid confusion with a system operating limit.[63] APS states that transmission lines with limitations associated with substation equipment or series capacitors, among other equipment in which the transmission line is not the limiting factor, may not experience changes to their transfer capabilities.[64] MISO contends that the list could include potential relay trip limits and maximum power transfer limits.[65]

3. Commission Determination

44. In this final rule, we adopt the definition of transmission line rating proposed in the NOPR. Specifically, we adopt the proposed definition that a transmission line rating means the maximum transfer capability of a transmission line, computed in accordance with a written transmission line rating methodology and consistent with good utility practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the transmission system (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers. As the Commission stated in the NOPR, system safety and reliability are paramount to the proposed requirements for transmission line ratings. We agree with AEP that the definition adopted herein reflects the fact that transmission line ratings must incorporate a set of electrical equipment ratings that collectively operate as a single bulk electric system element (*e.g.,* transformers, relay protective devices, terminal equipment, and series and shunt compensation devices) and that the most limiting component from that set determines the transmission line rating.[66]

45. In response to comments about the definition's inclusion of the technical limitations (such as thermal flow limits) on conductors and relevant transmission equipment, we clarify that the definition of transmission line rating encompasses transmission line ratings for electric system equipment that includes more than just overhead conductors. For example, it includes ratings for electric system equipment such as circuit breakers, line traps, and transformers. Additionally, as described in more detail below in Section IV.D.3, we adopt the list of proposed exceptions from the NOPR. Consequently, we do not require transmission line ratings that are not affected by ambient air temperatures to be rated using forecasts of ambient air temperatures. That said, we decline to define in this final rule which electric system equipment ratings are (or are not) affected by ambient air temperatures. Instead, we allow flexibility for individual transmission owners and transmission providers to apply good utility practice to determine which specific electric system equipment has ratings that are (or are not) affected by ambient air temperatures.

46. Finally, in response to requests for clarification from EEI and MISO Transmission Owners regarding the applicability of the proposed AAR requirements to power transformers, we decline to provide a generic exception from the AAR requirement for power transformers. The operating limits of a power transformer are bounded by the

[52] AEP Comments at 2–3.

[53] The NERC Glossary defines a ''Facility Rating'' as: ''[t]he maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[54] Indicated PJM Transmission Owners Comments at 1–2, 6–7.

[55] PJM Comments at 2–3.

[56] Entergy Comments at 5–6.

[57] Eversource Comments at 3.

[58] NYISO Comments at 3–4.

[59] NYTOs Comments at 8.

[60] EEI Comments at 17–18; MISO Transmission Owners Comments at 39–40.

[61] EEI Comments at 17–18.

[62] Entergy Comments at 9–10.

[63] ITC Comments at 11–12. The NERC Glossary defines an ''Equipment Rating'' as: ''[t]he maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.'' It defines a ''System Operating Limit'' as: ''[t]he value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings); transient stability ratings (applicable pre- and post-Contingency stability limits); voltage stability ratings (applicable pre- and post-Contingency voltage stability); and system voltage limits (applicable pre- and post-Contingency voltage limits).'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[64] APS Comments at 3.

[65] MISO Comments at 34.

[66] AEP Comments at 2–3.

ambient air temperature, the average winding temperature, and the maximum winding hottest-spot temperature.[67] However, we reiterate the exceptions adopted herein and discussed further below, which provide that any rating not affected by ambient air temperatures would not be required to incorporate forecasts of ambient air temperatures into the rating. Thus, if a transmission provider determines, consistent with good utility practice, that a specific power transformer's rating is not affected by ambient air temperature, then that power transformer would fall within the scope of such exceptions to the AAR requirement.

B. Ambient-Adjusted Ratings

1. AAR Definition and Transmission Provider Obligations

a. NOPR Proposal

47. In the NOPR, the Commission proposed to define an AAR in *pro forma* OATT Attachment M and in the Commission's regulations as a transmission line rating that: (1) Applies to a time period of not greater than one hour; (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; and (3) is calculated at least each hour, if not more frequently. As obligations of the transmission provider set forth in *pro forma* OATT Attachment M, the Commission proposed to require that transmission providers use AARs as the applicable line rating: (1) For requests for near-term point-to-point transmission service ending within 10 days of the request date, as defined in *pro forma* OATT Attachment M; (2) for determining the necessity of near-term curtailment or interruption of near-term point-to-point transmission service anticipated to occur (start and end) within the next 10 days; and (3) for determining the necessity of near-term interruption or redispatch of network transmission service anticipated to occur (start and end) within the next 10 days. The Commission proposed to require transmission providers to implement the use of AARs and seasonal line ratings on all historically congested transmission lines[68] within one year after the compliance filing due date and on all other transmission lines within two years after the compliance filing due date.[69] For RTOs/ISOs, for which the Commission has approved variations from the *pro forma* OATT to manage congestion and initiate curtailments and/or redispatch of transmission service within their footprints (although generally not at their borders), the Commission proposed two requirements. First, the Commission proposed requirements for RTOs/ISOs to implement AARs in both the day-ahead and real-time markets and any intra-day reliability unit commitment. Second, the Commission proposed to require AARs as the relevant transmission line rating for any near-term point-to-point transmission service offered (*e.g.,* at the RTO's/ISO's borders).

48. As justification for the NOPR proposal to require AAR implementation on all transmission lines and not only on historically congested lines, the Commission noted that any facility can become the most limiting element as the transmission system changes, and in certain circumstances flows may change considerably from normal operations. Therefore, the Commission proposed to require AARs be implemented on all transmission lines but recognized that a staggered implementation schedule would allow transmission providers and transmission owners to focus initial implementation where it would have the most impact.[70]

49. As justification for requiring AARs, the Commission preliminarily found that AAR requirements strike an appropriate balance between benefits and challenges. First, the Commission observed that, while there are differences across transmission systems, simply accounting for ambient air temperatures in transmission line ratings can reliably increase power transfer capability and significantly lower production costs at a manageable implementation cost. The Commission next explained that, according to Potomac Economics' estimates, the benefits to AAR implementation by those not already implementing AARs in MISO alone would have produced approximately $94 million and $78 million in reduced congestion costs in 2017 and in 2018, respectively. The Commission further explained that, while several entities noted implementation costs as a barrier to AAR implementation, the costs identified were mostly initial investments in upgraded OASIS and/or EMS and ratings databases and that once these systems are upgraded, adding AARs to additional transmission lines appears to have a minimal incremental cost.[71]

b. Comments

50. In response to the proposed AAR requirements, RTO/ISO comments are mixed, with most requesting flexibility to accommodate regional or market differences,[72] while market monitors are generally supportive of the NOPR proposal.[73] Transmission owners are conceptually supportive of AAR implementation but request flexibility in response to what they generally describe as an overly broad requirement.[74] The PJM transmission owners that submitted comments are generally supportive of the proposed AAR requirements in *pro forma* OATT Attachment M, explaining that they have experience using AARs.[75] Other commenters, including state governments, generation, load, renewable energy advocates, and other technical experts, are generally supportive of the proposed AAR requirements.[76]

51. Several transmission owners explain that they currently use AARs on all or parts of their transmission lines and support the Commission's NOPR proposal to implement widespread AAR use. AEP notes that it has used AARs in real-time operations for decades and that AARs have provided both reliability and financial benefits.[77] AEP notes that the use of AARs is common in PJM and that it similarly implements AARs for its facilities in SPP and the Electric Reliability Council of Texas (ERCOT).[78] Exelon states that it

[67] Institute of Electrical and Electronics Engineers, IEEE Standard for General Requirements for Liquid-Immersed Distribution, Power, and Regulating Transformers, IEEE Std C57.91.00–2021.

[68] The Commission proposed to define a historically congested transmission line as ''a transmission line that was congested at any time in the five years prior to the effective date of [this final rule].'' NOPR, 173 FERC ¶ 61,165 at P 92.

[69] *Id.* P 131.

[70] *Id.* PP 93–94.

[71] *Id.* P 99.

[72] *See, e.g.,* MISO Comments at 7, 9, 14–16; NYISO Comments at 9–11; ISO–NE Comments at 9.

[73] Potomac Economics Comments at 3–4; CAISO DMM Comments at 2–4; SPP MMU Comments at 1, 4.

[74] MISO Transmission Owners Comments at 8–9; PacifiCorp Comments at 2; EEI Comments at 2–5; NRECA/LPPC Comments at 2–3; Entergy Comments at 1–2; BPA Comments at 2–4; WAPA Comments at 4–5; APS Comments at 2–4; Southern Company Comments at 2–3; NYTOs Comments at 2–3; Duke Energy Comments at 1–2; PG&E Comments at 3; SCE Comments at 1–2; SDG&E Comments at 1–2; LADWP Comments at 2–3; IID Comments at 4–6; ITC Comments at 1–3; Sunflower Comments at 2; Eversource Comments at 5–7.

[75] Exelon Comments at 1–2; AEP Comments at 5–6; Dominion Comments at 3–4; Indicated PJM Transmission Owner Comments at 1–4.

[76] New England State Agencies Comments at 10; OMS Comments at 2; Ohio FEA Comments at 2; R Street Institute Comments at 1–2; WATT Comments at 1–2; DC Energy Comments at 1–2; ACORE Comments at 1; Clean Energy Parties Comments at 2, 4–6; ENEL Comments at 1; EDFR Comments at 1–2; Vistra Comments at 1–2; EPSA Comments at 2; Industrial Customers Comments at 1–2; TAPS Comments at 1–2; Certain TDU Comments at 1.

[77] AEP Comments at 3.

[78] *Id.* at 3–4.

considers AARs to be a best practice, explaining that all of its six utilities have implemented AARs on their transmission systems, without any adverse reliability or safety impacts, and have found the practice to be a cost-effective tool to enhance grid reliability.[79] Dominion states that, because PJM has implemented AARs for transmission service and for use in its day-ahead and real-time markets, Dominion Energy Virginia has adopted and uses PJM's AAR methodology on all its transmission lines, while Dominion Energy South Carolina uses AARs on only a portion of its transmission system.[80] Indicated PJM Transmission Owners support efforts to enhance transmission utilization by requiring AAR and seasonal line rating implementation, explaining that such practices improve efficiency; they also state that transmission line ratings are fundamentally a reliability tool.[81] While generally supportive of the NOPR proposal, Dominion, AEP, and Indicated PJM Transmission Owners all request flexibility to accommodate PJM's current AAR implementation and ask that the Commission not require hourly updates to AARs.[82]

52. Both ITC and Sunflower state that they are generally supportive of AAR implementation, but urge flexibility for transmission providers to implement AARs.[83] MISO Transmission Owners, explaining that they have initiated a process to implement AARs, state that they support certain aspects of the NOPR, but also state that other aspects are overly broad and will not yield sufficient benefits to justify the costs.[84] MISO Transmission Owners urge the Commission to allow for regional flexibility in any requirements and state that AAR deployment should focus on where it is expected to provide benefits by ''freeing up'' additional transfer capability.[85] MISO Transmission Owners state that, over the past five years, congestion arose on only 10% of the nearly 10,000 transmission facilities under MISO's functional control and that there would be no benefit to implementing AARs on non-congested lines.[86] MISO Transmission Owners also state that there are several necessary steps to implement AARs, which can be costly and time consuming.[87] Additionally, MISO Transmission Owners state that the Commission should not rely upon Potomac Economics' estimates of AAR benefits, explaining that Potomac Economics inaccurately assumed that: (1) All transmission lines are ambient adjustable; (2) all transmission owners are using worst-case assumptions; and (3) congestion caused by transient outages existed even though it has since been alleviated by recent upgrades.[88]

53. NYTOs, Eversource, and Southern Company request that the Commission refrain from adopting blanket AAR requirements for all transmission lines and instead require transmission providers to adopt a process for determining whether to apply AARs or DLRs to certain transmission facilities.[89] Southern Company suggests that such a process could be similar to the Commission's available transfer capability (ATC) requirements, whereby a public utility could include the metrics and criteria for determining when to use AAR or DLR in its OATT and implementation details in its guidelines or business practices.[90] Southern Company states that, while broader use of AARs and DLRs may provide cost savings to customers, the Commission's proposed approach in the NOPR is overly prescriptive and may therefore create unnecessary implementation complications and limit the deployment of other grid-enhancing technologies.[91] Southern Company and NRECA/LPPC also argue that non-RTO/ISO regions are characterized by long-term transmission commitments and that incremental short-term transfer capability is less relevant and less likely to result in cost savings.[92] Eversource contends that it applies AARs where it is beneficial, but states that the benefits of AARs will depend on specific circumstances within a region, noting that there is little congestion in ISO–NE.[93]

54. Southern Company states that reliability issues may arise as a result of the NOPR proposal because AARs may create difficulties in identifying the most limiting element, which may change as the temperature changes, and similar difficulties may arise in complying with Reliability Standard PRC–023–4's transmission relay loadability requirements that depend on maximum published ratings.[94] EEI states that, to ensure compliance with Reliability Standard PRC–023–4, significant amounts of field engineering time could be required to install and test new settings for thousands of relays.[95] NYTOs state that implementing the AAR requirements will require significant time and resources and would divert scarce resources from ongoing efforts to meet the goals of New York's Climate Leadership and Community Protection Act.[96] NERC contends that the Commission should keep in mind considerations for implementing AARs across long transmission lines that span multiple climates.[97]

55. Duke Energy states that it already employs AARs in real-time operations and supports the Commission's proposed requirements for transmission providers to implement AARs in real-time operations.[98] However, Duke Energy also argues that, because incorporating AARs into ATC calculations would require fundamental software changes that may take several million dollars and multiple years to complete, the benefits may not outweigh the costs.[99] Duke Energy suggests that the Commission should instead require transmission providers to submit a compliance filing in which they may propose a process to identify the transmission facilities for which the implementation of AARs and seasonal line ratings will provide the most benefits to customers.[100]

56. EEI states that its experience with AARs is that their use can provide benefits on a subset of transmission lines [101] and requests flexibility for transmission owners and transmission providers to implement transmission line rating solutions that best suit their needs.[102] EEI recommends a staggered AAR approach whereby AARs would first be implemented on priority designated facilities, using established and studied criteria, and any subsequent AAR implementation would occur following further studies of potential benefits.[103] Similarly, Entergy states that AARs allow for more flexibility in real-time operations than static/thermal values for real-time contingency studies,

[79] Exelon Comments at 1–2.

[80] Dominion Comments at 6.

[81] Indicated PJM Transmission Owners Comments at 1–2.

[82] Dominion Comments at 3; AEP Comments at 6–7; Indicated PJM Transmission Owners Comments at 5.

[83] ITC Comments at 1–3; Sunflower Comments at 2.

[84] MISO Transmission Owners Comments at 3–4.

[85] *Id.* at 13.

[86] *Id.* at 28.

[87] *Id.* at 22.

[88] *Id.* at 43–45.

[89] Southern Company Comments at 1–2; Eversource Comments at 6; NYTOs Comments at 10.

[90] Southern Company Comments at 1–2.

[91] *Id.* at 2.

[92] *Id.* at 4–5; NRECA/LPPC Comments at 19.

[93] Eversource Comments at 4–5.

[94] Southern Company Comments at 6.

[95] EEI Comments at 5–6.

[96] NYTOs Comments at 6–7.

[97] NERC Comments at 7.

[98] Duke Energy Comments at 5.

[99] *Id.* at 10.

[100] *Id.* at 5.

[101] EEI Comments at 5.

[102] *Id.* at 2–4.

[103] *Id.*

but contends that the use of AARs should follow a scientific application of factors that can reasonably result in an adjustment of facility ratings to those facilities for which an adjustment would be reasonably expected to provide benefits that exceed costs.[104]

57. NRECA/LPPC, Sunflower, and WAPA contend that the promised benefits, costs, and risks of AARs are not evenly distributed nationwide and that blanket application of the proposed AAR requirements poses difficult operating challenges.[105] NRECA/LPPC argue that the Commission should maintain a focus on safety and reliability and limit the scope of any final rule by applying the AAR requirements to transmission lines: (1) Rated 100 kV and above; (2) that are historically congested due to conductor limitations only; and (3) that are under RTO/ISO control. In addition, NRECA/LPPC argue that AAR requirements should be limited to transmission service used for near-term wholesale transactions, which in the RTOs/ISOs would be the day-head and real-time markets, and outside of the RTOs/ISOs, if applied, would be daily and hourly ATC, curtailment, and redispatch.[106] NRECA/LPPC and Sunflower further contend that, due to challenges in implementing AARs, utilities should have the flexibility to choose the AAR methodology best suited to their needs and should provide a waiver mechanism for particular circuits on which AAR implementation is difficult.[107]

58. Several Western Interconnection, non-CAISO transmission owners, including PacifiCorp, BPA, WAPA, and APS, broadly support the adoption of AARs due to the associated reduction in congestion, increase in transfer capability, and reliability improvements. However, these transmission owners request additional flexibility in how transmission owners apply AARs and urge the Commission to not adopt blanket AAR requirements for all transmission lines given differences in terrain, line lengths, and scarcity of temperature data for such lines.[108] In explaining the drawbacks to blanket AAR implementation, APS explains that non-congested transmission lines, transmission lines that are substation equipment-limited, and transmission lines that are voltage- and stability-limited will not benefit from AAR implementation.[109] WAPA further identifies additional AAR implementation challenges, including the installation of new devices, communication equipment, and cybersecurity challenges. To reduce implementation burdens, WAPA recommends that the Commission examine real-time Total Transfer Capability (TTC) calculations.[110] WAPA further cautions that it would have to pass the costs of AAR implementation on to all customers, even though only some customers would benefit.[111] BPA states that if it uses AARs as proposed, it would need to make its wind assumptions more conservative, de-rating transmission, to mitigate the risk of operating near the conductor limit.[112]

59. PacifiCorp, BPA, EEI, and IID further explain additional difficulties they would face implementing the proposed requirements to incorporate AARs into ATC that could render AAR implementation infeasible.[113] IID explains that, in the Western Interconnection, path limits are the result of multiple limits in series and in parallel. TTC calculations involve adjusting a base case with an associated series of activities, and failures in base case studies have to be evaluated manually, such that a generic equation would be insufficient in calculating transmission line ratings.[114] BPA and PacifiCorp explain that most congested parts on their transmission systems are lines that are operated in parallel as part of a rated transmission path,[115] that such rated paths have interactions with other paths, which result in operating nomograms,[116] and that the NOPR proposal may be more appropriate for a flow-based transmission system.[117] According to PacifiCorp and BPA, it may be infeasible to implement AARs as it would substantially increase the time to compute the constraints that they use to calculate TTC.[118] CAISO also describes the TTC calculation process using rated paths and states that using hourly AARs would exponentially increase the complexity of such calculations and would necessitate further automation.[119] Similarly describing the challenges of incorporating AARs into ATC, EEI explains that, in some areas, TTC values are determined annually, or even less frequently.[120]

60. California transmission owners urge more targeted AAR implementation.[121] PG&E recommends requiring transmission owners to determine which lines would realize net benefits for customers if AARs were deployed, noting that deployment of AARs across all transmission lines could result in a negative return on investment and an increased risk profile for the transmission system.[122] PG&E notes that most of its weather stations are currently located in ''High Fire Threat Districts'' and contends that AAR implementation on 500 kV lines will require planning for additional weather station equipment to ensure that accurate weather data is available.[123] SCE advocates for phased AAR implementation in which transmission owners identify priority facilities, and, after implementation, study their implementation in a report filed with the Commission.[124] SDG&E contends that settings for all relays will have to be studied and installed in the field, causing a significant cost burden unaccounted for in the Commission's analysis.[125] IID contends that the Commission should not take a one-size-fits-all approach and, in addition to the challenges of AAR implementation, encourages the Commission to consider the costs of software, equipment, and staffing in comparison to the benefits of AARs providing congestion relief.[126]

61. LADWP states that Southern California loads peak in the summer when temperatures are already high and may not allow AARs to expand transfer capability. Conversely, according to LADWP, there is already abundant transfer capability in the winter months.[127] Describing AAR implementation challenges, LADWP notes that, due to the diversity in terrain and microclimates that western transmission lines traverse, weather forecasts can vary significantly during volatile weather seasons and present

[104] Entergy Comments at 8.

[105] NRECA/LPPC Comments at 15–16, 19; Sunflower Comments at 5; WAPA Comments at 5.

[106] NRECA/LPPC Comments at 2–3.

[107] *Id.* at 3; Sunflower Comments at 5.

[108] PacifiCorp Comments at 2; BPA Comments at 2–4; WAPA Comments at 4–5; APS Comments at 2–4.

[109] APS Comments at 2–4.

[110] WAPA Comments at 7–9.

[111] *Id.* at 4–5.

[112] BPA Comments at 4–5.

[113] *Id.* at 3–4; PacifiCorp Comments at 2; IID Comments at 5–6; EEI Comments at 10–11.

[114] IID Comments at 5.

[115] BPA Comments at 3; PacifiCorp Comments at 2.

[116] Nomograms are operating constraints related to the flow on multiple paths that generally result from the simultaneous interaction between those paths.

[117] BPA Comments at 3; PacifiCorp Comments at 2.

[118] BPA Comments at 3; PacifiCorp Comments at 2.

[119] CAISO Comments at 10.

[120] EEI Comments at 11.

[121] PG&E Comments at 3; SCE Comments at 1–2; SDG&E Comments at 1–2; LADWP Comments at 2–3.

[122] PG&E Comments at 3.

[123] *Id.* at 9–10.

[124] SCE Comments at 3–4.

[125] SDG&E Comments at 4.

[126] IID Comments at 5.

[127] LADWP Comments at 3–4.

challenges in identifying the most constraining ambient conditions for a given transmission line.[128] LADWP therefore contends that the Commission should consider offering regional exceptions from the AAR requirements or prescribing AARs only in areas where significant benefits are expected.[129]

62. PJM generally supports the adoption of AARs by transmission providers. PJM states that it already employs AARs in its operations and day-ahead and real-time markets and that the use of AARs is commonplace among the overwhelming majority of transmission owners in the PJM region. PJM states that transmission owners' utilization of AARs increases operational flexibility, promotes a more efficient use of the transmission system, and results in more reliable system dispatch and cost-effective market operations.[130]

63. CAISO states that it currently uses seasonal line ratings, emergency ratings, and AARs. However, CAISO notes that AARs are used on relatively few facilities and involve a manual process to update transmission line ratings for an applicable period. CAISO states that, while AARs provide a more accurate understanding of the transfer capability of the transmission system, CAISO recommends that the Commission allow transmission owners and transmission providers to justify when they use AARs.[131]

64. MISO states that AAR and DLR deployment can support the efficient use of existing transmission infrastructure but is not a long-term solution to meet emerging system needs. MISO states that the Commission should not mandate the use of AARs where the burden of that deployment is greater than the benefits to be expected. MISO contends that the Commission should explore options for a more targeted application of identifying facilities that are good candidates for AARs based on objective criteria and documented methodologies.[132] MISO notes that it and MISO Transmission Owners have already commenced an effort to identify a prioritized list of candidate transmission facilities for deployment of real-time AARs in MISO.[133]

65. NYISO does not support a uniform approach to managing transmission line ratings and instead requests that each RTO/ISO work with the Commission to set objectives for its markets.[134] NYISO contends that AAR use would not provide benefits everywhere.[135] NYISO explains that using AARs to modify day-ahead transmission line ratings would overly complicate the day-ahead market solution and would reduce efficiency.[136] NYISO requests flexibility for regional variation with transmission line ratings given regional differences, such as transmission scheduling and market rules.[137] NYISO states that it could work with stakeholders to develop a proposal to implement three to four sets of seasonal line ratings that would be easier to implement and still achieve many of the NOPR objectives.[138]

66. Neither ISO–NE nor SPP explicitly takes a position on the NOPR proposal to implement AARs. However, ISO–NE states that most of the congestion that occurs on its system is due to voltage or stability limitations, and thus AAR benefits may be limited.[139] ISO–NE estimates that the implementation of AARs could result in the lowering of thermal congestion costs by, at most, approximately $5–10 million per year.[140] ISO–NE also contends, however, that AAR implementation may expose other binding system limitations without appreciably increasing transfer capability or reducing congestion.[141]

67. Market monitors are mostly supportive of the proposed AAR requirements.[142] The SPP MMU supports the proposed reforms to improve the accuracy and transparency of transmission line ratings used by transmission providers. The SPP MMU notes that numerous SPP transmission lines are not rated according to SPP Planning Criteria.[143] The SPP MMU states that it supports the use of DLRs for all transmission lines.[144] According to the SPP MMU, when transmission line ratings underestimate the actual transfer capability of the transmission system, this can result in restricted flows on certain paths while overloading others and can create a potential for de facto physical withholding of the available transfer capability by transmission owners.[145] The SPP MMU argues that more accurate transmission line ratings will improve the robustness of price formation, particularly in congested areas.[146]

68. Potomac Economics states that only 8% of the transmission line ratings in MISO are adjusted for changes in ambient air temperatures. Potomac Economics indicates that it conservatively estimates that the benefits of using AARs and emergency ratings in 2019 and 2020 would have been between 9% and 13% of the real-time congestion value, or $98 million and $114 million per year.[147] Potomac Economics notes that transmission owners have little or no economic incentive to provide temperature-adjusted ratings and that transmission operators [148] rarely verify or validate transmission line rating methodologies or transmission line rating calculations.[149] Potomac Economics contends that it would be unreasonable to require AARs on all transmission facilities, and instead argues that it would be more reasonable to require that processes be established to allow for additional AARs to be deployed quickly when new constraints begin to bind or other studies indicate it may be appropriate.[150] Potomac Economics cautions, however, against requiring any cost-benefit analysis, noting that the incremental cost of initiating AARs on new constraints is near zero so such analysis is unnecessary.[151] Finally, Potomac Economics contends that using AARs and emergency ratings will not create reliability concerns as the NOPR proposal only requires that decisions to not implement AARs or emergency ratings be based on reliability and not a preference or policy decision.[152] CAISO DMM supports the proposed requirements to implement hourly AARs as a way to improve both the accuracy of congestion costs and transmission system efficiency.[153]

[128] *Id.* at 5–6.

[129] *Id.* at 4–5.

[130] PJM Comments at 2.

[131] CAISO Comments at 2.

[132] MISO Comments at 9.

[133] MISO Comments at 14.

[134] NYISO Comments at 1.

[135] *Id.* at 2.

[136] *Id.* at 1–2.

[137] *Id.* at 2.

[138] *Id.* at 20.

[139] ISO–NE Comments at 4–6.

[140] *Id.* at 5 (basing estimates on 2019 data contained in IMM and EMM Reports and the Commission's estimates of potential savings from AARs in other RTO/ISO regions).

[141] *Id.* at 6.

[142] Potomac Economics Comments at 3–4; CAISO DMM Comments at 2–4; SPP MMU Comments at 1, 4.

[143] SPP MMU Comments at 4.

[144] *Id.* at 1, 4.

[145] *Id.* at 7.

[146] *Id.* at 9.

[147] Potomac Economics Comments at 7–9; *see also* Potomac Economics Reply Comments at 2–6.

[148] The NERC Glossary defines a ''Transmission Operator'' as: ''[t]he entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission Facilities.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[149] Potomac Economics Comments at 9–10; *see also* Potomac Economics Reply Comments at 6–7.

[150] Potomac Economics Comments at 20; *see also* Potomac Economics Reply Comments at 9.

[151] Potomac Economics Reply Comments at 7.

[152] *Id.* at 11.

[153] CAISO DMM Comments at 2, 4.

69. State government agencies are also mostly supportive of the proposed AAR requirements.[154] New England State Agencies state that they strongly support the Commission's proposed AAR requirements.[155] New England State Agencies state that the transmission system was built on behalf of and paid for by ratepayers, and argue that the Commission should take all reasonable steps to protect those ratepayers from excessive costs. New England State Agencies contend that the use of AARs can be an important tool in this regard.[156] New England State Agencies state that a transmission system operated using AARs may provide benefits by possibly: (1) Obviating the need for new transmission lines, thus deferring capital costs; [157] (2) reducing reliance on higher cost local reserves which will reduce costs and local reserve requirements resulting from an increased ability to flow power into load pockets; [158] and (3) helping with the integration of new clean energy resources.[159] Finally, New England State Agencies argue that, because parts of MISO as well as most of ERCOT are already employing AARs, there can be no serious argument that AARs are too difficult or costly to implement as was suggested by some transmission owners.[160]

70. OMS states that it supports the NOPR proposal that AAR requirements generally apply to all transmission lines and not just those with historical congestion.[161] OMS notes that the most expensive energy prices typically occur after unforeseen outages or weather events and are not the result of chronic, well understood scenarios. However, OMS also states that it does not support requiring AARs on those facilities where it is uneconomical or unreliable to do so.[162] OMS contends that the Commission should require RTOs/ISOs to develop a process whereby transmission owners transparently work with the RTOs/ISOs and market monitors to demonstrate why any exceptions from the requirements are justified.[163]

71. Ohio FEA also supports the AAR NOPR proposal, stating that AARs help ratepayers to realize the full benefits of their transmission system investment. Ohio FEA explains that the four Ohio transmission owners have already recognized the benefits of AARs, as a way of moving away from static ratings.[164] However, UDPU contends that the AAR NOPR proposal should be limited to certain historically congested facilities until the Commission has better information to assess the costs and benefits of broad AAR implementation.[165]

72. CEA encourages the Commission to further consider the costs associated with the proposed changes, as a broader use of AARs may over-estimate the benefit to cost ratio. CEA contends that the use of AARs presents a significant cost challenge considering the number of upgrades required.[166]

73. Other technical experts are also supportive of more accurate transmission line ratings.[167] R Street Institute states that understated transmission line ratings can result in increased congestion costs and underutilization of generation in export-constrained locales, which is disproportionately zero-emission generation.[168] R Street Institute contends that the Commission should require DLRs by default and permit exceptions where justified by a cost-benefit analysis.[169]

74. WATT supports the direction the Commission is taking with the NOPR's AAR requirements, but explains that additional factors that affect transmission line ratings but are not incorporated into AARs are very knowable.[170] WATT contends that the Commission should require the use of DLRs when certain criteria are met.[171] LineVision supports WATT's comments and states that DLR implementation will also result in additional accuracy and situational awareness.[172]

75. Renewable energy advocates are also generally supportive of the AAR NOPR proposal, but urge the Commission to take further measures to spur the implementation of DLRs.[173] For example, ACORE commends the Commission for issuing the NOPR, but recommends the Commission take further steps to encourage DLR deployment by incenting its deployment through transmission incentives and incorporating its assessment into transmission planning processes.[174] Similarly, Clean Energy Parties contend that AARs are easy to implement and a modest improvement over static line ratings.[175] However, Clean Energy Parties argue that DLR is superior to AAR, though Clean Energy Parties do not contend a blanket DLR mandate is appropriate.[176] ACPA/SEIA support accurate transmission line ratings, and contend that the Commission should require *all* transmission owners and transmission providers to study the costs and benefits of implementing DLRs on persistently congested transmission lines and require implementation where warranted.[177] ACPA/SEIA and Clean Energy Parties both argue that the Commission should alter its NOPR proposal to prioritize transmission lines that are expected to be congested, persistently congested, or likely to be congested in the future.[178]

76. Generator owners and representatives are also generally supportive of the proposed AAR requirements.[179] EDFR argues that getting the transmission line rating policy right is important due to the urgency of addressing the climate crisis and President Biden's carbon emissions reduction goals. EDFR contends that a lack of adequate transfer capability can cripple clean energy generation.[180] EDFR further explains that, under many offtake agreements in RTO/ISO markets, the developer is paid a fixed price for energy at a market hub and if congestion limits the project's ability to deliver power to the hub, then the developer bears the risk (known as basis risk). EDFR argues that congestion is difficult to hedge in an effective way because system topology and conditions change unexpectedly over time, but states that more accurate transmission line ratings will decrease basis risk and hedging difficulties.[181] EDFR contends that prioritization should not only consider historical congestion, but should consider future congestion based on transmission planning, interconnection, and transmission service studies for purposes of prioritizing implementation.[182]

[154] New England State Agencies Comments at 10; OMS Comments at 2; Ohio FEA Comments at 2.

[155] New England State Agencies Comments at 10.

[156] *Id.*

[157] *Id.* at 10–11.

[158] *Id.* at 12.

[159] *Id.*

[160] *Id.*

[161] OMS Comments at 8–10; *see also* OMS Reply Comments at 7, 10.

[162] OMS Comments at 9.

[163] *Id.*

[164] Ohio FEA Comments at 2–4.

[165] UDPU Comments at 1–3.

[166] CEA Comments at 2.

[167] R Street Institute Comments at 1; WATT Comments at 1–2; LineVision Comments at 1–2.

[168] R Street Institute Comments at 1.

[169] *Id.* at 3, 5–7.

[170] WATT Comments at 1–2.

[171] *Id.* at 10–12.

[172] LineVision Comments at 1–2.

[173] ACORE Comments at 1; Clean Energy Parties Comments at 2, 4–6.

[174] ACORE Comments at 1.

[175] Clean Energy Parties Comments at 4–5.

[176] *Id.* at 5, 8.

[177] ACPA/SEIA Comments at 5–7.

[178] *Id.* at 8–9; Clean Energy Parties Comments at 8, 10.

[179] ENEL Comments at 1; EDFR Comments at 1–2; Vistra Comments at 1–2; EPSA Comments at 2.

[180] EDFR Comments at 2.

[181] *Id.*

[182] *Id.* at 4.

77. EPSA contends that the Commission should encourage the use of technological advances that improve transmission operators' ability to track and optimize transmission line ratings and usage where feasible and cost effective. EPSA states that PJM's adoption of AAR requirements has shown clear benefits.[183] Vistra is supportive of the Commission's NOPR proposal, stating that it is imperative that the Commission act now to make best use of existing infrastructure and that AARs and DLRs are the best way to do that.[184]

78. Industrial Customer Organizations, TAPS, and Certain TDUs are also broadly supportive of the AAR NOPR proposal.[185] Certain TDUs state that they support the proposed rule and encourage the Commission to mandate improvements to the accuracy and transparency of transmission line ratings because not all transmission owners have shown a willingness to make these improvements voluntarily.[186] Certain TDUs state that they support the use of AARs as a way to better utilize the existing transmission system, noting that it will become imperative that the existing transmission system is utilized to the greatest extent possible as additional renewable resources come online.[187]

79. Industrial Customer Organizations state that they generally support the proposed rules, but assert that these rules should be implemented as soon as practicable.[188] Industrial Customer Organizations argue that, if prioritization is needed, congested circuits should be prioritized.[189] Industrial Customer Organizations explain that understated transmission line ratings increase congestion and may lead to curtailments. Industrial Customer Organizations contend that transmission owners that understate transmission line ratings may create an illusory need for transmission upgrades. Further, Industrial Customer Organizations contend that some transmission line ratings may be deliberately understated because transmission owners may have a profit incentive to calculate understated transmission line ratings in order to benefit local generation.[190]

[183] EPSA Comments at 2.

[184] Vistra Comments at 1–2.

[185] Industrial Customer Organizations Comments at 1–2; TAPS Comments at 1–2; Certain TDU Comments at 1.

[186] Certain TDUs Comments at 4.

[187] *Id.* at 4–5.

[188] Industrial Customer Organizations Comments at 15–18.

[189] *Id.* at 18–19.

[190] *Id.* at 4.

80. TAPS states that it supports the proposed broad application of AARs because it reduces the likelihood that AARs will be implemented in a discriminatory manner.[191] Similarly, Clean Energy Parties cite Order No. 888,[192] in which the Commission stated that ''[d]enials of access [to transmission services] (whether they are blatant or subtle), and the potential for future denials of access [to transmission services], require the Commission to revisit and reform its regulation of transmission in interstate commerce.'' [193] According to Clean Energy Parties, Order No. 888 supports the assertion that a lack of consistency and transparency in transmission line ratings creates the potential for future denials of access to transmission service, as inaccurate transmission line ratings are used to provide discriminatory transmission service to preferential customers.[194]

81. Additionally, TAPS notes that the NOPR proposal would require the use of AARs when evaluating requests for near-term point-to-point transmission service and contends that the Commission should also apply the requirements to requests for near-term secondary service requests and near-term network resource designations. TAPS explains that secondary service comes ahead of non-firm point-to-point transmission service in curtailment priority, and the NOPR proposal flips this priority.[195]

82. Prysmian discourages mandatory AAR implementation without consideration of other variables and without a holistic evaluation of all transmission line rating inputs to determine whether an overall transmission line rating methodology is conservative or not. Prysmian states that AARs can also lead to situations in which near-term transfer capability is overstated.[196]

[191] TAPS Comments at 7.

[192] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002).

[193] *Id.* at 31,652.

[194] Clean Energy Parties Comments at 2–3.

[195] TAPS Comments at 20.

[196] Prysmian Comments at 1.

c. Commission Determination

83. In this final rule, we adopt with certain modifications the NOPR proposal to require transmission providers to apply the AAR requirements set forth in *pro forma* OATT Attachment M to all transmission lines, subject to the exceptions described below in Section IV.D.3.[197] As discussed above, the AAR requirements will ensure that transmission line ratings are more accurate. In turn, more accurate transmission line ratings will ensure wholesale rates more accurately reflect the cost of the wholesale service being provided (*i.e.,* energy, capacity, ancillary services, or transmission service) and, thus, that those wholesale rates are just and reasonable. We further describe, below, the requirements and the modifications to the NOPR proposal adopted herein.

84. First, we adopt the proposal to apply the AAR requirements as set forth under ''Obligations of Transmission Provider'' in *pro forma* OATT Attachment M to all transmission lines subject to the exceptions described below in Section IV.D.3. We find that applying the AAR requirements to all transmission lines will both ensure that wholesale rates remain just and reasonable and strike an appropriate balance between benefits and challenges of AAR implementation. For this reason, we do not adopt the phased-in implementation schedule proposed in the NOPR in which a transmission provider would initially implement AARs on only historically congested lines.

85. As the Commission preliminarily found in the NOPR [198] and as the record demonstrates, despite differences across transmission systems, simply accounting for ambient air temperatures in transmission line ratings can reliably increase power transfer capability, resulting in significant reliability, operational, and economic benefits. Numerous commenters describe these benefits.[199] For example, Potomac Economics estimates that the benefits to AAR implementation in MISO alone would have produced approximately $67 million and $49 million in reduced congestion costs in 2019 and in 2020,

[197] NOPR, 173 FERC ¶ 61,165 at PP 92, 102.

[198] *Id.* P 99.

[199] MISO Transmission Owners Comments at 8–9; PacifiCorp Comments at 2; EEI Comments at 4–5; Entergy Comments at 1–2; BPA Comments at 2–4; NYTOs Comments at 2–3, 5; Duke Energy Comments at 6–7; PG&E Comments at 1; LADWP Comments at 2–3; ITC Comments at 1–3; Sunflower Comments at 2; Exelon Comments at 1–2; AEP Comments at 3; Indicated PJM Transmission Owner Comments at 2; PJM Comments at 2; PJM Comments at 2; New England State Agencies Comments at 7; TAPS Comments at 5.

respectively.[200] Exelon describes AARs as a best practice that cost-effectively enhances transmission utilization, benefiting customers, without adverse safety and reliability impacts.[201] EEI acknowledges that experience with AARs shows that their use can provide benefits on certain subsets of transmission facilities.[202] PJM states that, in its experience, AARs increase operational flexibility, promote a more efficient use of the transmission system, and result in more reliable system dispatch and cost-effective market operations.[203] New England State Agencies argue that the Commission should take all reasonable steps to protect ratepayers from excessive costs and that the use of AARs, by permitting more power to flow than a system operated using static or seasonal line ratings, can be an important tool in this regard.[204] Similarly, TAPS explains that reliance on static and seasonal line ratings inflicts unnecessary costs on consumers and contends that deployment of AARs using commercial temperature forecasts can produce significant benefits to consumers at low cost.[205] While several entities note implementation costs as a barrier, these costs are mostly initial investment costs in EMS improvements to accommodate AARs, implementation of a ratings database, and review (and potentially reset) of protective relays settings.[206] Once these initial investments are made, adding AARs to additional transmission lines appears to have a minimal incremental cost.[207]

86. Second, in this final rule we adopt a requirement for transmission providers to use AARs when evaluating the availability of and requests for near-term transmission service (under sections 15, 17, 18, and 29 of the *pro forma* OATT).[208] For purposes of this requirement, we define ''requests for near-term transmission service'' to include not only requests for near-term point-to-point transmission service, but also network resource designations and secondary service where the start and end date of the designation/request is within the next 10 days. Specifically, we require transmission providers to use AARs as the relevant transmission line ratings when: (1) Evaluating requests for near-term transmission service, defined as transmission service ending within 10 days of the date of the request; (2) responding to requests for information on the availability of potential near-term transmission service (including requests for ATC or other information related to potential service); and (3) posting ATC or other information related to near-term transmission service to their OASIS site. As discussed further below, in response to comments, we modify this requirement from the NOPR proposal to include near-term network and near-term secondary service, as well as the near-term point-to-point transmission service proposed in the NOPR.[209]

87. Third, we adopt the Commission's proposal in the NOPR to require that transmission providers use AARs as the relevant transmission line rating when determining whether to curtail or interrupt near-term point-to-point transmission service (under sections 13.6 and/or 14.7 of the *pro forma* OATT) [210] if such curtailment or interruption is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within the next 10 days.[211]

88. Fourth, we adopt the proposal in the NOPR [212] to require that transmission providers use AARs as the relevant transmission line ratings when determining whether to curtail network or secondary service (under section 33 of the *pro forma* OATT) or redispatch network or secondary service (under sections 30.5 and/or 33 of the *pro forma* OATT), if such curtailment or redispatch is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination.

89. Fifth, we adopt and modify the proposal in the NOPR to allow RTOs/ISOs to comply with the final rule's AAR requirements by revising their OATTs to require implementation of AARs within their security constrained economic dispatch (SCED) and security constrained unit commitment (SCUC) models (and in any relevant related models) in both the day-ahead and real-time markets and reliability unit commitment (RUC) processes,[213] and any other intra-day RUC processes.[214] As the Commission recognized in the NOPR, such entities have Commission-approved variations from the *pro forma* OATT to manage congestion and initiate curtailments and/or redispatch of transmission service within their footprints (although generally not at their borders) through mechanisms such as SCED and SCUC. As discussed in Section IV.B.3.b, we adopt the Commission's NOPR proposal to require that transmission providers—including RTOs/ISOs—update their AARs at least hourly. As discussed in Sections IV.B.3.b and IV.B.3.c, for any seams-based transmission service offered by RTOs/ISOs, we adopt the Commission's NOPR proposal to implement the near-term transmission service requirements for inclusion of up-to-date hourly AAR calculations in ATC.

90. We do not adopt the NOPR proposal to establish a definition of historically congested transmission lines. Accordingly, since we are not adopting the NOPR's proposed definition of historically congested transmission line, and instead apply the AAR requirements adopted herein to all transmission lines, we do not address comments related to the NOPR's proposed definition of historically congested transmission line. To the

[200] Potomac Economics Comments at 7–8.

[201] Exelon Comments at 1.

[202] EEI Comments at 5.

[203] PJM Comments at 2.

[204] New England State Agencies Comments at 5–6, 10–11.

[205] TAPS Comments at 5.

[206] Indicated PJM Transmission Owner Comments at 5–6; Exelon Comments at 14; AEP AD19–15 Post Technical Conference Comments at 3.

[207] Exelon Comments at 8; Indicated PJM Transmission Owner Comments at 5–6; AEP Post-Technical Conference Comments at 2–3; September 2019 Technical Conference, Day 1 Tr. at 180–181.

[208] NOPR, 173 FERC ¶ 61,165 at P 87.

[209] Although requests for network transmission service are typically long-term requests, meriting their evaluation using seasonal line ratings, we note the Commission's finding in Order No. 890 that the minimum term for network transmission service should be the same as the minimum time period used for firm point-to-point transmission service (*i.e.,* daily). *See Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), 118 FERC ¶ 61,119, at P 1505, *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), 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, 129 FERC ¶ 61,126 (2009). As such, any requests for transmission service that fall within the near-term threshold defined herein would qualify as near-term network transmission service.

[210] Additionally, we add references to interruption or curtailment of near-term point-to-point transmission service occurring pursuant to 13.6 of the *pro forma* OATT to Attachment M in order to ensure consistent treatment of firm and non-firm point-to-point transmission service.

[211] NOPR, 173 FERC ¶ 61,165 at P 89.

[212] *Id.* P 90.

[213] After the day-ahead market process takes place, RTOs/ISOs typically perform one or more residual unit commitment processes, or what we refer to here as RUC, to address remaining resource gaps and reliability issues or to manage uncertainty and the potential for real-time operational issues. The exact names, definitions, and market processes implementing what we refer here to as RUC processes differ across RTOs/ISOs. For example, CAISO refers to its process as residual unit commitment, SPP uses reliability unit commitment, and MISO uses reliability assessment commitment. For simplicity, however, this final rule uses the term RUC to refer to all of these relevant processes in all of the RTO/ISO markets interchangeably.

[214] NOPR, 173 FERC ¶ 61,165 at P 91. The statement ''(and in any relevant related models)'' was intended to encompass all RUC processes within the timeframe. In the interest of clarity, we modify the NOPR proposal here to make that more explicit.

extent that commenters were arguing for a narrower application than what we adopt in this final rule, below we explain the basis for application of the AAR requirements to all transmission lines.

91. Finally, we alter the proposed compliance schedule. Specifically, we require each transmission provider to submit a compliance filing within 120 days of the effective date of this final rule to incorporate into its OATT the changes adopted herein consistent with *pro forma* OATT Attachment M and the changes to the Commission's regulations set forth below. Additionally, we further require that all requirements adopted herein be fully implemented no later than three years from the compliance filing due date established by this final rule.

92. In response to comments received in response to the NOPR, we modify the NOPR proposal's defined term ''near-term point-to-point transmission service'' to instead be ''near-term transmission service.'' As a result, the AAR requirements will apply to requests for near-term network transmission service, near-term secondary service, and near-term point-to-point transmission service, provided that such service meets the 10-day threshold defined in the near-term transmission service definition. We agree with TAPS that it would be inappropriate to apply the AAR requirements only to requests for near-term point-to-point transmission service and not to requests for near-term network and near-term secondary service because secondary service comes before non-firm point-to-point transmission service in curtailment priority.[215] More generally, we find that a requirement to use AARs on all types of near-term transmission service will better ensure that transmission line ratings are accurate and that wholesale rates are just and reasonable.

93. Although commenters broadly raise concerns with adopting transmission line ratings that may fluctuate widely or contend that implementing AARs on certain transmission lines may not yield benefits, we do not find that these concerns and arguments overcome the need to improve the accuracy of transmission line ratings through applying the AAR requirements to all transmission lines. Specifically, we decline to accommodate requests for more targeted AAR requirements in which transmission providers would either have flexibility to identify candidate transmission lines or the Commission would require AAR implementation on only priority transmission lines, such as only on historically congested lines.

94. We recognize commenters' concerns, such as those from NRECA/LPPC, that the promised benefits, costs, and risks of implementing AARs may not be evenly distributed nationwide.[216] Nevertheless, we find that with the broad AAR requirements adopted herein, the overall benefits via savings to load and lower congestion charges to generators will on balance outweigh the costs. Moreover, we acknowledge the difficulty of knowing in advance all the locations and situations in which the benefits of AAR implementation will outweigh the costs. Given the difficulty in predicting unexpected congestion before it happens, narrowing the scope of the AAR requirements would limit the ability of these reforms to ensure just and reasonable wholesale rates. In particular, we find that the AAR requirements adopted in this final rule are beneficial in mitigating the impact of transient congestion, *i.e.,* temporary or short-term congestion that does not occur on a regular basis, such as congestion caused by unexpected equipment outages or other unusual conditions. Furthermore, given the increasing occurrence of extreme weather events, we expect that assessing the benefits of broader AAR implementation based on historical congestion likely understates the potential savings associated with implementation of the AAR requirements adopted in this final rule. By contrast, the record demonstrates that AAR implementation costs are predominantly one-time investment costs in EMS improvements to accommodate AARs, implementation of a ratings database, and review (and potentially reset) of protective relays settings.[217] Once these costs have been incurred, the incremental cost of applying AARs to additional transmission facilities is minimal.[218]

95. Attempts to anticipate the situations in which AARs will not be cost beneficial (*e.g.,* attempts to forecast locations and situations in which there will be future congestion and deploy AARs in only those anticipated situations) will necessarily be imperfect and complex, especially during infrequent but consequential events. Additionally, since many emergencies may come and go before new AARs can be developed and implemented for newly congested transmission lines, a more targeted AAR requirement advocated by some commenters may not accurately represent system transfer capability in such critical situations. As the Commission recognized in the NOPR, congestion is difficult to predict, particularly during emergency conditions.[219] The 2019 FERC and NERC Staff Report on the January 2018 South Central cold weather event illustrates this point.[220] As shown by that event, during times of emergency or system stress, flows may change considerably from normal operations and the increased transfer capability provided through AARs may prove valuable even on transmission lines that are not typically congested.[221] In addition, in the February 2021 cold weather event, MISO experienced unprecedented east-to-west flows throughout the footprint and accrued $773 million in congestion charges in just a few days.[222] We note that with broad AAR implementation, given Potomac Economics' finding that AAR implementation consistently results in savings of approximately 5% to 8% of total congestion,[223] congestion cost savings from this single event might have exceeded the total costs of AAR implementation in the region. Moreover, many argue that the changing generation mix makes congestion prediction even more difficult.[224] Additionally, AAR implementation itself will have secondary consequences for congestion patterns, as changes to transmission line ratings may change generation dispatch patterns and, by extension, congestion patterns. Such secondary congestion consequences may only be able to be promptly addressed by a broad AAR requirement that applies to all transmission lines.

96. Beyond congestion costs, during times of stressed system conditions, operators in RTOs/ISOs might have to

[215] TAPS Comments at 18–20.

[216] NRECA/LPPC Comments at 15.

[217] Exelon Comments at 8–9.

[218] *Id.* at 8; Indicated PJM Transmission Owner Comments at 5–6; AEP Post-Technical Conference Comments at 2–3; September 2019 Technical Conference, Day 1 Tr. at 180–181.

[219] NOPR, 173 FERC ¶ 61,165 at P 93.

[220] 2019 FERC and NERC Staff Report, *The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018,* at 96 (July 2019) (FERC and NERC Staff Report), *https://www.ferc.gov/sites/default/files/2020-05/07-18-19-ferc-nerc-report_0.pdf.*

[221] NOPR, 173 FERC ¶ 61,165 at P 93.

[222] OMS Comments at 10; OMS Reply Comments at 7; *see* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), *https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.*

[223] Potomac Economics Comments at 8; Potomac Economics Post-Technical Conference Comments at 5–6.

[224] ACPA/SEIA Comments at 8, 11; EPSA Comments at 4; New England State Agencies Comments at 6.

spend limited time requesting AARs from transmission owners on an *ad hoc* basis.[225] AAR implementation on all transmission lines will help ensure transmission providers have sufficient transfer capability and flexibility to manage emergency conditions. Delayed access to AARs could force transmission operators to spend precious time reaching out to transmission owners for AARs, rather than using such time to manage emergency conditions. Instead, AAR implementation on all transmission lines will alleviate the need for transmission providers to spend time requesting AARs when there may be no time to waste.

97. Further, arguments that the benefits of broad AAR implementation will not outweigh the costs are inconsistent with the ERCOT and PJM transmission owners' actual AAR implementation experience. AEP has been implementing AARs for decades and has realized both reliability and financial benefits for its customers.[226] As Indicated PJM Transmission Owners state, transmission owners in PJM provide AARs for each of their facility ratings.[227] PJM further states that the use of AARs is commonplace among the overwhelming majority of transmission owners in PJM.[228] As New England State Agencies observe, the broad experience implementing AARs does not support the argument that AARs are too difficult or costly to implement.[229]

98. In response to MISO Transmission Owners' argument that the Commission should not rely on Potomac Economics' estimates of the benefits of AARs, our rationale for the AAR requirements adopted in this final rule is not solely based on Potomac Economics' analysis. Rather, our rationale is based on the finding that AARs on all transmission lines will ensure that wholesale rates more accurately reflect the cost of the wholesale service being provided, and, thus that those wholesale rates are just and reasonable. This finding is further informed by the widespread benefits experienced by commenters implementing AARs broadly in PJM and ERCOT, the expectation that the benefits of AAR implementation will be greatest on transmission lines that are frequently congested, along with the understanding of the difficulty of predicting congestion and the low incremental cost to implement AARs. However, in response to MISO Transmission Owners' critique that Potomac Economics' analysis erroneously assumes that all transmission lines in MISO are ambient adjustable, we note that, in response to MISO Transmission Owners' comments, Potomac Economics states that its analysis does not assume that all transmission lines are able to be rated using AARs and instead removes from the analysis all transmission lines that currently have summer ratings equal to winter ratings.[230] With respect to MISO Transmission Owners' argument that Potomac Economics' analysis erroneously assumes that all transmission lines in MISO are currently using worst-case ambient air temperature assumptions, we note that Potomac Economics does not uniformly assume worst-case 104 degrees Fahrenheit as the basis for adjusting AARs, but instead infers unique transmission owner base assumptions using maximum historical temperatures in each transmission owner service territory.[231] Finally, we disagree with MISO Transmission Owners' assertion that the benefits in Potomac Economics' analysis are inflated because of certain transmission outages or upgrades assumptions. As Potomac Economics explains, there are many generalized and localized factors that might increase or decrease congestion in an individual year and, given the highly complex nature of the electric system, incorporating all of these factors is not possible.[232] Despite certain generalizations, which we believe are likely to render Potomac Economics' analysis conservative, Potomac Economics has consistently found that AARs and emergency ratings will reduce congestion by 10% to 15% annually.[233]

99. We disagree with arguments from Southern Company, EEI, and other commenters that reliability issues may arise because AARs may create difficulties in identifying the most limiting element and similar difficulties and costs associated with complying with Reliability Standard PRC–023–4's transmission relay loadability requirements that depend on maximum published ratings. Reliability Standard PRC–023–4 requires setting transmission line relays at values at or above 115 to 170% of various maximum values for current or power carrying capability, *e.g.,* 115% of the highest seasonal 15-minute Facility Rating of a circuit or 150% of the highest seasonal four-hour Facility Rating of a circuit. We do not agree that this final rule will result in PRC–023–4 related relay setting changes to ''thousands'' [234] of relays, since the relay settings are currently calculated based on practical limitations which in the majority of cases should not exceed AAR values. In addition, PJM has long implemented AARs and, rather than describing reliability challenges, contends that AAR implementation creates reliability benefits.[235] For example, PJM states that the adoption of AARs increases operational flexibility, promotes a more efficient use of the transmission system, and results in more reliable system dispatch and cost-effective market operations.[236] Transmission owners in PJM have implemented AARs despite the initial cost incurred to update relay settings. Likewise, AEP submits that it has implemented AARs for decades and that AAR implementation presents reliability benefits.[237]

100. In response to concerns about the additional challenges associated with incorporating AARs into ATC, as raised by Duke Energy, EEI, and several non-RTO/ISO transmission owners with service territories in the Western Interconnection, we note that such TTC calculation practices, and in turn ATC practices, particularly those which only update TTC values annually,[238] will need to be updated in order to comply with this final rule's AAR requirements. In fact, such practices may already be out of compliance with the Commission's *existing* ATC calculation rules. For example, while Order No. 890 provides transmission providers with significant flexibility in what approach they take to determine ATC in their transmission paths, it also requires that ATC values (regardless of the approach used to calculate them) be ''updated and benchmarked to actual events.'' [239] Furthermore, in May 2021, the Commission issued Order No. 676–J,[240] in which the Commission (among other things) codified the ''fundamentals of Order No. 890 requirements for calculating ATC'' in the Commission's regulations.[241] Specifically, Order No.

[225] OMS Reply Comments at 7; *see also* FERC and NERC Staff Report at 56–59; ISO–NE, *Cold Weather Operations: December 24, 2017—January 8, 2018,* at 41 (Jan. 16, 2019), *https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf.*

[226] AEP Comments at 3.

[227] Indicated PJM Transmission Owners Comments at 6–7.

[228] PJM Comments at 2.

[229] New England State Agencies Comments at 11–12.

[230] Potomac Economics Reply Comments at 3–5.

[231] *Id.* at 2–3.

[232] *Id.* at 5–6.

[233] *Id.* at 5.

[234] EEI Comments at 5–6.

[235] PJM Comments at 7.

[236] *Id.* at 2.

[237] AEP Comments at 3.

[238] EEI Comments at 11.

[239] Order No. 890, 118 FERC ¶ 61,119 at P 290.

[240] *Standards for Business Practices and Communication Protocols for Public Utilities,* Order No. 676–J, 86 FR 29491 (June 2, 2021), 175 FERC ¶ 61,139 (2021).

[241] *Id.* P 38.

676–J revised section 37.6(b)(2)(i) of the Commission's regulations to codify that ATC calculations must be ''conducted in a manner that is . . . consistent with anticipated system conditions and outages for the relevant timeframe.'' [242] We find that transmission line ratings represent one such ''system condition'' with which ATC calculations must be consistent.

101. In response to specific concerns from PacifiCorp and BPA about nomogram constraints, we note that nomogram constraints are typically used to represent transfer capability on facilities with stability or voltage limitations. The AAR requirements adopted in *pro forma* OATT Attachment M exempt transmission lines whose ratings are not affected by ambient air temperature.

102. In response to comments from NERC requesting further consideration of AAR implementation on long transmission lines, and from LADWP, and other, primarily western transmission owners, which describe AAR implementation challenges due to the diversity in terrain and microclimates that western transmission lines traverse, we agree that longer transmission lines can and will experience differing weather conditions across the length of those transmission lines. To maintain reliable system operations, we expect transmission providers to implement the transmission line rating calculated based on the most limiting element under the prevailing weather conditions (actual or anticipated) at the relevant point on the transmission line. In the case of transmission conductors, which might be exposed to different weather conditions along the length of the transmission line, transmission providers must rate such elements using the most limiting weather conditions, in accordance with good utility practice. However, this requirement does not require the installation of field devices or sensors, as some transmission owners suggest.[243] Rather, as proposed in the NOPR, the AAR requirements can be met through the use of a weather data service.[244]

103. Similarly, in response to comments from BPA that if BPA uses AARs as proposed, it would need to make its current liberal wind assumptions (and therefore, the resultant transmission line ratings) more conservative to mitigate the risk of operating near the conductor limit,[245] we reiterate that the AAR requirements will ensure more accurate transmission line ratings, not necessarily higher transmission line ratings. We further clarify that there is no requirement to change wind speed assumptions. Utilities have operated reliably for decades with AARs.[246] However, if any transmission owner finds it necessary to change its wind speed assumptions consistent with good utility practice, we clarify that nothing in this rulemaking prevents it from doing so.

2. Specific AAR Implementation Requirements

a. Use of AARs 10-Days Forward in Transmission Service and Operations

i. NOPR Proposal

104. In the NOPR, within the context of the AAR requirements described and adopted above in Section IV.B.1, the Commission proposed to apply the AAR requirements to transmission service that starts/ends within 10 days, to the curtailment or interruption of point-to-point transmission service anticipated to occur (start and end) within the next 10 days, and to the curtailment of network transmission service or secondary service or redispatch network transmission service or secondary transmission service anticipated to occur (start and end) within 10 days (hereinafter referred to as the ''10-day threshold'').

105. The Commission justified the proposed 10-day threshold as a reasonable cut-off beyond which forecasts may not be accurate enough for AARs to provide significant value, and by stating that the Commission believed that such a limit would reasonably accommodate requests for weekly point-to-point transmission service. The Commission further noted that ambient air temperature forecasts for intervals beyond the proposed 10-day threshold tend to converge to the longer-term ambient air temperature forecasts used in seasonal line ratings.[247] Finally, the Commission noted that its proposal allowed transmission providers to determine (consistent with good utility practice) the needed degree of certainty when constructing their forecasts of ambient air temperature.[248]

106. With respect to RTOs/ISOs, the Commission proposed to require AARs as the relevant transmission line rating for any point-to-point transmission service offered (*e.g.,* at their borders). However, the Commission also recognized that RTOs/ISOs have Commission-approved variations from the *pro forma* OATT to manage internal congestion and initiate curtailments and/or redispatch of transmission service within their footprints through mechanisms such as SCED and SCUC. To accommodate these variations, the Commission proposed that RTOs/ISOs comply with the proposed requirements by revising their OATTs to require implementation of AARs within their SCED and SCUC models (and in any relevant related models) in both the day-ahead and real-time markets and any intra-day RUC processes. For real-time markets, the Commission proposed that RTOs/ISOs update their AARs at least hourly. For any point-to-point transmission service offered by RTOs/ISOs (*e.g.,* at their borders), the Commission proposed that the AAR requirements discussed above for point-to-point transmission service would apply. As justification, the Commission explained that day-ahead markets already rely upon forecasts of weather to inform next-day load and intermittent generation availability. The Commission preliminarily agreed with PJM that temperatures can be forecast with a reasonable degree of certainty in day-ahead markets.[249] The Commission further stated that, within its NOPR proposal, transmission providers could (consistent with good utility practice) determine the needed degree of certainty when constructing their forecasts of ambient air temperature, and that, because one of the goals of the day-ahead market is to align prices with those eventually determined in the real-time market, maintaining policy consistency between the day-ahead and real-time markets, where practical, is desirable.[250]

ii. Comments

107. Many commenters generally support the Commission's proposed AAR requirements without specifically discussing the 10-day threshold.[251] Industrial Customer Organizations specifically agree with the Commission that implementing AARs in near-term transmission service will more accurately reflect the cost of delivering

[242] *Id.*

[243] WAPA Comments at 7–9; PG&E Comments at 9–10.

[244] NOPR, 173 FERC ¶ 61,165 at P 95.

[245] BPA Comments at 4.

[246] AEP Comments at 3.

[247] NOPR, 173 FERC ¶ 61,165 at PP 87–88.

[248] *Id.* P 102.

[249] PJM Post-Technical Conference Comments at 3.

[250] NOPR, 173 FERC ¶ 61,165 at P 102.

[251] EPSA Comments at 2; Clean Energy Parties Comments at 2–3; R Street Institute Comments at 2–3; TAPS Comments at 1–3; ACORE Comments at 3; OMS Comments at 2; New England State Agencies Comments at 10; Vistra Comments at 2–3.

energy to load.[252] CEA states that using AARs to calculate transmission line ratings for service requests up to 10 days has proven to be reliable and to provide benefits to effective and reliable transmission operations.[253] EDFR contends that the distinction between AARs and seasonal line ratings depending on the applicable time frame appears sensible.[254] ACPA/SEIA state that they support the Commission's proposed requirements for near-term point-to-point transmission service and curtailments expected to occur within the next 10 days.[255] The Ohio FEA does not take a firm position, but states that implementing AARs for the next 10 days is reasonable.[256] OMS states that the weather data required to implement AARs is already widely available through public sources and used for load and resource forecasting.[257]

108. While not supporting or opposing the proposed 10-day threshold, EPRI recommends an independent assessment that documents the accuracy and risk associated with weather forecast data, explaining that not all weather forecast data will be appropriate for transmission line ratings and that some limiting spans run through microclimates. EPRI further explains that inaccurate forecast risks can be mitigated by identifying and implementing corrective factors to allow forecasts to be used consistent with good utility practice. EPRI suggests utility-specific rating studies would be required to assess and mitigate forecast risk,[258] to update and revise weather condition assumptions, and possibly to adjust transmission reliability margins.[259] EPRI contends that further studies are needed to determine a technical basis for updated wind speed assumptions and that such studies may take between one and two years.[260] Similarly, NERC asserts that the Commission should consider how variations in the temperature and load forecast should be addressed, what temperature sets should be used when considering requests to grant firm transmission service, and whether additional AAR calculation information should be incorporated into transmission line rating methodologies.[261]

109. Other commenters also discuss risk management for forecasted ambient air temperatures. For example, Entergy states that forecasted ambient air temperatures should include appropriate safety margins to account for historical forecast uncertainty.[262] Similarly, the SPP MMU states that, ideally, congestion costs should, to some extent, represent the risk assumed to serve the load.[263] Finally, the CAISO DMM argues that AAR requirements should allow leeway for RTOs/ISOs to adjust modeled transmission limits for reliability reasons, as CAISO does in the case of flowgates and nomograms whose modeled flows frequently differ from actual flows.[264] The CAISO DMM asserts that lower or more conservative transmission limits might be needed for temporally distant intervals to ensure commitments made in an advisory interval horizon are feasible in the binding market interval and at the time of power flow. The CAISO DMM further asserts that lower day-ahead transmission limits could promote the feasibility of day-ahead commitments in real time.[265]

110. Many RTOs/ISOs, however, oppose or urge caution on the proposed 10-day threshold, with many advocating instead for a 48-hour threshold.[266] PJM does not support use of AARs in ATC calculations beyond 48 hours, arguing that it would require significant system changes and increase the compliance burden.[267] PJM proposes AARs for 48 hours, and a more conservative approach for hours 48–240 to avoid potential volatility and over-selling.[268] Both NYISO and ISO–NE argue that the transmission service offered in their respective regions differs from that contemplated by the *pro forma* OATT, and request flexibility in implementing any transmission line rating requirements.[269]

111. NYISO does not support extending the AAR requirements or DLRs into the day-ahead market, or for use up to 10 days into the future, contending that such a requirement could result in costly and unnecessary uplift payments, which could lead to significant cost increases to customers, and could present reliability concerns if transmission line ratings decline in real time from the day-ahead schedule, forcing NYISO to rapidly reduce the schedules of certain generators while quickly ramping up other generators.[270] NYISO also states that it would consider designating a portion of transfer capability to be able to respond to the operational and cost volatility that would come with DLR use, although such a process would limit overall efficiency and increase production costs.[271]

112. Without taking a position on the proposed 10-day threshold, CAISO explains that the NOPR proposal would significantly increase the complexity of its day-ahead market and introduce possible variances between real-time and day-ahead schedules.[272] Also without taking a position on the proposed 10-day threshold, SPP states that, to use AARs to evaluate transmission service requests that end within 10 days or as the basis for curtailment, SPP would have to make several technical and process upgrades and align its operating horizon and planning horizon.[273]

113. MISO argues that the vast majority of the benefit from AARs is in addressing real-time congestion, and that implementing AARs in MISO's day-ahead market would be difficult to do in less than three years, while offering comparatively little benefit. MISO further claims that requiring hourly AARs 10 days in advance will provide little to no benefit because the accuracy of temperature forecasts diminishes considerably beyond 48 hours, and precipitously by the five to seven day mark.[274] MISO urges the Commission to limit AAR implementation to 48 hours from the start of the operating day.[275] Similarly, Potomac Economics recommends that the Commission require that AARs be used in the day-ahead and real-time markets, stating that this will allow the RTOs/ISOs to focus their resources on improving the transmission line ratings that will generate almost all of the savings.

114. Similar to RTOs/ISOs, transmission owners also urge caution on, or oppose, the proposed 10-day threshold.[276] Those transmission

[252] Industrial Customer Organizations Comments at 4–6.

[253] CEA Comments at 2.

[254] EDFR Comments at 7.

[255] ACPA/SEIA Comments at 16–17.

[256] Ohio FEA Comments at 5.

[257] OMS Comments at 11.

[258] EPRI Comments at 10–11.

[259] *Id.* at 12. Transmission reliability margin, or TRM, means 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. 18 CFR 37.6(b)(1)(viii) (2021)..

[260] EPRI Comments at 12.

[261] NERC Comments at 7.

[262] Entergy Comments at 11.

[263] SPP MMU Comments at 1.

[264] CAISO DMM Comments at 3, 4–5, 7.

[265] *Id.* at 3.

[266] PJM Comments at 7–8; ISO–NE Comments at 10; MISO Comments at 10, 16–17; NYISO Comments at 13–14.

[267] PJM Comments at 7–8.

[268] *Id.*

[269] ISO–NE Comments at 10; NYISO Comments at 9.

[270] NYISO Comments at 13–14.

[271] *Id.*

[272] CAISO Comments at 9–11.

[273] SPP Comments at 5–7, 9.

[274] MISO Comments at 18.

[275] *Id.* at 19.

[276] BPA Comments at 7; Indicated PJM Transmission Owners Comments at 2; Dominion

owners generally argue that there is too much risk forecasting 10 days forward and generally support more limited forecasting of either 24 [277] or 48 hours.[278] For example, Indicated PJM Transmission Owners contend that forecasting AARs beyond two or three days in advance provides little benefit because weather conditions beyond that are too difficult to predict.[279] Dominion similarly argues there is no benefit to extending the AAR requirements beyond three to five days because forecasts beyond five days tend to reflect seasonal averages.[280] Entergy contends that forecasts should be limited to three days and include appropriate safety margins for historical forecast uncertainty and geographic variability.[281]

115. Several commenters argue that requiring AARs 10 days in advance presents the potential problem of selling transmission service based on a given ambient air temperature forecast only for the temperature to be higher in real time, causing curtailments or safety and reliability risks.[282] BPA argues that it could result in an inefficient use of the transmission system because transmission could be sold, curtailed, and then available again, all prior to the transmission service window.[283] NYTOs note that, because there is generally less flexibility in real time, if operators do not have sufficient resources to restore flow to a lower limit within the required time, they may need to shed load or damage equipment.[284]

116. Arguing that the Commission should not extend the AAR requirements beyond the operating day, MISO Transmission Owners state that using AARs any further forward than in real time introduces uncertainty and error. MISO Transmission Owners acknowledge that these risks exist today, but argue that AARs introduce further complexity and explain that lowering transmission line ratings in real time would compound the problems.[285] Similarly, Duke Energy presents an example of transmission sold based on a 60 degree Fahrenheit temperature forecast four days forward and, on the operating day having the transmission system oversubscribed, with greater pressure on operators to curtail transmission schedules to avoid safety and reliability risks, because the actual temperature was 75 degrees Fahrenheit.[286] Southern Company states that AARs have the potential to create reliability concerns if transmission service is oversold due to inaccurate weather forecasts, especially for transmission service that is scheduled 10 days ahead.[287] Southern Company also states that reliability issues may arise because AARs may create difficulties in identifying the most limiting element, which may change as the temperature changes, for the purpose of complying with Reliability Standard FAC–008–5, and similar difficulties in complying with Reliability Standard PRC–023 relay loadability requirements that depend on maximum published ratings.[288]

117. NRECA/LPPC contend that such a requirement is unduly burdensome because most of the benefits of using AARs are for real-time and day-ahead transactions. NRECA/LPPC add that hourly weather forecasts and the resulting hourly transmission line ratings are unlikely to be accurate for more than a very few days.[289] IID explains that the Commission should provide flexibility in the forward AAR application period, noting that weather patterns may not be stable everywhere. IID contends that the Commission should consider implementation challenges associated with looking 10 days ahead, calculating what could be several hundred transmission line ratings per year.[290]

118. EEI and APS contend that AARs should only be implemented in real-time operations.[291] EEI contends that such AAR values should not extend to the day-ahead or intra-day unit commitment values and that hourly ATC for up to 10 days would introduce uncertainty and ATC fluctuations that result in curtailment of sold service and resale of previously curtailed service. EEI further explains that the Commission has previously recognized the reliability harm associated with overestimated ATC and explains that the harm may result from using hourly AARs for transmission service available for up to 10 days. EEI also states that the NOPR proposal for hourly ATC for every hour in the next 10 days is complex, with a burden that may outweigh the benefits since the NOPR proposal fundamentally requires a TTC determination. However, EEI states that TTC is path dependent and is based on many transmission line ratings, contingencies, and power flow assumptions. Because of this complexity, some transmission owners only determine TTC annually or less frequently and, for these transmission owners, the NOPR proposal for transmission providers to recalculate TTC every hour, and perform 240 calculations every hour, is infeasible.[292] NERC contends that the Commission should consider how entities should reconcile AARs used for planning and operations functions. NERC also argues that there is potential confusion regarding transmission line ratings used in transmission operator operations and planning system operating limits and interconnection reliability operating limits, but believes the confusion can be avoided through the timing of Commission action to retire the NERC Modeling, Data, and Analysis (MOD) A Reliability Standards.[293]

119. NYTOs explain that requiring AARs for up to 10 days forward, even for a subset of the transmission system, would be a significant change requiring major software buildout and corresponding market design changes, which would create a significant burden on NYISO and its associated utilities. NYTOs assert that this burden would be further complicated by the fact that vendor availability for such a buildout is unknown.[294] NYTOs also explain that implementing AARs 10 days forward has the potential to create reliability concerns through disconnects between forecasted and real-time conditions [295] and that extending the AAR requirements to the day-ahead market would make security analysis more difficult.[296] LADWP contends that the Commission should align any final rule requirements with NERC Reliability Standards and asserts that the proposed 10-day threshold would conflict with

Comments at 8–9; Duke Energy Comments at 8–9; SDG&E Comments at 2–3; Southern Company Comments at 5–6; MISO Transmission Owners Comments at 15–16; EEI Comments at 10–11; APS Comments at 8; NYTOs Comments at 5–6; AEP Comments at 6–7; NRECA/LPPC Comments at 19–20; SDG&E Comments at 2–3; LADWP Comments at 7; ITC Comments at 7–9.

[277] BPA Comments at 7; Duke Energy Comments at 8–9; Southern Company Comments at 5–6; MISO Transmission Owners Comments at 15–16; EEI Comments at 10–11; APS Comments at 8; NYTOs Comments at 5–6.

[278] AEP Comments at 6–7; NRECA/LPPC Comments at 19–20; SDG&E Comments at 2–3; LADWP Comments at 7.

[279] Indicated PJM Transmission Owners Comments at 2.

[280] Dominion Comments at 9.

[281] Entergy Comments at 11.

[282] MISO Transmission Owners Comments at 15–16; Duke Energy Comments at 8–9; Southern Company Comments at 5–6; NYTOs Comments at 5.

[283] BPA Comments at 7.

[284] NYTOs Comments at 5–6.

[285] MISO Transmission Owners Comments at 15–16.

[286] Duke Energy Comments at 8–9.

[287] Southern Company Comments at 5–6.

[288] *Id.* at 6.

[289] NRECA/LPPC Comments at 19–20.

[290] IID Comments at 4–6.

[291] APS Comments at 8; EEI Comments at 10–12.

[292] EEI Comments at 10–12.

[293] NERC Comments at 7–8.

[294] NYTOs Comments at 5–6.

[295] *Id.*

[296] *Id.* at 7.

the requirements specified in Reliability Standard MOD–001–1a that ATC be calculated hourly for the next 48 hours.[297] Moreover, recognizing the variability in weather, LADWP asks that system operators be afforded the flexibility to recall transfer capability awarded during moderate conditions at least 24 hours in advance.[298]

iii. Commission Determination

120. We adopt the NOPR proposal to require transmission providers to use AARs when evaluating the availability of and requests for near-term transmission service (under sections 15, 17, 18, and 29 of the *pro forma* OATT)[299] as set forth under ''Obligations of Transmission Provider'' in the *pro forma* OATT Attachment M adopted in this final rule. We further adopt the Commission's proposal in the NOPR to require transmission providers to use AARs as the relevant transmission line rating when determining whether to curtail or interrupt point-to-point transmission service (under sections 13.6 and/or 14.7 of the *pro forma* OATT) if such curtailment or interruption is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within the next 10 days. Additionally, we adopt the Commission's proposal in the NOPR to require transmission providers to use AARs as the relevant transmission line rating when determining whether to curtail network or secondary service (under section 33 of the *pro forma* OATT) or redispatch network or secondary service (under sections 30.5 and/or 33 of the *pro forma* OATT), if such curtailment or redispatch is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination (*i.e.,* the 10-day threshold). Finally, consistent with the NOPR, we clarify that AARs must be calculated using the temperature at which *there is sufficient confidence that the actual temperature will not be greater than that temperature* (*i.e.,* expected temperature plus an appropriate forecast margin).[300]

121. We believe that the 10-day threshold is justified by: (1) The additional benefits gained by adopting a threshold that permits weekly point-to-point transmission service requests to be evaluated using AARs; (2) the additional benefits gained by the use of daytime/nighttime ratings (discussed below in Section IV.B.2.c) within the 10-day threshold; (3) the adequate accuracy of ambient air temperature forecasts combined with the ability to implement appropriate forecast margins to alleviate operational concerns associated with persistently decreasing real-time transmission line ratings; and (4) the low relative cost difference between a shorter forward threshold and the proposed 10-day threshold. As the Commission stated in the NOPR, AAR requirements up to 10 days forward will permit weekly point-to-point transmission service to be evaluated using AARs. Because weekly point-to-point transmission service is one of several types of transmission products provided under the Commission's *pro forma* OATT, by adopting the 10-day threshold for AAR implementation rather than a shorter forward duration, weekly point-to-point transmission customers will receive the benefits of AAR implementation rather than only transmission customers taking shorter duration transmission service, thereby not just increasing the expected benefits from the implementation of AARs by improving the accuracy of transmission line ratings for a wider range of transmission services but also for a potentially wider range of transmission customers.

122. We also require AARs to include separate daytime and nighttime ratings. This daytime/nighttime ratings requirement, combined with the addition of weekly point-to-point transmission service, will produce further benefits in forward nighttime hours that would not see such benefits if the AAR requirements were imposed over a timeframe shorter than 10 days forward. These benefits of increased accuracy that result from applying daytime/nighttime ratings to weekly point-to-point transmission service and to shorter duration transmission service up to 10 days forward are significant on their own, even in the unlikely event that the use of ambient air temperature forecasts 10 days forward results in no hours where daytime AARs are greater than seasonal line ratings. In other words, if we were to adopt a shorter threshold for the AAR requirements than 10 days forward, the significant benefits derived from the more accurate transmission line ratings during the additional nighttime hours included in the 10-day threshold would be lost. We further note that weather forecast quality is not static, but rather is steadily improving such that the benefits of the 10-day threshold requirement are likely to increase over time.[301]

123. Although we acknowledge that the accuracy of forecasts decreases the further in advance the forecast is made, we disagree that ambient air temperature forecasts made 10 days in advance are so inaccurate that they cannot provide any benefits when used as part of AARs, even when adjusted with appropriate forecast margins, as discussed herein. Neither commenters supporting nor opposing the 10-day threshold provide quantitative evidence related to the accuracy of 10-day forecasts; however, a published analysis of the NOAA National Blend of Models (NBM) forecast—one of the publicly available NOAA forecasts that looks out at least 10 days—indicates that the mean absolute error for 240 hour (10 day) forward continental United States surface temperature forecasts was approximately four to six degrees Fahrenheit in July to November 2016.[302] We find that such levels of error would likely allow for a meaningful number of hours in any season where a 10-day forward AAR would provide benefits relative to the seasonal line rating. We also note that this finding is consistent with the support for the 10-day threshold by various commenters.[303]

124. We do not find persuasive arguments that the AAR requirements adopted in this final rule will be unduly burdensome. Contrary to such assertions, because we expect the increased costs of implementing AARs under a 10-day threshold (as opposed to a shorter threshold) to be primarily related to increased forecasting and data storage/hardware needs, we do not expect such costs to be excessive. Moreover, in certain situations, especially outside the RTO/ISO context, adopting the 10-day threshold will

[297] LADWP Comments at 7.

[298] *Id.* at 6.

[299] *See supra* P 85.

[300] *See* NOPR, 173 FERC ¶ 61,165 at PP 97, 102.

[301] *See, e.g.,* NOAA, *Annual WPC Mean Absolute Errors, https://www.wpc.ncep.noaa.gov/images/hpcvrf/maemaxyr.gif* (last visited Oct. 28, 2021) (showing NOAA data on the evolving accuracy of their Weather Prediction Center forecasts of daily high temperature).

[302] Tabitha Huntemann, Daniel Plumb, and David Ruth, *Verification of the National Blend of Models* (2017), *https://www.weather.gov/media/mdl/AMS2017-NBMVerification.pdf.* We note that this analysis was applicable to the 2016 National Blend of Models (NBM) Version 2.0 forecast, and that several improved versions of the NBM forecast have been implemented since that time. The current NBM Version 4.0 was implemented in September 2020. *See NBM: National Blend of Models, https://vlab.noaa.gov/web/mdl/nbm.* While we take notice of this NBM forecast accuracy data as a point of reference, we emphasize that the NBM forecasts are just one example of the types of forecasts that transmission providers might rely on in complying with this final rule.

[303] CEA Comments at 2; EDFR Comments at 7; Ohio FEA Comments at 5; New England State Agencies Comments at 9–10; ACPA/SEIA Comments at 13.

allow more transfer capability to be made available to customers than simply adopting seasonal worst-case assumptions. In addition, as CEA states, using AARs to calculate transmission line ratings for service requests up to 10 days has proven to be reliable and to provide benefits to effective and reliable transmission operations.[304] In that context, commenters have not provided evidence that the cost to procure or develop 10-day forward forecasts is materially different from the cost to procure or develop two- or three-day forward forecasts and, in any case, that such cost outweighs the added benefits of extending the forward period from two or three days to 10 days. For these reasons, we expect the material benefits resulting from adopting the 10-day threshold to, on balance, outweigh the costs.

125. We emphasize that any benefit from the AAR requirements, and the 10-day threshold in particular, should be compared to the relative costs of alternatives. And we find that the cost associated with requiring AARs for additional days forward is essentially the cost of accessing, storing, and processing the additional forecast data, and the cost of calculating, storing, and incorporating into transmission service the additional hours of AARs. As we expect this process will be largely automated, we do not anticipate that the cost of the 10-day threshold, as opposed to a shorter threshold, will be significantly higher. Although the question of where to draw the line in terms of the time threshold for AAR implementation is not clear cut, we find that 10 days strikes an appropriate balance between the benefits of more accurate transmission line ratings that result from the AAR requirements adopted in this final rule, and the likely costs of implementing those requirements.

126. We note that some commenters may have misunderstood the Commission's proposal in the NOPR as requiring the use of *expected* ambient air temperatures in forecasts of AARs for future periods. That is, they may have read the Commission's NOPR proposal as requiring that if the forecasted ambient air temperature at a given transmission line 10 days in advance (without any forecast margin applied, *i.e.,* the expected temperature) was X degrees, that the transmission provider was required to use an AAR for that hour 10 days forward that assumed an air temperature of X degrees. This is not the case. Rather, AARs must be calculated using the temperature *at which there is sufficient confidence that the actual temperature will not be greater than that temperature* (*i.e.,* expected temperature plus an appropriate forecast margin).[305] This approach to calculations is consistent with EPRI's recommendation and also comments from Entergy and the CAISO DMM, which suggest margins to account for forecast error.[306]

127. In response to requests for clarification from BPA, LADWP, and EEI that transmission providers can curtail transmission sold at least 24 hours in advance, consistent with existing curtailment prioritization, should temperature forecasts dictate such curtailment, we confirm that we are not changing the existing curtailment prioritization. In implementing the 10-day threshold, it may be necessary in some instances for transmission providers to curtail transmission sold based on ambient air temperature forecasts (including forecast margins) that end up being lower than real-time temperatures. Although transmission providers will continue to curtail transmission at times due to unrealized ambient air temperature assumptions, the need for such curtailments should be decreased as a result of the AAR requirements adopted herein.[307] We reiterate that under the AAR requirements that we adopt in this final rule, transmission providers have the latitude (and obligation) to develop accurate, safe, and reliable transmission line ratings,[308] and we do not expect that such transmission line ratings will necessitate an increase in the need for curtailments due to inaccurate AARs. If a transmission provider determines (whether during pre-testing of its AAR methodologies or during actual operations) that a given level of forecast margins yields an unreasonable frequency of such curtailment, it should re-evaluate and adjust its forecast margins.

128. We further acknowledge that, in addition to the concerns of some commenters related to forecast margins being too low, certain forecast margins could also prove to be too high. In those instances, as with the implementation of static transmission line ratings, 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. Similar to unreasonably low forecast margins, if a transmission provider determines (whether during pre-testing of its AAR methodologies or during actual operations) that a given forecast margin is unreasonably high, it should re-evaluate and adjust its forecast margins.

129. Similarly, contrary to comments from CAISO, NYISO, NYTOs, and EEI that describe the operational risks associated with overestimating ATC,[309] we do not expect that the AAR requirements adopted herein will result in a frequent number of instances when transmission line ratings used in the real-time market are lower than transmission line ratings used in the day-ahead market. Some such instances will occur, but we believe that there is sufficient latitude within our requirements, as discussed above, for day-ahead transmission line ratings to be determined with sufficient forecast margins to avoid this concern. Furthermore, as the Commission stated in the NOPR, day-ahead markets already rely heavily upon weather forecasts to inform next-day load and intermittent generation availability. This final rule does not change reliance upon weather forecasting; instead, the AAR requirements we adopt herein will improve the accuracy of transmission line ratings and, if anything, lead to cost savings to consumers and reliability benefits. Additionally, as PJM's AAR implementation experience demonstrates, temperatures can be forecast day ahead with a reasonable degree of certainty.[310] We also find that operational risks that might result from the use of transmission line ratings in the real-time market that are lower than the transmission line ratings used in the day-ahead market can further be

[304] CEA Comments at 2.

[305] *See* NOPR, 173 FERC ¶ 61,165 at PP 97, 102.

[306] EPRI Comments at 10–12; Entergy Comments at 11; CAISO DMM Comments at 3.

[307] We note, for example, that a typical winter seasonal line rating temperature assumption today is 32 degrees Fahrenheit—a temperature assumption which in many parts of the United States is violated frequently over the current typical six-month ''winter season'' used in seasonal line ratings. Commission Staff Paper at 7; *see also* Midwest Reliability Organization Standards Committee, *Standard Application Guide: FAC–008,* Version 1.1, p. 14 (March 21, 2017), *https://www.nerc.com/pa/comp/guidance/EROEndorsedImplementationGuidance/FAC-008-3%20Standard%20Application%20Guide.pdf.* We expect such assumption violations to be less frequent under our required approach, where transmission providers will apply reasonable forecast margins when developing their AARs

[308] NOPR, 173 FERC ¶ 61,165 at P 97.

[309] NYTOs Comments at 5–6; EEI Comments at 10–12; NYISO Comments at 13–14; CAISO Comments at 9–11.

[310] PJM Comments at 3.

managed and mitigated through the use of AARs in the RUC processes, which will have the benefit of updated temperature forecasts. Finally, we reiterate that PJM and AEP report reliability benefits from AAR implementation.

130. In response to comments from EEI and other transmission owners about the complexities of calculating AARs up to the 10-day threshold, we find that such complexities are predominately reflected in the upfront set-up and investment costs [311] and that these costs will be primarily related to increased forecasting and data storage/hardware needs.

131. In response to NERC's request that the Commission consider how entities should reconcile AARs used for planning and operations functions,[312] we find that AARs used in near-term operations will deviate from those transmission line ratings used in various planning functions. As transmission providers progress closer in time to a given interval, near-term ambient air temperature forecasts will necessarily be updated. These updates will impact TTC, and, as a result, ATC and system operating limits. In addition, regarding implementation of this final rule and currently effective MOD A Reliability Standards,[313] this final rule does not advocate for operating the transmission system beyond the system operating limits and established facility ratings.

132. In response to requests for clarification of the NOPR proposal from NERC and BPA with respect to temperature variations,[314] transmission providers must consider the relevant ambient air temperature forecasts along the transmission line, and determine the transmission line rating based on the most limiting combination of equipment limitations and forecasted local ambient air temperature along the transmission line. We note that NERC additionally requested that the Commission consider how variations in load forecasts would be addressed when using values for each of the 240 hours in the next 10 days for each transmission line in granting firm point-to-point transmission service.[315] In response, we reiterate that the requirements adopted herein are designed to ensure accurate transmission line ratings. We also reiterate that AARs must be calculated using the temperature *at which there is sufficient confidence that the actual temperature will not be greater than that temperature* (*i.e.,* expected temperature plus an appropriate forecast margin). We further clarify, in response to NERC, that transmission line rating methodologies must be updated. In particular, *pro forma* OATT Attachment M, as adopted by this final rule, requires transmission line ratings to be computed in accordance with a written transmission line rating methodology and consistent with good utility practice. Moreover, we note that Reliability Standard FAC–008–5 Requirement 3.2 requires transmission line rating methodologies to identify how ambient conditions are considered.[316] Thus, transmission line rating methodologies need to document methods used to calculate AARs.

133. In response to LADWP's argument that the Commission should align AAR requirements with the NERC Reliability Standards—and that the proposed 10-day threshold would conflict with the requirement specified in Reliability Standard MOD–001–1a that ATC be calculated hourly for the next 48 hours—we note that Reliability Standard MOD–001–1a requires that ATC be calculated for *at least* the next 48 hours, not for *only* the next 48 hours. Furthermore, the Commission's regulations require ATC to be calculated and/or posted for periods more than 48 hours in the future (*e.g.,* when transmission service is requested or inquired about).

134. Finally, in response to RTO/ISO requests for flexibility, we clarify the applicability of the 10-day threshold to RTOs/ISOs. The vast majority of energy transactions in RTOs/ISOs are executed and financially settled in the day-ahead and real-time energy markets; thus, we find that requiring AARs for the real-time and day-ahead energy markets in RTOs/ISOs is necessary to ensure the accuracy of transmission line ratings and just and reasonable wholesale rates. Because these transactions take place within a one-day forward timeframe, the 10-day threshold will provide very little additional benefits in existing RTO/ISO markets. Accordingly, the 10-day threshold will not apply to internal transactions or internal flows associated with through-and-out transactions in RTOs/ISOs. However, given that RTOs/ISOs generally use the *pro forma* OATT transmission service model for movement of electricity into/out of their service territories, the 10-day threshold requirement will apply to RTOs/ISOs' evaluation or determination of availability of transmission service at the seams of RTO/ISO service territories, in order to improve the accuracy of transmission line ratings and ensure just and reasonable wholesale rates.

b. Role of the Transmission Owner and Transmission Provider in AAR Implementation

i. NOPR Proposal

135. In proposing AAR implementation in the *pro forma* OATT, the Commission proposed for transmission providers—not transmission owners—to implement AARs because transmission providers—not transmission owners—must have an OATT.[317]

ii. Comments

136. Several commenters clarify that transmission owners, not transmission providers, calculate transmission line ratings.[318] For example, MISO states that its formational documents reflect, and have codified, the responsibility of transmission owners to calculate facility ratings, not MISO.[319] MISO Transmission Owners explain that Reliability Standard FAC–008–5 requires transmission owners to have ''a documented methodology for determining facility ratings of its solely and jointly owned Facilities'' based on the electrical characteristics of the transmission equipment or other industry standard.[320] Southern Company states that the MOD suite of NERC Reliability Standards governing TTC/ATC calculations requires transmission line ratings as provided by transmission owners.[321] Similarly, ISO–NE explains that its Transmission Operating Agreement requires its participating transmission owners to establish transmission line ratings for each transmission facility.[322] Additionally, NYISO states that in the New York Control Area, the transmission owners are responsible for developing transmission line ratings and providing the element ratings directly to NYISO. In turn, according to NYISO, NYISO determines the most limiting element, which sets the applicable facility rating.[323]

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[311] Exelon Comments at 8; AEP Post-Technical Conference Comments at 2–3; *see also supra* Section IV.B.1.c.

[312] NERC Comments at 6–7.

[313] *Id.* at 7.

[314] NERC Comments at 6–7; BPA Comments at 2–4.

[315] NERC Comments at 6–7.

[316] Reliability Standard FAC–008–5, Requirement R3.2, p.4, *http://www.nerc.com/pa/Stand/Project%20201803%20Standards%20Efficiency%20Review%20Require/2018-03__FAC-008-5__clean__01192021.pdf.*

[317] NOPR, 173 FERC ¶ 61,165 at P 84.

[318] MISO Comments at 27; Vistra Comments at 3–4; TAPS Comments at 13–14; Southern Company Comments at 6; EEI Comments at 2–4; MISO Transmission Owners at 29; EEI Comments at 2–4.

[319] MISO Comments at 27.

[320] MISO Transmission Owners at 29.

[321] Southern Company Comments at 3, 6.

[322] ISO–NE Comments at 6.

[323] NYISO Comments at 3.

137. Because of these differing transmission owner and transmission provider roles and responsibilities, these commenters request that the Commission recognize and make these differing roles explicit in any final rule.[324] Some recommend further Commission action to ensure transmission owners have an obligation to implement the AAR requirements in proposed *pro forma* OATT Attachment M. For example, Vistra encourages the Commission to modify its regulations to create a compliance obligation for each transmission owner to provide RTOs/ISOs all information necessary to implement proposed *pro forma* OATT Attachment M.[325] Similarly, TAPS requests that the Commission clarify that: (1) RTOs/ISOs have the authority to require transmission owners to provide the information they will need to implement AARs; or (2) transmission owners within RTOs/ISOs must provide the information RTOs/ISOs will need to implement AARs to the relevant RTO/ISO.[326] Additionally, TAPS argues that in order to achieve efficient and consistent application of AARs, the Commission should direct RTOs/ISOs to use, or at minimum accommodate the use of, ''look-up tables.''[327] TAPS explains that, using the ''look-up table'' approach will limit the obligation to continuously monitor weather reports to recalculate AARs and communicate those transmission line ratings to the RTO/ISO on an hourly basis.[328]

138. Noting the applicability of the *pro forma* OATT to transmission providers and that transmission owners and transmission providers are different in RTO/ISOs, Exelon comments on the phrasing ''is calculated'' in the AAR definition, explaining that, while it largely supports the proposed AAR definition, it does not ''calculate'' transmission line ratings hourly. Exelon states that it calculates 64 different transmission line rating cases (for nine temperatures sets, across normal, long-term emergency, short-term emergency, emergency load dump, and for both day and night), and then references the relevant existing calculations in a ''look-up table'' through its Inter-Control Center Communications Protocol signal. Exelon proposes to refine the AAR term to: ''a transmission line rating that reflects the appropriate temperature-adjusted rating for a facility based on an up-to-date forecast of ambient air temperatures across the time period to which the rating applies.''[329]

139. Finally, CAISO argues that RTOs/ISOs and their stakeholders will have to answer many questions in developing tariff provisions for using hourly transmission line ratings. Several of these questions relate to AAR implementation timelines, including the time hourly transmission line ratings must be submitted by the transmission owners to RTOs/ISOs and the time period that transmission owners will have to update hourly transmission line ratings for use in real-time markets after day-ahead results are published.[330] As an example, BPA explains that its dynamically established TTC calculations are based on schedules submitted 20 minutes before the operating hour.[331]

iii. Commission Determination

140. We clarify that transmission owners, not transmission providers, are responsible for calculating transmission line ratings. This responsibility is codified in the NERC Reliability Standards, as well as in RTO/ISO foundational documents.[332] Nothing in this final rule changes that responsibility. In the non-RTO/ISO regions, this detail is generally not a concern because the transmission provider is usually the transmission owner. However, in the RTO/ISO regions, there is a distinction between transmission owners and transmission providers. Thus, in order to comply with this final rule, RTOs/ISOs—the transmission provider with the OATT on file—will need to rely on their member transmission owners to calculate transmission line ratings and provide them to the RTO/ISO.[333]

141. In response to concerns about the responsibility for calculating transmission line ratings in RTOs/ISOs, we clarify that we expect RTOs/ISOs to require their member transmission owners to make timely calculations and determinations as required for transmission line ratings, and to provide them to the RTO/ISO.[334] Where the transmission provider is not the transmission owner (*e.g.,* RTOs/ISOs), we require the transmission provider to explain in its compliance filing, as part of its implementation of the new *pro forma* OATT Attachment M, through what mechanism (tariff, membership agreement, etc.) the transmission owner(s) will have the obligation for making and communicating to the transmission provider the timely calculations and determinations related to transmission line ratings (including the exercise of any discretion in calculations or application of exceptions).

142. In response to Exelon's concerns about the proposed AAR definition,[335] we clarify that hourly (or more frequent) querying of ''look-up tables'' or similar pre-calculated AAR databases will satisfy the requirement that AARs be calculated at least each hour. While we expect transmission owners to calculate transmission line ratings, given the difference between transmission owners and transmission providers in RTOs/ISOs, we require RTOs/ISOs on compliance to propose and justify a

[324] MISO Comments at 27; Vistra Comments at 3–4; TAPS Comments at 13–14; Southern Company Comments at 6; EEI Comments at 2–4.

[325] Vistra Comments at 3–4.

[326] TAPS Comments at 14.

[327] *Id.* at 8. TAPS states that, for each of their transmission facilities, transmission owners should be required to provide RTOs/ISOs with a table showing their temperature-adjusted rating for a pre-established set of ambient air temperatures.

[328] *Id.* at 8–10.

[329] Exelon Comments at 11–12.

[330] CAISO Comments at 12–13.

[331] BPA Comments at 5.

[332] *See, e.g.,* Reliability Standards FAC–008–5, Requirement R3 and FAC–008–5, Requirement R6.

[333] We note that, as discussed below, in RTO/ISO regions, in addition to AARs, transmission owners will be required to calculate and provide other transmission line ratings to the RTO/ISO, including seasonal line ratings and emergency ratings. Moreover, in RTO/ISO regions, transmission owners will be required to provide to the RTO/ISO the list of transmission lines which have been exempted from the AAR requirement (under the ''Exceptions'' paragraph of *pro forma* OATT Attachment M) or temporary alternate ratings (under the ''System Reliability'' section of *pro forma* OATT Attachment M).

[334] *See, e.g.,* MISO, MISO Rate Schedules, MISO Transmission Owner Agreement, art. 4, § II.A Providing Information (30.0.0) (''Each Owner and User shall provide such information to [MISO] as is necessary for [MISO] to perform its obligations under this Agreement and the Tariff.''); SPP, Governing Documents Tariff, Membership Agreement, § 3.5 Providing Information (0.0.0) (''Member shall provide such information to SPP as is necessary for SPP to perform its obligations under this Agreement and the OATT, and for planning and operational purposes.''); PJM, Rate Schedules, § 4.11 Transmission Facility Ratings (0.0.0) (''All Parties shall regularly update and verify Transmission Facility ratings, subject to review and approval by PJM, in accordance with the following procedures and the procedures in the PJM Manuals . . . .''); ISO–NE, ISO New England Inc. Agreements and Contracts, Transmission Operating Agreement, §§ 3.02(a)(ii) (5.0.0) (stating that ISO–NE shall ''determine Operating Limits based on forecasted or real-time system conditions and in accordance with the facility ratings established by the PTOs in collaboration with the ISO pursuant to Section 3.06''), 3.06(a)(v) (5.0.0) (stating that the transmission owner shall: ''(v) Collaborate with the ISO with respect to: (A) The development of Rating Procedures, (B) the establishment of ratings for each PTO's New Transmission Facilities; (C) the establishment of ratings for each PTO's Acquired Transmission Facilities that do not have an existing rating as of the Operations Date, and (D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date''); CAISO, CAISO eTariff, Transmission Control Agreement, § 4.2 (0.0.0) (stating that facility ratings are required CAISO's database of all facilities under the CAISO's control and that transmission owners are responsible for providing updates to that database when there is a change in ratings, which CAISO reviews).

[335] Exelon Comments at 11–12.

methodology for AAR implementation, delineating the expected roles between transmission owners and transmission provider. In doing so, we encourage RTO/ISO transmission owners to coordinate implementation methodologies and promote implementation consistency to the greatest extent possible within an RTO/ISO service territory. However, in response to comments from TAPS that the Commission should require use of a ''look-up table'' approach, or at least require that approach be an option,[336] we decline to require a specific AAR implementation methodology, noting regional software and procedural differences.

143. In response to requests for clarification from CAISO, we decline to require in this final rule a specific timeline by which AARs will need to be calculated or submitted to the transmission provider (either in the context of the day-ahead and real-time markets in RTOs/ISOs, or in terms of how far in advance of an operating hour an AAR should be calculated in a bilateral market).[337] However, we note that the AAR definition we adopt in this final rule requires that AARs ''[r]eflect[] an *up-to-date* [emphasis added] forecast of ambient air temperature across the time period to which the rating applies,'' by which we mean that new forecast data should be incorporated into AAR calculations as close to real time as reasonably possible given the timelines needed to obtain forecast data and perform the AAR calculation, as well as any other steps needed for validation, communication, or implementation of AARs.[338] Furthermore, transmission providers must explain their timelines as part of their compliance filings. We recognize that transmission providers already manage similar timing issues with respect to load forecasts, forecasts for renewable energy production, and generation bid deadlines, and it may be that deadlines for AAR calculation/submission are not significantly different from existing deadlines for submission of updates to generation supply offers and load.

[336] TAPS Comments at 7–10.

[337] We note that in some instances RTOs/ISOs may propose (as we understand PJM does now for its AARs) to have the RTO/ISO select AARs based on temperature forecasts and pre-calculated AAR tables/databases. In such cases, it may not be (as CAISO's comments suggest) that transmission owners will be sending entire sets of AARs to RTOs/ISOs every time they are calculated.

[338] *Pro Forma* OATT attach. M, AAR Definition.

c. Solar Heating in AAR Calculations

i. NOPR Proposal

144. In the NOPR, the Commission proposed to require AARs that reflect up-to-date forecasts of ambient air temperature, but noted that AARs could possibly incorporate other forecasted inputs.[339] As an example of other inputs, the Commission pointed to PJM's implementation of ''day and night ambient air temperature tables, where the night ambient air temperature table assumes zero solar irradiance.'' [340] The Commission also sought comment on whether to require transmission providers to implement DLRs, rather than only AARs, noting that DLRs can incorporate solar heating intensity, among other ambient conditions, to calculate the amount of transfer capability of a given transmission line in near real time.[341]

ii. Comments

145. Several commenters discuss the incorporation of solar heating into transmission line ratings. For example, Vistra suggests that, instead of requiring full DLRs, the Commission instead adopt a ''middle ground'' of requiring AARs that incorporate consideration of predictable solar heating (at least considering daytime/nighttime hours, similar to PJM's existing implementation of AARs).[342] Potomac Economics and Vistra contend that such a requirement would not necessitate sophisticated monitoring or forecasting, and instead would produce significant benefits with minimal cost.[343] R Street Institute, PG&E, Indicated PJM Transmission Owners, Dominion, and Potomac Economics also support incorporating predictable daytime/nighttime solar heating into AARs, with Dominion and Indicated PJM Transmission Owners noting that this is already the practice in PJM.[344] Entergy, without taking a position on whether it would be appropriate for the Commission to require separately calculated daytime and nighttime ratings, states that the shade of night provides an additional 5% to the transmission line's transmission line ratings.[345] PG&E states that it supports separately calculated daytime and nighttime ratings and indicates that its research from PJM's posted transmission line ratings shows that at least 14% of PJM's transmission line ratings would increase by 10% by considering solar heating.[346] Potomac Economics estimates that considering daytime/nighttime could increase thermal transmission line ratings on average by 11% during nighttime hours and the potential benefits would be approximately $30 million per year in MISO alone.[347]

146. Vistra points out that solar heating varies in several ways: Between daytime and nighttime (with sunrise/sunset times and day length varying significantly across the year), across the hours during the day (varying—under worst-case, clear-sky assumptions—from close to zero just after and before sunrise and sunset, respectively, to a daily mid-day peak), and across the days of the year (with higher mid-day peaks in the summer and lower peaks in the winter).[348] Vistra and PG&E both suggest that the Commission consider requiring regular updates to sunrise/sunset times, with Vistra discussing possible daily or seasonal updates, and PG&E discussing possible monthly updates.[349] Furthermore, while Vistra recommends that the Commission at the very least require separate daytime and nighttime AARs, Vistra also provides data for how solar heating varies significantly across the day, and discusses how more granular solar forecasting might reflect these solar variations.[350]

iii. Commission Determination

147. Upon consideration of the comments received in response to the NOPR, we require transmission providers to incorporate solar heating into AARs by implementing separate AARs for daytime and nighttime periods. Specifically, we require transmission providers to reflect the lack of solar heating in the technical assumptions for nighttime AARs. As noted by Dominion and Indicated PJM Transmission Owners, incorporating solar heating into AARs is consistent with PJM's existing AAR implementation.[351] Absent this requirement for daytime/nighttime

[339] NOPR, 173 FERC ¶ 61,165 at P 23.

[340] *Id.* P 23 n.40; *see also id.* P 21 (explaining that different types of ambient weather assumptions can be incorporated into transmission line ratings, including updated air temperature, solar irradiance, and wind speed, among others).

[341] *Id.* PP 25–26, 43.

[342] Vistra Comments at 4–5.

[343] *Id.* at 4–5; Potomac Economics Comments at 14–15.

[344] R Street Institute Comments at 3; PG&E Comments at 11–12; Indicated PJM Transmission Owner Comments at 8–9; Dominion Comments at 8; Potomac Economics Comments at 14–15.

[345] Entergy Comments at 8.

[346] PG&E Comments at 11.

[347] Potomac Economics Comments at 14–15.

[348] Vistra Comments at 4–6; *see also* PG&E Comments at 11–12.

[349] Vistra Comments at 5; PG&E Comments at 12.

[350] Vistra Comments at 4–5.

[351] Dominion Comments at 7–8; Indicated PJM Transmission Owners Comments at 7.

AARs, AARs would assume the worst-case solar heating assumptions in every hour, even at night when there is no solar heating of transmission lines at all.

148. The consideration of daytime/nighttime solar heating in the AARs used by transmission providers will further the Commission's goal of ensuring more accurate transmission line ratings, which result in just and reasonable wholesale rates. Furthermore, as commenters note, the improvements to the accuracy of transmission line ratings that will result from adopting a daytime/nighttime AAR requirement can yield significant economic benefits at minimal cost.[352]

149. We agree with commenters that sunrise/sunset times should be updated periodically to ensure the accuracy of both daytime and nighttime ratings. Specifically, we clarify that in order to comply with the requirement in *pro forma* OATT Attachment M for AARs to reflect the absence of solar heating during nighttime periods, transmission providers must update the sunrise and sunset times used to calculate their AARs at least monthly, if not more frequently. We find that among the daily, monthly, and seasonal timeframes suggested by commenters, the requirement to update sunrise/sunset times on a monthly basis strikes an appropriate balance between achieving the greatest benefits of AAR implementation and not imposing an unreasonable burden on transmission providers. Given the speed at which sunrise and sunset times change in many areas of the country during certain times of the year, monthly updates will result in significantly more accuracy in transmission line ratings and capture significantly greater value than seasonal updates. Because sunrise/sunset times can be easily calculated with precision based on location and day of the year,[353] and because we expect AAR implementation to be largely automated, we do not expect monthly updates to sunrise/sunset times to impose a significant additional implementation burden relative to seasonal updates. Nothing in this final rule would prevent a transmission provider from updating its sunrise/sunset times more frequently than monthly and we encourage transmission providers to do so.[354]

150. Vistra correctly points out that, in addition to sunrise/sunset times, solar heating also varies across the days of the year and the hours of the day. However, again, to maintain a balance of benefits and burdens, we decline to require regular updates to mid-day peak solar heating to account for differences across days of the year. As such, transmission providers may use maximum annual assumptions for solar heating when determining daytime AARs. Furthermore, to balance benefits and burdens, we decline to require more granularity (*e.g.,* hourly forecasts) in solar heating assumptions and only require daytime/nighttime consideration. We note, however, that nothing in this final rule would prohibit a transmission provider that wants to voluntarily implement regular updates to peak mid-day solar heating, or to voluntarily implement hourly forecasts for solar heating, from doing so. We further note that peak or hourly daytime solar heating (under worst-case clear-sky assumptions) can be accurately computed based on location using equations such as those presented in IEEE (Institute of Electrical and Electronics Engineers) Standard 738.[355]

3. Other AAR Implementation Issues

a. Reliability Unit Commitment Processes

i. NOPR Proposal

151. In the NOPR, the Commission proposed that RTOs/ISOs comply with the AAR requirements by revising their OATTs to implement AARs within their SCED and SCUC models (and in any relevant related models) in both the day-ahead and real-time markets and in any intra-day RUC processes.[356]

ii. Comments

152. CAISO requests clarification on whether hourly transmission line ratings should be constant in RUC processes.[357]

iii. Commission Determination

153. In response to CAISO, we clarify that transmission providers should propose on compliance to use updated AARs as part of any market process associated with the day-ahead and real-time markets (including RUC, as well as any look-ahead commitment processes or other such processes). In the event an RTO/ISO believes that AARs should not be used as part of any market process associated with the day-ahead and real-time markets (or that updated AARs should not be required for any market process), it should propose and justify such deviations on compliance.

b. Time Resolution and Calculation Frequency of AAR Requirements

i. NOPR Proposal

154. In defining AARs, the Commission proposed to require that AARs be calculated at least each hour, if not more frequently, and for AARs to apply to a time period of not greater than one hour.[358]

ii. Comments

155. Many state agencies, supply and load representatives, renewable energy advocates, and independent experts support the proposed AAR requirements overall, which includes the proposed time resolution or calculation frequency.[359] RTOs/ISOs are mixed in whether they take a position and generally discuss their ability to accept AARs calculated hourly. For example, while not taking a position on the appropriateness of this part of the NOPR proposal, MISO explains that its EMS and SCED are capable of receiving and leveraging AARs provided by their transmission owners at least hourly.[360]

156. CAISO explains that its transmission owners can submit AARs, but that the fundamental challenge with using AARs is timely communication of forecasted transmission line ratings. According to CAISO, participating transmission owners currently submit AARs as an equipment rating change through CAISO's outage management system (webOMS).[361] CAISO further states that using hourly adjusted transmission line ratings for transmission lines across the 24-hour horizon of a trading day will necessarily and significantly increase the complexity of CAISO's day-ahead optimization processes.[362] In addition, CAISO contends that hourly transmission line ratings in real-time markets may drive uplift costs by causing variances between total transfer

[352] Vistra Comments at 4–5; Potomac Economics Comments at 14–15.

[353] *See, e.g.,* National Oceanic and Atmospheric Administration, Global Monitoring Division, *General Solar Position Calculations, https://gml.noaa.gov/grad/solcalc/solareqns.PDF* (providing formulas for calculating sunrise/sunset times based on latitude, longitude, and day of the year).

[354] We note that PJM currently updates its sunrise/sunset times more frequently than monthly in its day/night AAR implementation.

[355] Institute of Electrical and Electronics Engineers, IEEE Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors 18–20, IEEE Std 738–2012 Cor 1–2013 (2013) (IEEE 738).

[356] NOPR, 173 FERC ¶ 61,165 at P 91.

[357] CAISO Comments at 12–13.

[358] NOPR, 173 FERC ¶ 61,165 at P 95.

[359] EPSA Comments at 2; Clean Energy Parties Comments at 2–3; R Street Institute Comments at 2–3; TAPS Comments at 1–3; ACORE Comments at 3; ACPA/SEIA Comments at 7; OMS Comments at 2; New England State Agencies Comments at 10; Vistra Comments at 2–3.

[360] MISO Comments at 12.

[361] CAISO Comments at 4.

[362] *Id.* at 9–10.

capability used in each of CAISO's commitment and dispatch processes. In addition, CAISO asserts that transmission line rating changes over the market run's look-ahead period can generate inefficient outcomes through deviations from day-ahead schedules.[363]

157. Similarly, NYISO cautions against requiring hourly updates to transmission line ratings if they are not already used by RTOs/ISOs.[364] NYISO explains that introducing hourly transmission line ratings could result in divergences from the day-ahead schedule, creating uplift or potential reliability risks, if hourly transmission line ratings cause a transmission line rating to decline.[365] On hourly updates to AARs, NYISO notes that its market software looks ahead, including a 24-hour day-ahead optimization and multi-period commitment for the real-time market.[366] NYTOs note that NYISO and NYTOs can apply AARs and DLRs to congested transmission lines currently in real time to increase transmission line ratings.[367]

158. ISO–NE states that it allows for short-term changes to transmission line ratings, though not at an hourly level.[368] ISO–NE further states that its coordinated transaction scheduling with NYISO runs every 15 minutes and therefore a shorter interval would have to be considered.[369]

159. While PJM supports the adoption of AARs, it opposes the requirements that a transmission line rating apply to a period not greater than one hour and that transmission line ratings be updated hourly. PJM states that the key factor for determining the transmission line rating is the temperature and, as a result, the primary event that triggers a change in AARs is the ambient air temperature. PJM states that, in implementing AARs, it continuously monitors temperatures and updates transmission line ratings for temperature fluctuations in accordance with the transmission owners' look-up table, so there is no benefit to updating the AARs hourly if no temperature change has occurred.[370] Relatedly, PJM and Duke Energy state that the proposed requirements in the NOPR that transmission line ratings be updated hourly could harm operations.[371] This is because, according to PJM, a significant temperature change could occur between required hourly updates and, if a transmission operator is not continuously monitoring ambient air temperature, an incorrect transmission line rating would be effective from the time of the temperature change until the next mandated hourly update.[372] PJM states that these temporal requirements simply add an administrative burden without providing additional benefits.[373] PJM requests that the Commission refrain from requiring transmission providers to apply AARs in hourly intervals but rather require them to be continuously monitored with changes triggered by temperature changes and the other relevant factors in the look-up tables.[374]

160. Many transmission owners also request flexibility on the proposed requirement for AARs to be calculated ''at least each hour.'' [375] ITC asks that the Commission instead only require daily AAR updates and notes that this is the prevailing practice for transmission owners using AARs in MISO.[376] MISO Transmission Owners also request flexibility to implement daily rather than hourly AARs.[377] Indicated PJM Transmission Owners argue against requiring hourly AAR calculations.[378] Indicated PJM Transmission Owners explain that PJM adjusts transmission line ratings over the day as temperatures change, but state that there is little benefit to hourly verification of temperature changes because transmission line ratings in PJM do not typically change hourly. Similarly, EEI argues for a requirement for daily AAR updates for real-time operations.[379]

161. In contrast, Entergy explains that it automatically updates AARs every hour for the approximately 1,000 facilities for which it calculates AARs, and this information is automatically updated hourly in Entergy's Real Time Contingency Analysis so the operator does not have to look at charts.[380] Exelon also contends that an hourly transmission line ratings check would not be overly burdensome and instead could help to prevent overloading a transmission line.[381] Exelon also urges the Commission to provide sufficient flexibility to ensure transmission line ratings can change intra-hourly.[382] Moreover, Exelon comments that it believes that the Commission's proposed requirements are sufficiently flexible to accommodate PJM's current approach.[383]

iii. Commission Determination

162. We adopt the Commission's proposal in the NOPR to require the calculation of AARs ''at least each hour, if not more frequently'' and the requirement that AARs ''appl[y] to a time period of not greater than one hour.'' [384]

163. With respect to calculation frequency, we believe that performing AAR calculations at least hourly appropriately balances requiring updates at a frequency that captures meaningful changes in ambient air temperature forecasts, and not overburdening transmission providers. In response to concerns that the requirement for hourly calculations may be unduly burdensome because temperature forecasts do not always fluctuate hour by hour, we recognize that in some hours forecasts for temperatures do not change, primarily because weather services do not always have updated forecasted values for every location each hour. However, it is not known exactly when such forecasted values will be updated, and, therefore, our requirement to calculate AARs hourly appropriately requires transmission providers to check for forecast updates and apply any updates that are available. We believe that the requirement to calculate AARs hourly ensures that any such publication of forecast updates are incorporated into AARs in a reasonable timeframe.[385] If we were to instead require such calculations on a longer time period (*e.g.,* every eight hours), then there would be some instances when published available weather forecast updates would not be incorporated into AARs in time to accurately reflect the transmission line's true transfer capability. Moreover, we expect this process for AAR implementation to be largely automated, with computer systems querying or receiving updated forecasts and processing any such data

[363] *Id.* at 10–11.
[364] NYISO Comments at 4.
[365] *Id.* at 4–5.
[366] *Id.* at 13.
[367] NYTOs Comments at 4.
[368] ISO–NE Comments at 6–7.
[369] *Id.* at 9.
[370] PJM Comments at 4–5.
[371] *Id.* at 5; Duke Energy Comments at 8.
[372] PJM Comments at 5.
[373] *Id.* at 2 n.5.
[374] *Id.* at 6.
[375] ITC Comments at 9; MISO Transmission Owners Comments at 24; EEI Comments at 12; Duke Energy Comments at 10.
[376] ITC Comments at 9.
[377] MISO Transmission Owners Comments at 24.
[378] AEP Comments at 6–7; Dominion Comments at 3; Indicated PJM Transmission Owners Comments at 7–9.
[379] EEI Comments at 12; PacifiCorp Comments at 2; BPA Comments at 3; WAPA Comments at 6–7.
[380] Entergy Comments at 3.
[381] Exelon Comments at 9–10.
[382] *Id.*
[383] *Id.* at 9.
[384] NOPR, 173 FERC ¶ 61,165 at P 3 n.3.
[385] For example, we understand that the NBM forecast (which is a blend of distinct constituent forecasts) has updates published at least every hour, but the constituent forecasts are typically updated only three times per day. Exactly when the constituent forecasts will be updated is not precise, such that an update to any forecasted value might change in any hour.

into updated AARs, such that calculating AARs hourly should not be significantly more burdensome than calculating AARs daily. We agree with Exelon that AAR calculations at least hourly are likely to be an important tool used to prevent any transmission overload that might occur as a result of a sudden, unexpected temperature increase.[386] We add that this requirement does not preclude intra-hour updates.

164. We acknowledge, in response to comments by CAISO and NYISO, that within RTOs/ISOs there will be times when AARs produce real-time transmission line ratings that diverge from what was previously calculated in the day-ahead market (based on earlier forecasts), and that this may result in operating considerations and uplift costs. However, we are not persuaded that such considerations or costs outweigh the benefits of updating real-time transmission line ratings discussed above. Further, updating transmission line ratings closer to real time will help ensure that the most accurate transmission line ratings are used in the real-time energy market and, in turn, tend to reduce costs and promote reliable operations. Commenters seem to argue that if the weather conditions unexpectedly change, such that temperatures are significantly lower and significantly more transfer capability is able to be used in real time compared to day ahead, the markets should keep such transfer capability in reserve in order to minimize uplift. We disagree that a concern about potential uplift should result in transfer capability being withheld from the real-time energy market with associated limits on the economic benefits of using AARs. Further, we do not believe that any operating considerations associated with updating transmission line ratings in real time will compromise reliable operations. As PJM states, AARs are already employed in PJM in both the day-ahead and real-time markets and, in its experience, AARs increase operational flexibility, promote a more efficient use of the transmission system, and result in more reliable system dispatch and cost-effective market operations.[387]

165. One of the reasons that substantial uplift is sometimes considered problematic is that it may be evidence that the market is not accurately considering operating constraints, which gives rise to out-of-market actions and distorts short-term and long-term price signals.[388] While we acknowledge the potential for uplift in certain situations, the reason for incurring uplift here is very different. Updating transmission line ratings in real time will result in more accurate prices that reflect actual real-time operating constraints. Accordingly, the potential for the generation of uplift through our AAR requirements would not be evidence of market design concerns or inaccurate price signals.

166. As discussed above, we believe that, under the AAR requirements adopted in this final rule, transmission providers will implement AARs with sufficient forecast margins in forward periods such that instances of reductions in transfer capability in real time and the related operational challenges will be infrequent. Accordingly, we anticipate that transfer capability will typically be freed up as forecasts become more certain (and require smaller forecast margins) from forward periods to actual operation, which will typically result in additional transmission being made available as we approach real time, and this will create some uplift. But we find this is the result of the policies that are needed to ensure transmission line ratings are sufficiently accurate to produce just and reasonable wholesale rates, and that any resulting uplift is, therefore, appropriate. Additionally, however, we acknowledge that transmission providers might also implement unreasonably high ambient air temperature forecast margins. In such instances, such unreasonably high forecast margins would need to be adjusted to ensure transmission line ratings are accurate.

167. We clarify that this final rule does not prohibit transmission providers from utilizing AARs that are calculated on a more frequent basis than hourly. Relatedly, in response to comments from PJM, we clarify that nothing in this final rule prevents a transmission provider from utilizing a transmission line rating calculated in between whatever standard AAR calculation period is established.

168. Turning to the hourly resolution (as opposed to the hourly frequency of calculation) of AARs, we adopt the NOPR proposal to require that AARs ''appl[y] to a time period of not greater than one hour'' because we find such a policy strikes an appropriate balance between providing sufficient granularity to transmission line ratings to reflect meaningful predictable changes in ambient air temperature across each day, and not overburdening transmission providers.[389] These changes are different from changes in ambient air temperatures discussed above, which are changes in forecasts due to improved information as a time period moves closer to real time as time advances.

169. We find that ambient air temperatures typically vary sufficiently across the day to produce meaningful differences in hourly transmission line ratings. For example, we expect temperatures during morning or evening hours to typically be significantly different than the noon temperature. Recognizing such temperature differences through transmission line ratings may be particularly important, since increasingly systems are being challenged during such morning or evening hours due to ramp or peak net load challenges. We find that hourly AAR calculations will create important additional operational flexibility for operators and more accurate transmission line ratings. And because we expect the AAR process to be largely automated, we do not believe that the requirement for hourly AARs will be significantly more burdensome than a less granular requirement (*e.g.,* a requirement that AARs apply to a time period of not greater than one day). In any event, we clarify that this final rule does not preclude a transmission provider from implementing AARs on a more granular basis than hourly, such as the 15-minute basis suggested by ISO–NE with respect to its coordinated transaction scheduling.

c. AAR Coordination

i. Comments

170. Several commenters argue that further consideration is needed on AAR implementation in certain circumstances.[390] For example, while not supporting or opposing an AAR mandate, NERC stresses the importance of reliability, explaining that reliability of the transmission system depends upon the proper coordination of transmission line ratings,[391] and states that special attention must be paid to reliability considerations in the implementation of any reforms in this proceeding.[392] Specifically, NERC notes that the Commission should consider whether to require transmission

[386] Exelon Comments at 9–10.

[387] PJM Comments at 2.

[388] *Uplift Cost Allocation and Transparency in Mkts. Operated by Reg'l Transmission Orgs. and Indep. Sys. Operators,* Order No. 844, 83 FR 18134 (Apr. 25, 2018), 163 FERC ¶ 61,041, at P 3 (2018).

[389] *Pro Forma* OATT attach. M, AAR Definition.

[390] NERC Comments at 6–7; EEI Comments at 14–15; NYTOs Comments at 7; CAISO Comments at 12–13.

[391] NERC Comments at 4.

[392] *Id.*

providers to coordinate AAR implementation methods since temperature readings and methodologies may differ on tie lines, and which transmission line rating should be used in the event of a disagreement among entities receiving transmission line ratings or methodologies.[393]

171. EEI asserts that the NOPR proposal was unclear about how AARs on transmission lines across seams should be determined, where transmission line ratings could be subject to assumptions from two different transmission providers, and how AAR compliance could be determined for non-jurisdictional transmission facilities. EEI urges flexibility on seams issues and for the Commission to enforce reciprocity conditions for non-jurisdictional entities, should the Commission require targeted AAR implementation.[394] IID also encourages the Commission to consider seams issues that may need to be addressed if AARs are different among neighboring utilities.[395] MISO Transmission Owners similarly state that ATC calculations on joint flowgates and tie lines between RTOs/ISOs will require coordination among all parties each time a transmission line rating changes, increasing the level of communication necessary. According to MISO Transmission Owners, along these joint flowgates and tie lines, transmission owners and RTOs/ISOs will need to decide which forecast will govern and whether to use multiple weather forecasts.[396]

ii. Commission Determination

172. We agree with NERC's comments stressing the importance of reliability and reiterate that system safety and reliability are paramount to the requirements for transmission line ratings that we adopt in this final rule. We agree with NERC and other commenters that implementation of AAR requirements on tie lines may necessitate increased communication among neighboring transmission providers and relevant transmission owners. While we expect that parties will work collaboratively to ensure that appropriate ratings are determined for each tie line, we decline to adopt specific requirements for coordinating AAR implementation across transmission provider seams. Parties along these seams have a long history of working collaboratively to ensure the reliable implementation of transmission facility ratings and we are not persuaded that specific requirements for coordination are required at this time. Moreover, we note that, in the event of a disagreement over the appropriate facility rating, the NERC Reliability Standards already establish a framework for how entities should proceed, *i.e.,* that the system should be operated to the most limiting parameter.[397] However, as described further in Section IV.G.3.b, to ensure that transmission providers have adequate transparency into the transmission line ratings methodologies of their neighbors, we require transmission providers to share transmission line ratings and transmission line rating methodologies with other transmission providers, upon request.

173. In response to EEI and NERC, we further clarify that, to the extent there is a disagreement among entities about the calculated AAR, transmission providers should use the most limiting AAR in order to ensure reliability and that thermal limits are respected. As IID suggests, however, if the most limiting AAR along a mutual seam is based on one transmission provider's ambient air temperature assumptions that are more risk averse than another transmission provider's ambient air temperature assumptions, the inevitable result will be increased congestion between control areas. While using the more risk averse transmission line rating may result in an increase in congestion relative to the alternative of using a lower forecasted ambient air temperature, we do not, in this final rule, revise each transmission provider's authority to set the transmission line ratings within its control area.

174. In response to EEI's request for clarification on the applicability of the AAR requirements to non-jurisdictional entities, we note that the Commission's *pro forma* OATT requirements apply only to Commission-jurisdictional transmission providers. However, to the extent non-jurisdictional entities have reciprocity tariffs on file with the Commission, such reciprocity tariffs will need to implement *pro forma* OATT Attachment M adopted herein in order to satisfy the Commission's comparability (non-discrimination) standards established in Order No. 888.

d. Applicability of AARs to Transmission Loading Relief (TLR) Events

i. NOPR Proposal

175. In the NOPR, the Commission proposed to require transmission providers to use AARs as the relevant transmission line rating when determining whether to curtail or interrupt point-to-point transmission service (under section 14.7 of the *pro forma* OATT) if such curtailment or interruption is necessary because of a reduction in transfer capability anticipated to occur (start and end) within the next 10 days. The Commission also proposed to require transmission providers to use AARs as the relevant transmission line rating when determining whether to curtail network transmission service or secondary service (under section 33 of the *pro forma* OATT) or redispatch network transmission service or secondary service (under sections 30.5 and/or 33 of the *pro forma* OATT), if such curtailment or redispatch is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination.[398]

ii. Comments

176. MISO states that the Commission should clarify that use of AARs in congestion management should not discriminate based on the type of flows being curtailed, be it transmission service or market flow, as some processes, such as the interregional TLR process, differentiate between the types of flow.[399]

iii. Commission Determination

177. We clarify that AARs should not discriminate based on the type of flows being curtailed, interrupted, or redispatched. Accordingly, we modify certain aspects of *pro forma* OATT Attachment M, as proposed in the NOPR, to clarify that AARs must be used as the relevant transmission line rating when determining whether to initiate TLR procedures anticipated to occur (start and end) within the next 10 days. We note that TLR procedures occur pursuant to the curtailment, interruption, and/or redispatch procedures outlined in *pro forma* OATT sections 13.6, 14.7, 30.5, and/or 33, which are also referenced in *pro forma* OATT Attachment M, as proposed in the NOPR, as requiring the use of AARs as the relevant transmission line rating.

[393] *Id.* at 6–7.

[394] EEI Comments at 14–15.

[395] IID Comments at 6–7.

[396] MISO Transmission Owners Comments at 32–33.

[397] Reliability Standard TOP–001–5, Requirement R 18, p. 7, *https://www.nerc.com/pa/Stand/Reliability%20Standards/TOP-001-5.pdf.*

[398] NOPR, 173 FERC ¶ 61,165 at PP 87, 89, 90.

[399] MISO Comments at 8.

In these instances, we find that proposed *pro forma* OATT Attachment M is already sufficiently clear: AARs must be used as the relevant transmission line rating when determining whether to initiate TLR procedures anticipated to occur (start and end) within the next 10 days. However, because *pro forma* OATT Attachment M, as proposed in the NOPR, only referenced curtailment and interruption procedures that occur pursuant to *pro forma* OATT section 14.7, for clarity, we modify the proposed *pro forma* OATT Attachment M to also reference curtailment and interruption procedures that occur pursuant to *pro forma* OATT section 13.6.

e. Communication and Verification of AARs

i. Comments

178. With regard to the Commission's NOPR proposal that AAR data be submitted by the transmission owner to the RTO/ISO through Supervisory Control and Data Acquisition (SCADA) or related systems, MISO states that it strongly urges the Commission not to require any specific data communication medium due to rapid and frequent changes in technology. MISO emphasizes that the scale and scope of AARs as proposed in the NOPR would require electronic and programmatic updates to the RTO/ISO, and using manual communication methods, such as phone calls or written messaging, would not be practical. MISO adds that the requirements to coordinate data interchange for reliability are currently regulated by the NERC Reliability Standards.[400] CAISO states that a fundamental challenge will be to ensure entities can transmit forecasted AARs in a timely manner.[401] As a result of this challenge, CAISO requests clarification on what to do in cases of communication failure between the transmission owner and the RTO's/ISO's EMS and what an RTO/ISO should do if a transmission owner submits an incorrect transmission line rating.[402] NYISO clarifies that it receives updates of transmission line ratings from asset owners via the Inter-Control Center Communication Protocol.[403] NYTOs explain that, since AARs and DLRs are constantly changing, independent software validation solutions will be needed to avoid violating NERC Reliability Standard FAC–008, which would occur when there is any accidental discrepancy between a calculated transmission line rating and the transmission line rating methodology.[404]

ii. Commission Determination

179. In response to comments requesting that the Commission not dictate communication mediums for transmission owners submitting AARs to RTOs/ISOs, we clarify that this final rule requires that electronic transmission line rating data be submitted by transmission owners directly into an RTO's/ISO's EMS through SCADA *or similar communication systems.* We clarify that other electronic systems, such as Inter-Control Center Communication Protocol, can be used to comply with this requirement, and RTOs/ISOs may propose to use such systems on compliance.

180. In response to concerns about potential scarcity of temperature data and/or AAR communication failures, we modify the NOPR proposal to require that, if an AAR otherwise required to be used under *pro forma* OATT Attachment M is unavailable, the transmission provider must use the relevant seasonal line rating as the appropriate transmission line rating. This requirement does not relieve any transmission provider of the obligation in the first instance to provide an AAR but provides an alternate only if an AAR otherwise required under *pro forma* OATT Attachment M is not available. Further, while this provision establishes the seasonal line rating as the default recourse rating, the transmission provider retains the ability under the ''System Reliability'' section of *pro forma* OATT Attachment M to use a different recourse rating where the transmission provider reasonably determines such a rating is necessary to ensure the safety and reliability of the transmission system.

181. In response to NYTOs' comments that changing transmission line ratings will necessitate additional transmission line rating validation tools, we reiterate that the definitions of Transmission Line Rating, AARs, and Seasonal Line Rating we adopt in this final rule—as set forth in *pro forma* OATT Attachment M—require computation of transmission line ratings in accordance with good utility practice, including up-to-date forecasts, to ensure the accuracy of the relevant transmission line rating.[405] And as NYTOs note, inaccurate transmission line ratings or a discrepancy between transmission line ratings and the transmission line rating methodology could trigger a violation of NERC Reliability Standard FAC–008 by the relevant transmission owner. In other words, *pro forma* OATT Attachment M imposes an affirmative obligation on transmission providers to implement accurate transmission line ratings and the NERC Reliability Standards similarly require accuracy in transmission line ratings by the transmission owners that calculate such ratings. In RTOs/ISOs, where the transmission provider (*i.e.,* the RTO/ISO) must rely on its transmission owners to calculate and provide the required transmission line ratings, we acknowledge that there might be some increased complexity in ensuring the accuracy of the transmission line ratings. However, we do not prescribe the method for a transmission provider—including an RTO/ISO—to screen for issues with transmission line ratings,[406] instead leaving it up to the transmission provider to develop a general validation system that ensures its compliance with the requirements of this final rule and relevant NERC Reliability Standards. We agree with MISO that it is unable—and indeed is not required—to audit transmission line ratings;[407] rather, the type of validation that we reference here would be akin to the automated validation referenced by CAISO, SPP, and PJM,[408] where the RTO/ISO runs checks for obvious signs of data errors or corruption.

182. In response to CAISO's request for clarification on what an RTO/ISO should do if a transmission owner submits an incorrect transmission line rating, we do not require RTOs/ISOs to audit or recalculate transmission line ratings submitted to them (except in instances where their procedures provide for them to calculate

[400] MISO Comments at 15–16.

[401] CAISO Comments at 4–5.

[402] *Id.* at 12–13.

[403] NYISO Comments at 4.

[404] NYTOs Comments at 7.

[405] *Pro Forma* OATT attach. M, AAR Definition.

[406] For example, a transmission provider might consider screening for such issues as: Missing data; significant changes in transmission line ratings; illogical data (such as ratings that increase with increasing temperature, or daytime ratings that are higher than nighttime ratings); and transmission line ratings outside feasible ranges for particular transmission lines.

[407] MISO Comments at 27.

[408] PJM Comments at 8; CAISO Comments at 13; SPP Comments at 5–6. We note that, according to the MISO Transmission Owners' Agreement (TOA), MISO also has a responsibility to verify transmission line ratings. MISO, Open Access Transmission, Energy and Operating Reserve Markets Tariff, Rate Schedule 1, Appendix B, Section V (30.0.0) (''Each Owner shall file with MISO information regarding the physical ratings of all of its equipment in the Transmission System. This information is intended to reflect the normal and emergency ratings routinely used in regional load flow and stability analyses. In carrying out its responsibilities, MISO shall apply ratings that have been provided by the respective Owners and have been verified and accepted as appropriate by MISO where such ratings affect MISO reliability.'').

transmission line ratings, such as for RTOs/ISOs that calculate AARs from tables or databases). To the extent any transmission provider becomes aware of an apparent inaccurate transmission line rating, the transmission provider is expected to inform the transmission owner immediately and both the transmission provider and transmission owner should take appropriate action to correct any inaccuracy. If the transmission provider and transmission owner are unable to resolve the inaccuracy of a submitted AAR, then, as discussed above, the transmission provider must use an appropriate recourse rating until the AAR inaccuracy is resolved. To the extent the transmission provider and/or transmission owner is out of compliance with any applicable requirements, they should report such noncompliance as dictated by the applicable requirement.

f. Minimum AAR Temperature Range and AAR Granularity

i. Comments

183. Vistra contends that the Commission should provide guidance on the range and granularity of temperatures to be used in AARs.[409] Vistra argues that the Commission's AAR policy will be undermined if implementation decisions reintroduce unnecessary conservativism (such as only altering AARs for every 20 degrees Fahrenheit of ambient air temperature, or developing AARs for only a limited range of ambient air temperatures).[410] Vistra suggests that it would not be unreasonable for AARs to change for every one or two degrees Fahrenheit change in ambient air temperature, and that AARs be calculated for a range of temperatures that cover the historical low and historical high temperature plus some margin (*e.g.,* 10 degrees).[411] Vistra argues that recent extreme temperature events illustrate that temperatures can exceed historical levels with important reliability implications.[412]

184. ITC asserts that the Commission should adopt a transmission line rating ''floor'' where no AAR would fall below the lowest seasonal line rating and states that operational risk and planning issues outweigh any benefit of exceeding such a floor given how rarely ambient air temperatures exceed those associated with the lowest seasonal line rating.[413]

ii. Commission Determination

185. In response to Vistra's comments, we clarify that any methods for determining AARs must be valid for at least the range of local historical temperatures (over the entire period for which records are available) plus or minus a margin of 10 degrees Fahrenheit, in order to meet the *pro forma* OATT Attachment M requirement that an AAR reflect an up-to-date forecast of ambient air temperature. For example, if the historical range is –30 degrees Fahrenheit to 107 degrees Fahrenheit, the valid range must be at least –40 degrees Fahrenheit to 117 degrees Fahrenheit. Where a transmission provider uses pre-calculated AARs within a look-up table or similar database, such values must be calculated for all temperatures within such a valid range. Similarly, where a transmission provider uses a formula or computer program to calculate AARs based on forecasted temperatures, such a formula/program must be accurate across such a valid range. Furthermore, transmission providers must have procedures in place to handle a situation where forecast temperatures fall outside of such a range of temperatures, to ensure that safe and reliable transmission line ratings are used. Finally, in the event that actual temperatures set new high or low records, transmission providers are required to revise their look-up tables/databases or formulas/programs, as necessary and within a timely manner, to maintain the 10 degree Fahrenheit margin.

186. We agree with Vistra's assertion that recent extreme temperature events in California and Texas illustrate that temperatures can exceed historical levels with significant economic and reliability implications.[414] The clarification that any methods for determining AARs must be valid for at least the range of local historical temperatures plus or minus a margin of 10 degrees Fahrenheit ensures that, when such severe and unexpected weather events do occur, transmission providers will be prepared and able to continue to implement more accurate transmission line ratings.

187. With respect to the requirement for AARs to reflects an up-to-date forecast of ambient air temperatures, as Vistra points out, absent clarification, some implementations of AARs may not result in an AAR change with every change in forecasted temperature (*e.g.,* implementations that use pre-calculated look-up tables or databases, where AARs do not change within each temperature ''step''). For this reason, we clarify that a transmission provider must implement AARs that update at least with every five degree Fahrenheit increment of temperature change, in order to meet the *pro forma* OATT Attachment M requirement that an AAR reflect an up-to-date forecast of ambient air temperature. For example, an AAR is not consistent with the requirements of *pro forma* OATT Attachment M if it results in transmission line ratings that do not change when temperature forecasts increase or decrease by five degrees Fahrenheit. This clarification is consistent with ERCOT's AAR implementation, which utilizes AAR look-up tables that define AARs in five-degree Fahrenheit steps.[415] We find that larger steps may introduce inaccuracies into transmission line ratings, resulting in wholesale rates that are unjust and unreasonable. Moreover, as Vistra suggests, a minimum amount of AAR temperature granularity is necessary to ensure that transmission line ratings sufficiently reflect changes in ambient air temperatures.[416]

188. We decline to require a transmission line rating ''floor'' whereby no AAR would fall below the lowest seasonal line rating, as requested by ITC. Seasonal line ratings are generally already calculated to reflect worst-case weather conditions. However, to the extent that a transmission provider experiences extreme temperatures that exceed seasonal assumptions, the resulting transmission line ratings will be more accurate than seasonal line ratings and will send important price signals to market participants. In such circumstances, transmission providers should be able to plan for such extreme temperatures given current temperature forecasting capabilities.

g. AAR Liabilities

i. Comments

189. Transmission owners also discuss and request protection from liabilities, which might result from AAR implementation. For example, explaining that using AARs in the day-ahead and/or real-time market may result in different congestion patterns than were anticipated, MISO Transmission Owners argue that transmission owners should not be responsible for any resulting uplift or for any impacts on the value of financial transmission rights (FTR) or the value of other market trades, uplift costs, or other losses resulting from the

[409] Vistra Comments at 6–7.

[410] *Id.* at 6.

[411] *Id.* at 6–7.

[412] *Id.* at 7.

[413] ITC Comments at 15–16.

[414] Vistra Comments at 6–7.

[415] Commission Staff Paper at 7.

[416] Vistra Comments at 6–7.

implementation of AARs. MISO Transmission Owners also contend that the Commission should absolve transmission owners from tariff violations resulting from last minute transmission line rating changes to protect public safety.[417]

190. Some commenters discuss the implications of the proposed *pro forma* OATT Attachment M for the FTR markets.[418] MISO and EEI also urge liability protections, explaining that absent liability protections, RTOs/ISOs and their members could be subject to liability if the weather is predicted incorrectly. MISO and EEI explain that implementing AARs in the day-ahead market could result in differences between the transmission line ratings used in FTR markets, and thereby impact the value of congestion rights. MISO and EEI further explain that if weather shifts unexpectedly, reliance on AARs could result in too much or too little being committed in the day-ahead market, causing financial impacts. MISO and EEI state that potential liability could also arise from possible reliability events for which it is subsequently determined that a more conservative transmission line rating could have prevented.[419] Explaining that in CAISO's congestion revenue rights (CRR) market ratepayers can be exposed to substantial losses after they become the CRR counterparty in the event some CRR auction capacity is left unpurchased, the CAISO DMM argues that transmission line ratings used in CRR auction models should still be the most conservative limits for those transmission lines instead of any higher limit enabled through hourly transmission line ratings.[420] The SPP MMU suggests that the implementation of AARs and DLRs should be coincident with an annual transmission congestion rights (TCR) auction, or the status of implementation should be clearly communicated to auction participants.[421]

191. ITC also asks that the Commission clarify that transmission owners will not be liable for any market inefficiencies that arise from inaccurate transmission line ratings, provided the transmission line ratings are communicated to the transmission provider in good faith.[422]

[417] MISO Transmission Owners Comments at 18–21.

[418] MISO Comments at 21; EEI Comments at 12; CAISO DMM Comments at 3–4, 8–9; SPP MMU Comments at 11.

[419] MISO Comments at 21; EEI Comments at 12.

[420] CAISO DMM Comments at 3–4, 8–9.

[421] SPP MMU Comments at 11.

[422] ITC Comments at 3.

ii. Commission Determination

192. We decline to provide explicit liability protections related to AAR implementation, as requested by commenters. We are not persuaded that this final rule's AAR reforms introduce additional liabilities that do not already exist. To the extent there are liability concerns associated with transmission line ratings changing in real time, these concerns already exist today as RTOs/ISOs forecast load and asset owners forecast renewable energy availability in real time. Moreover, FTR auctions, like all forward planning activities, already make a variety of forward assumptions about transmission availability that do not necessarily materialize in real-time operations. As the Commission stated in the NOPR, RTOs/ISOs already periodically request, and transmission owners periodically provide, *ad hoc* transmission line rating changes based on differences between actual and assumed ambient air temperatures.[423] In those cases, as long as utilities operate in a manner consistent with good utility practice, blanket liability protection is not necessary. Nevertheless, we note that transmission providers could submit filings pursuant to FPA section 205 to the Commission to propose revised liability protections in their tariffs to the extent they believe such protections are warranted.

C. Seasonal Line Ratings

1. Seasonal Line Ratings Requirements

a. NOPR Proposal

193. In the NOPR, the Commission proposed to require transmission providers to use seasonal line ratings when evaluating requests for other (longer-term) point-to-point transmission service, *i.e.,* requests for point-to-point transmission service ending more than 10 days from the date of the request. Specifically, the Commission proposed to require transmission providers to use seasonal line ratings as the relevant transmission line ratings when: (1) Evaluating requests for longer-term point-to-point transmission service; (2) responding to requests for information on the availability of such longer-term point-to-point transmission service (including requests for ATC or other information related to such potential service); and (3) posting ATC or other information related to such longer-term point-to-point transmission service to their OASIS site.

194. For network transmission service, the Commission proposed to require transmission providers to evaluate requests to designate network resources (under section 30 of the *pro forma* OATT) or network load (under section 31 of the *pro forma* OATT) based on seasonal line ratings because the Commission found that such designations are generally long-term requests and seasonal line ratings better reflect conditions over a longer term than AARs.

[423] NOPR, 173 FERC ¶ 61,165 at P 107.

195. The Commission further proposed to require transmission providers to use seasonal line ratings as the relevant transmission line ratings when determining whether to curtail or interrupt point-to-point transmission service (under section 14.7 of the *pro forma* OATT) in situations other than those in which such curtailment or interruption is necessary because of a reduction in transfer capability anticipated to occur (start and end) within the next 10 days. The Commission similarly proposed to require transmission providers to use seasonal line ratings as the relevant transmission line rating for determining the necessity of curtailment or redispatch of network transmission service or secondary service in situations other than those in which such curtailment or redispatch is necessary because of a reduction in transfer capability anticipated to occur within the next 10 days.[424]

b. Comments

196. Some commenters support[425] and others generally do not oppose the Commission's NOPR proposal to require transmission providers to use seasonal line ratings for transmission service requests and for curtailments, interruptions, and redispatch beyond the 10-day threshold. Some commenters argue that the Commission should go further by requiring that seasonal line ratings be used in transmission planning[426] and/or that more granular alternatives be used when examining transmission service involving wind resources.[427] CAISO and ISO–NE note that summer and winter seasonal line ratings are already used by transmission owners in their respective regions.[428] On the other hand, MISO Transmission Owners contend that the Commission should require seasonal line ratings in long-term transmission operations and planning only when it is beneficial to do

[424] *Id.* PP 88, 90.

[425] *See, e.g.,* AEP Comments at 1; EDFR Comments at 7.

[426] ACPA/SEIA Comments at 15–16.

[427] Clean Energy Parties Comments at 12.

[428] CAISO Comments at 3, ISO–NE Comments at 6.

so.[429] Similarly, Entergy argues that the Commission should not mandate the use of seasonal line ratings, explaining that it does not use seasonal line ratings, and that, instead, it uses AARs on a one-day, two-day, or hourly basis because AARs are more accurate. Entergy claims that maximum monthly temperatures in its service territory do not differ significantly enough for seasonal line ratings to create any value and therefore requirements to calculate seasonal line ratings would result in increased costs without commensurate benefits.[430]

197. SPP requests clarification on whether the seasonal line rating requirements are intended to apply to transmission service requests longer than one year in duration.[431]

c. Commission Determination

198. We adopt the Commission's proposal in the NOPR to require transmission providers to use seasonal line ratings as the appropriate transmission line ratings when: (1) Evaluating requests for transmission service—including point-to-point, network, and secondary service—ending more than 10 days from the date of the request; (2) responding to requests for information on the availability of such transmission service (including requests for ATC or other information related to potential transmission service); and (3) posting transmission availability (including ATC for point-to-point transmission service requests) or other information related to transmission service to their OASIS site.

199. Additionally, we adopt the Commission's proposal in the NOPR to require transmission providers to use seasonal line ratings as the relevant transmission line ratings when determining whether to curtail or interrupt non-firm point-to-point transmission service (under section 14.7 of the *pro forma* OATT) in situations other than those in which such curtailment or interruption is necessary because of issues related to flow limits on transmission lines anticipated to occur (start and end) within the next 10 days. We also require transmission providers to use seasonal line ratings when determining whether to curtail or interrupt firm point-to-point transmission service under section 13.6 of the *pro forma* OATT in such situations.

200. We also adopt the NOPR proposal to require seasonal line ratings be used as the relevant transmission line rating for determining the necessity of curtailment (under section 33 of the *pro forma* OATT) or redispatch (under sections 30.5 and/or 33 of the *pro forma* OATT) of network or secondary service in situations other than those in which such curtailment or redispatch is necessary because of issues related to flow limits on transmission lines anticipated to occur within the next 10 days. We continue to find that seasonal line ratings are the appropriate transmission line rating for evaluations of longer-term transmission service requests 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. The requirements for seasonal line ratings we adopt in this section are set forth under ''Obligations of Transmission Provider'' in *pro forma* OATT Attachment M.

201. In response to arguments from MISO Transmission Owners and Entergy that the Commission should not require seasonal line ratings or should do so only on a limited basis, we find that seasonal line ratings are needed to ensure that transmission line ratings used for evaluating requests for longer-term transmission service are accurate and result in just and reasonable wholesale rates. In response to Entergy's comment regarding its use of AARs instead of seasonal line ratings because AARs are more accurate, the seasonal line ratings requirements adopted herein do not prevent Entergy from using AARs for near-term transmission service, and in fact we require AARs to be used for near-term transmission service. Seasonal line ratings are only required to be used for longer-term transmission service. Entergy also claims that its maximum temperatures do not vary sufficiently across the year for seasonal line ratings to provide value. We find that, in general, temperatures vary sufficiently across seasons of the year for seasonal line ratings to provide value. We also find that the burden of implementing seasonal line ratings is particularly low.

202. In response to SPP's comments, we clarify that the requirements for seasonal line rating implementation do apply to transmission service requests longer than one year in duration. To the extent SPP's comments reflect any confusion about *how* to apply seasonal line ratings to service longer than a season, we clarify that such requests should be approved or denied (or availability should be determined) based on whether the requested service can be accommodated in each season (given the applicable seasonal line ratings).

203. We decline to adopt ACPA/SEIA's suggestion that seasonal line ratings should be required for transmission planning. Such a requirement is beyond the scope of this rulemaking, which is focused on remedying unjust and unreasonable wholesale rates resulting from inaccurate transmission line rating assumptions used in requests for transmission service and in transmission operations. We note that the Commission recently initiated a proceeding to examine a broad range of transmission-related issues, including regional transmission planning, in its July 2021 Advance Notice of Proposed Rulemaking in Docket No. RM21–17–000.[432]

2. Seasonal Line Rating Implementation Requirements

a. NOPR Proposal

204. In the NOPR, the Commission proposed to define a seasonal line rating in *pro forma* OATT Attachment M as ''a transmission line rating that: (a) Applies to a specified season, where seasons are defined by the transmission provider to not include more than three months in each season; (b) reflects an up-to-date forecast of ambient air temperature across the relevant season over which the rating applies; and (c) is calculated monthly, if not more frequently, for each season in the future for which transmission service can be requested.'' [433]

b. Comments

205. Many entities comment on the Commission's NOPR proposal to define ''seasonal line rating'' as a season which includes no more than three months. These entities predominately request flexibility for transmission providers to define seasonal line ratings in a manner appropriate to their climate.[434] For example, NRECA/LPPC contend that seasons do not fall into neat three-month windows and that shoulder months on either side of the summer season may resemble summer conditions more than fall or spring. For this reason, NRECA/LPPC recommend that the definition of seasonal line

[429] MISO Transmission Owners Comments at 17–18.

[430] Entergy Comments at 15.

[431] SPP Comments at 7.

[432] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 86 FR 40266 (July 27, 2021), 176 FERC ¶ 61,024 (2021).

[433] Proposed *pro forma* OATT attach. M, Seasonal Line Rating definition.

[434] NRECA/LPPC Comments at 23–24; MISO Transmission Owners Comments at 18; Entergy Comments at 15; SPP Comments at 8; EEI Comments at 9; ITC Comments at 9–10; MISO Comments at 20–21; SDG&E Comments at 3.

ratings be revised to accommodate regional considerations.[435] MISO Transmission Owners argue that the Commission should not require seasonal line rating durations to be limited to no more than three months because weather patterns vary widely.[436]

206. Duke Energy similarly states that temperatures in its Florida service territory do not differ enough to justify seasonal line ratings. Duke Energy also argues that, at a minimum, the Commission should clarify that one seasonal line rating set may have transmission line ratings equal to another seasonal line rating set, as long as the transmission line ratings are consistent with historically observed and/or expected weather patterns.[437] MISO states that requiring seasonal line ratings to be unique from season to season may introduce arbitrary differences in seasonal line ratings.[438]

207. ITC also asserts that the Commission should allow transmission owners to determine the number and length of seasons in their service territory so that seasonal line rating definitions may recognize differences in regional climates.[439] PacifiCorp states that it currently only uses summer and winter ratings and that implementation of the proposed three month seasonal requirements would require substantial expansion to its Weak Link databases.[440] PacifiCorp further states that firm contractual commitments may need to be reexamined and remedied if previously granted levels of transmission service cannot be honored under this seasonal line ratings construct.[441]

208. SPP notes that the three-month season duration conflicts with the four-month season length established by SPP's stakeholders.[442]

209. Other commenters question the proposed requirement for a ''seasonal line rating'' to ''forecast'' ambient air temperatures across the relevant season. SDG&E, for example, questions the value of basing seasonal line ratings for future seasons on weather forecast data, stating that such data is statistically insignificant that far into the future and instead suggests basing seasonal line ratings on historical weather data, specifically a 12-month, static data set per calendar month.[443] MISO Transmission Owners also state that the NOPR proposal would require seasonal line ratings to be based on forecasts, not historical data, as is currently used to develop seasonal line ratings.[444] MISO strongly urges the Commission to allow seasonal line ratings to be established based on historical data rather than forecasts because historical temperature data is known and thus more reliable than predictions. MISO contends that using forecast data would risk greater certainty.[445]

210. Finally, some commenters protest the proposed requirement for seasonal line ratings to be ''calculated monthly, if not more frequently, for each season in the future for which transmission service can be requested.'' Multiple commenters argue that this monthly updating requirement provides little value or can cause additional problems.[446] ITC argues that monthly updates to seasonal line ratings could cause significant uncertainty in planning processes and requests that the Commission instead only require seasonal line ratings be calculated for the duration of a single season.[447] Exelon explains that it does not update seasonal line ratings monthly, that its seasonal line ratings use historical temperatures to make assumptions on future maximum temperatures, and that those assumptions typically do not change. Exelon contends that there would not be any value in regularly reassessing seasonal line rating assumptions and instead suggests the following revision to the proposed definition of seasonal line rating: ''reflects a forecast of ambient air temperatures across the relevant season over which the rating applies.''[448] MISO, on the other hand, contends that seasonal line ratings, once established, should be reviewed when equipment changes are made, climate or weather data necessitates, or when otherwise prudent.[449]

c. Commission Determination

211. In response to comments requesting that the Commission provide flexibility for seasonal line ratings to cover periods greater than three months, we modify the Commission's proposed requirement in the NOPR for how transmission providers define seasons, to provide additional flexibility. Specifically, rather than prohibiting transmission providers from including more than three months in each season, we instead require that transmission providers define seasons to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent. Seasonal line ratings typically encompass six months. Six-month seasonal line ratings, however, necessarily require a worst-case weather representation specific to a specific month to be applied to every other month. In that context, ''summer'' seasonal line ratings could be, and often are, applied to the months of May through October despite the average historic high temperature in October, in much of the country, being considerably different than July's average historic high temperature. Moreover, ''winter'' seasonal line ratings could be, and often are, applied to the months of November through April despite the average historic high temperature in April, in much of the country, being considerably different than January's average historic high temperature. As with AARs, using unrealistic temperature assumptions will result in inaccurate seasonal line ratings, and, in turn, unjust and unreasonable wholesale rates.

212. However, we clarify that a transmission provider may define seasons shorter than three months, and/or have more than four seasons for its seasonal line rating program. For example, if a transmission provider found through its analysis that its system had a five-month ''summer'' period that was characterized by a consistent high temperature, that transmission provider could accommodate such a period by defining a three-month Summer 1 season, and a two-month Summer 2 season, and independently determining the seasonal line ratings (based on an independent analysis of temperatures) for each season. We further clarify, in response to comments from MISO, Entergy, and Duke Energy, that seasonal line ratings are not required to be arbitrarily different between seasons. As long as such ratings are *uniquely determined* in accordance with the relevant requirements, it is not prohibited for seasonal line ratings to be the same across different seasons if the independent analyses support those ratings, although we expect such instances will be infrequent.

213. In response to comments from PacifiCorp about the cost associated with implementing seasonal line ratings with three-month granularity, we appreciate that this three-month granularity requirement represents some level of burden, but we believe that the burden in most cases will be relatively low. Moreover, in cases such as

[435] NRECA/LPPC Comments at 23–24.

[436] MISO Transmission Owners Comments at 18.

[437] Duke Energy Comments at 12.

[438] MISO Comments at 20–21.

[439] ITC Comments at 9–10.

[440] PacifiCorp Comments at 3.

[441] *Id.* at 7.

[442] SPP Comments at 8.

[443] SDG&E Comments at 3.

[444] MISO Transmission Owners Comments at 34.

[445] MISO Comments at 21.

[446] Exelon Comments at 12–13; EEI Comments at 8–9; ITC Comments at 11; SDG&E Comments at 3.

[447] ITC Comments at 11.

[448] Exelon Comments at 12–13.

[449] MISO Comments at 21.

PacifiCorp describes, we believe that seasonal line ratings with a three-month granularity represent a more accurate representation of existing transfer capabilities and that using a more accurate representation of existing transfer capabilities will require transmission providers to more accurately examine the feasibility of existing contracts.

214. In doing so, our expectation is that, in at least certain circumstances, transmission providers will find that certain existing approved transmission service, accepted based on six-month winter seasonal air temperature assumptions of 32 degrees Fahrenheit (or other similar assumptions), are not able to be effectuated without curtailment, interruption, and/or redispatch, given likely warmer temperatures in shoulder periods falling within that six-month winter season.

215. In response to comments discussing the burden of calculating seasonal line ratings monthly, we modify the definition of seasonal line rating proposed in the NOPR to require that seasonal line ratings be calculated ''annually, if not more frequently,'' rather than ''monthly, if not more frequently.'' We adopt the remainder of the definition unchanged from the Commission's proposal in the NOPR. We agree with MISO that seasonal line ratings, once established, should be reviewed when equipment changes are made, climate or weather data necessitates, or when otherwise prudent. However, we also agree with commenters concerned about the burden of calculating monthly updates to seasonal line ratings and are persuaded that the underlying weather assumptions of seasonal line ratings are unlikely to change on a monthly basis. We believe that a requirement for annual recalculations of seasonal line ratings strikes an appropriate balance between ensuring seasonal line ratings continue to be accurate as weather patterns change,[450] and the costs associated with updating such transmission line ratings on a regular basis.

216. Finally, in response to comments that seasonal line ratings should be allowed to be based on historical temperatures, rather than forecasted temperature values, we clarify that seasonal line ratings may be derived from historical temperatures. Seasonal line ratings are an important input to longer-term sales for transmission service, and in that context are inherently forward-looking, but, given the challenges of forecasting future temperatures discussed in Section IV.b.2.a, seasonal line ratings may be based on historical temperatures, as long as such practices are consistent with good utility practice and otherwise meet the requirements in *pro forma* OATT Attachment M.

D. Exceptions and Alternate Ratings

1. NOPR Proposal

217. In the NOPR, the Commission proposed to require the use of AARs in many instances but allowed for the use of an alternative transmission line rating when a transmission provider determines that a transmission line is not affected by ambient air temperatures. Specifically, the Commission stated that not all transmission line ratings are affected by ambient air temperatures, either because the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperatures, or because the transmission line's transfer capability is limited not by ambient air temperatures but by a transmission system limit such as a system voltage or stability limit. For this reason, the proposed language under the ''Exceptions'' paragraph of *pro forma* OATT Attachment M accommodates such transmission lines without requiring unwarranted calculations or updates. Attachment M provides that, consistent with good utility practice, where the transmission provider determines that a transmission line is not affected by ambient air temperatures, the transmission provider may use a transmission line rating for that transmission line that is not an AAR or seasonal line rating.[451]

218. Additionally, the Commission proposed in the NOPR to include, in *pro forma* OATT Attachment M under the ''System Reliability'' section, a reliability ''safety valve.'' This exception provides that, if the transmission provider reasonably determines, consistent with good utility practice, that the temporary use of a transmission line rating different than would otherwise be required by *pro forma* OATT Attachment M is necessary to ensure the safety and reliability of the transmission system, then the transmission provider will use such an alternate transmission line rating.[452]

2. Comments

219. Several commenters state that certain transmission elements, such as underground cables, are not exposed to ambient air temperatures, and thus should be exempt from the AAR requirements.[453] For example, NYISO explains that many of its thermally limited transmission elements are underground cables.[454] While NYTOs note that NYPA and Consolidated Edison have piloted the use of DLRs on underground cables,[455] NYISO and NYTOs explain that underground cable ratings are typically the result of line-specific operating conditions (*e.g.,* thermal issues in the oil-filled pipe) and generally do not vary with ambient air temperatures.[456] For this reason, NYISO and NYTOs do not support AAR implementation on underground cables.[457] PJM and Eversource similarly request an exception from the proposed AAR requirements for underground cables, noting that their ratings are not affected by ambient air temperatures.[458]

220. NYTOs and NRECA/LPPC contend that AARs may not be appropriate on older transmission facilities.[459] For example, NRECA/LPPC assert that a transmission provider should be allowed to obtain a waiver from the AAR requirements when implementation would be too difficult or costly, noting that this may especially be the case for older transmission facilities.[460] Relatedly, EEI includes asset health as one consideration that might be taken into account by transmission owners in their recommendation for transmission owners to study AAR implementation and propose candidate AAR transmission lines.[461]

221. NRECA/LPPC contend that the AAR requirements should not apply to transmission lines that are not part of the bulk electric system operated above 100 kV.[462] Entergy similarly contends that AARs should not be required on facilities operated at or below 69 kV stating that such facilities are more likely to include underbuilds, such as

[450] ACPA/SEIA Comments at 8, 11; EPSA Comments at 4; New England State Agencies Comments at 6.

[451] NOPR, 173 FERC ¶ 61,165 at P 103.

[452] Proposed *pro forma* OATT attach. M, ''System Reliability''.

[453] *See, e.g.,* NYISO Comments at 8–9; NYTOs Comments at 8; PJM Comments at 6; LADWP Comments at 8.

[454] NYISO Comments at 8.

[455] NYTOs Comments at 4.

[456] NYISO Comments at 4; NYTOs Comments at 8.

[457] NYISO Comments at 8–9; NYTOs Comments at 8.

[458] PJM Comments at 6; Eversource Comments at 3.

[459] NYTOs Comments at 7; NRECA/LPPC Comments at 22.

[460] NRECA/LPPC Comments at 22.

[461] EEI Comments at 7.

[462] NRECA/LPPC Comments at 17.

third-party telecommunications facilities, and that, as a result, the use of AARs on such facilities could have significant third-party effects.[463] EEI includes voltage levels as another consideration that might be taken into account by transmission owners in their recommendation for transmission owners to study AAR implementation and propose candidate AAR transmission lines.[464]

222. LADWP requests flexibility in the implementation of AARs, noting high wind speeds in California increase wildfire risk and that it may be preferable to allow transmission line loadings to fall in those circumstances.[465] PG&E, in proposing criteria for determining candidate transmission lines for AAR implementation, identifies wildfire risk and transmission lines within high fire threat districts as transmission lines that specifically may not be considered for AAR implementation.[466] EEI includes wildfire areas as another consideration that might be taken into account by transmission owners in its recommendation for transmission owners to study AAR implementation and propose candidate AAR transmission lines.

223. CAISO, SDG&E, and SCE also note challenges or the potential inapplicability of AARs to certain transmission lines under remedial action schemes.[467] Given the challenges of applying AARs to remedial action schemes designed to prevent thermal overload, CAISO requests clarification on whether transmission lines whose thermal ratings trigger remedial action schemes should be rated using AARs.[468] SCE explains that applying AARs to remedial action schemes, which are facility-rating dependent, may adversely impact the protection scheme, potentially increasing operational complexity, and could potentially initiate a widespread chain of additional reliability considerations that would require evaluation and potential mitigation.[469] SDG&E also explains that it has flow-based remedial action schemes which use facility ratings to operate and are set to operate at a static value. According to SDG&E, all of these characteristics will cause AARs to yield no benefit to the monitored facilities and that removing this limitation will increase the complexity of the remedial action scheme.[470]

224. ISO–NE and NYISO also discuss remedial action schemes.[471] NYISO discusses corrective action plans, which create plans to respond to contingencies, and voices concern that frequently updated transmission line ratings, especially an update that lowers transmission line ratings, would have a detrimental effect on reliability should the system operating limits used to develop the corrective action plan in planning studies not materialize in real time.[472] ISO–NE requests that transmission lines where the actions or triggers of a remedial action scheme are based on a transmission line rating be exempt from any AAR requirement, noting that use of AARs on these transmission lines may require installing transmission system upgrades.[473]

225. Exelon and EEI support the NOPR's proposed exceptions but request that the applicability of the exceptions be determined by the transmission owner, not the transmission provider.[474] Exelon contends that because the NERC Reliability Standards give the transmission owner responsibility for establishing transmission facility ratings, the transmission owner should be the entity that decides when one or more of the exceptions apply.[475]

226. Finally, EPSA asks that transmission providers be required to disclose (potentially via OASIS) which transmission lines they deem as not benefitting from an AAR or seasonal line rating. EPSA also asks that transmission providers be required to disclose the reasons for making those determinations to thereby enable RTOs/ISOs and market monitors to verify those decisions. Moreover, EPSA asks that these decisions be evaluated at least every five years to ensure AAR-exempt transmission lines should continue to qualify for exceptions.[476]

3. Commission Determination

227. As set forth in *pro forma* OATT Attachment M, we adopt the NOPR proposal to allow exceptions to the AAR and seasonal line rating requirements in instances where the transmission provider determines, consistent with good utility practice, that the transmission line rating of a transmission line is not affected by ambient air temperatures.[477] In this instance, the transmission provider may use a transmission line rating for that transmission line that is not an AAR or seasonal line rating. Examples of such a transmission line may include (but are not limited to): (1) A transmission line for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperatures; or (2) a transmission line whose transfer capability is limited by a transmission system limit (such as a system voltage or stability limit) which is not dependent on ambient air temperatures. As discussed in the NOPR, we adopt this exception because not all transmission line ratings are affected by ambient air temperature, either because the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature, or because the transmission line's transfer capability is limited by a transmission system limit (such as a system voltage or stability limit) which is not dependent on ambient air temperature.[478]

228. We also adopt the NOPR proposal to establish a ''System Reliability'' section in *pro forma* OATT Attachment M that will allow a transmission provider to temporarily use a transmission line rating different than would otherwise be required under *pro forma* OATT Attachment M in instances when the transmission provider reasonably determines, consistent with good utility practice, that the use of such a temporary alternate rating is necessary to ensure the safety and reliability of the transmission system.[479] As discussed in

[463] Entergy Comments at 10–11.

[464] EEI Comments at 7.

[465] LADWP Comments at 6–7.

[466] PG&E Comments at 5.

[467] SCE Comments at 4; SDG&E Comments at 4; CAISO Comments at 12–13.

[468] CAISO Comments at 12–13.

[469] SCE Comments at 4.

[470] SDG&E Comments at 4.

[471] NYISO Comments at 7–8; ISO–NE Comments at 9.

[472] NYISO Comments at 7–8.

[473] ISO–NE Comments at 9.

[474] Exelon Comments at 2; EEI Comments at 6.

[475] Exelon Comments at 11.

[476] EPSA Comments at 4.

[477] As discussed in Section IV.B.2.b, we clarify that transmission owners, not transmission providers, are responsible for calculating transmission line ratings. However, in the RTO/ISO regions where there is a distinction between transmission owners and transmission providers, we clarify that we expect RTOs/ISOs to require their member transmission owners to make timely determinations on transmission line rating exceptions, and to provide them to the RTO/ISO. In such instances, we require the transmission provider to explain in its compliance filing, as part of its implementation of the new *pro forma* OATT Attachment M, through what mechanism (tariff, membership agreement, etc.) the transmission owner(s) will have the obligation for making and communicating to the transmission provider the timely determinations related to transmission line ratings exceptions.

[478] NOPR, 173 FERC ¶ 61,165 at P 103.

[479] Because the ''System Reliability'' section provides an exception and does not establish a requirement, we change the verb tense in this section to indicate that in such circumstances, the transmission provider *may* use an alternate transmission line rating rather than stating that the

Continued

the NOPR, while we expect that such alternate transmission line rating authority would be needed infrequently, if ever, we adopt the ''System Reliability'' section of *pro forma* OATT Attachment M to resolve any instance where a transmission provider reasonably believes that the requirements for transmission line ratings conflict with system safety or reliability.[480]

229. We decline to adopt the further specific exceptions requested by commenters. First, with respect to underground cables, as multiple commenters note, the transfer limit of underground cables is generally not affected by ambient air temperatures. Rather than adopting a blanket exception for underground transmission lines, we note that where the technical transfer limits of such cables are not affected by ambient air temperatures, they would satisfy the exception for instances in which the transmission line rating of a transmission line is not affected by ambient air temperatures. Because the transmission line ratings for underground transmission lines are generally the result of thermal issues in the oil-filled pipe, we agree with commenters that underground transmission lines likely satisfy such exception.

230. With respect to older transmission facilities, we decline to adopt an exception from the AAR requirements for such facilities. We do not find the arguments that these facilities cannot be rated using AARs persuasive. For one, Reliability Standard FAC–008–5, which sets forth requirements to ensure that transmission line ratings used in operations are determined on a technically sound basis, makes no distinction with respect to age of transmission lines: Ratings for all transmission lines must be based on technically sound principles outlined in the Reliability Standard.[481] Moreover, regardless of transmission facility age, the principles of transmission line sag and tension are correlated with the conductor material and construction style. A conductor's sag, tension, and swing properties are used to calculate clearances to vegetation, structures, and other distribution/communication lines. For older transmission lines that do not have computerized sag/tension values, graphical methods can be used to generate the values.[482] These values for older transmission lines, similar to parameters for new facilities, are used to calculate transmission line ratings and adjust transmission line ratings based on various operating/ambient air temperatures.

231. Third, we decline to adopt a blanket exception from the AAR requirements for transmission facilities below a specific voltage threshold. Commenters have not explained why transmission line ratings from lower voltage transmission facilities cannot be rated using AARs. Rather, we find that the same principles and factors determining transmission line ratings for higher voltage transmission lines apply to lower voltage transmission line ratings. We further note that within RTOs/ISOs (and possibly in other areas), lower voltage transmission lines often represent the binding transmission constraints that cause congestion, because such lines are at their limits within the modeled contingencies, and so we expect that excluding such transmission lines would meaningfully reduce the benefits of AARs. However, in response to Entergy's comments,[483] we note that in cases where lower voltage transmission facilities might host third-party under-build, such under-build can and should be considered when developing the sag limits that inform a transmission facility's AARs.

232. Fourth, we decline to adopt a blanket exception for nomogram facilities, for transmission facilities that are part of certain remedial action schemes, or for transmission facilities in areas at risk of wildfires. For nomogram constraints, as noted in Section IV.B.1, these typically occur to protect system stability or voltage and the AAR requirements adopted herein exempt such transmission lines as well as those whose transmission line ratings that are not affected by ambient air temperatures. We also note that remedial action schemes are not inherently inconsistent with AAR implementation. For example, PJM implements both AARs and remedial action schemes.[484] In any event, if the transmission owner determines that the transmission line ratings of transmission lines associated with the remedial action schemes are not affected by ambient air temperature because the operational limitations of the remedial action scheme represent the relevant limiting element, then the ''Exceptions'' paragraph of *pro forma* OATT Attachment M would apply. Moreover, the transmission provider may also utilize the ''System Reliability'' exception of *pro forma* OATT Attachment M if the reasonably transmission provider determines, consistent with good utility practice, that the temporary use of a transmission line rating different than would otherwise be required under *pro forma* OATT Attachment M is necessary to ensure safety and reliability. While we note the various exceptions to AAR implementation that may be applicable to remedial action schemes, we expect that, in situations where the remedial action scheme is not armed, transmission providers will implement the AAR requirements unless doing so would negatively impact system reliability. Finally, to mitigate the risk of wildfires, we reiterate our adoption of the ''System Reliability'' exception in *pro forma* OATT Attachment M to ensure the safety and reliability of the transmission system. We believe this exception provides sufficient flexibility for transmission providers to use seasonal or static line ratings when reliability and good utility practice call for it.

233. As suggested by EPSA,[485] we modify proposed *pro forma* OATT Attachment M to require transmission providers to reevaluate any exceptions taken under the ''Exceptions'' paragraph of *pro forma* OATT Attachment M at least every five years to ensure that longstanding exceptions continue to be valid. However, we clarify that if the technical basis for such an exception goes away, the transmission line must be re-rated in a timely manner,[486] and that the five-year reevaluation requirement is just to ensure that any exceptions do not inadvertently grow

transmission provider ''will use'' an alternate transmission line rating as was proposed in the NOPR.

[480] NOPR, 173 FERC ¶ 61,165 at P 97.

[481] In addition to the Reliability Standard, the NERC alert in 2010 recommended that transmission owners conduct an assessment and perform any necessary remediation of rating issues including review of the current facility ratings methodology for their solely and jointly owned transmission lines to verify that the methodology used to determine facility ratings is based on actual field conditions with no distinguishment due to age of transmission assets.

[482] *See, e.g.,* ''*Sag-Tension Calculation Methods for Overhead Lines,*'' CIGRE Task Force B2.12.3 (Apr. 2016); ''*Graphic Method for Sag Tension Calculations for ACSR and Other Conductors*,'' Publication No. 8, Aluminum Company of America (1961).

[483] Entergy Comments at 10–11.

[484] For example, PJM Manual 3: Transmission Operations, Attachment A, provides a listing of the remedial action schemes in operation in PJM. PJM Manual 3 is available here: *https://pjm.com/-/media/documents/manuals/m03.ashx.*

[485] EPSA Comments at 4.

[486] The definition of transmission line rating we adopt in *pro forma* OATT Attachment M requires that transmission line ratings reflect the relevant technical limitations. Thus, when technical limitations that would justify an exception go away, that transmission line rating would need to be properly rated in a timely manner to continue to comply with the *pro forma* OATT.

stale (*i.e.,* the five-year reevaluation is not a justification for waiting five years to re-rate a transmission line). We do not specifically require a periodic re-evaluation of temporary alternate ratings, as we expect such ratings to be used over relatively short timeframes. However, we note that temporary alternate ratings may only be used during periods in which the transmission provider determines that they are necessary under the ''System Reliability'' section of *pro forma* OATT Attachment M.

234. Finally, as further discussed below in Section IV.G.3.d, we modify proposed *pro forma* OATT Attachment M to require that uses of exceptions or temporary alternate ratings under *pro forma* OATT Attachment M be posted to OASIS or another password-protected website. We require that such postings document the nature of and basis for each such exception or alternate rating, as well as the date(s) and time(s) of initiation and (if applicable) withdrawal for the exception or the alternate rating. Further, transmission providers must maintain in such databases records of which transmission line ratings and methodologies were in effect at which times over at least the previous five years. This five-year period of record retention is consistent with a majority of the document retention periods required for OASIS postings.[487]

E. Dynamic Line Ratings

1. Dynamic Line Ratings Definition

a. NOPR Proposal

235. In the NOPR, the Commission proposed to define a dynamic line rating as 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, transmission line tension, or transmission line sag.[488]

b. Comments

236. Comments on the proposed definition were limited; however, Industrial Customer Organizations ask that the proposed definition be expanded to include additional inputs, such as conductor temperature, thermal age of the line, and the cumulative number and frequency of faults. Industrial Customer Organizations assert that thermal age of a transmission line is a more accurate measure of a transmission line's physical capability than calendar age.[489]

237. Noting that the Commission proposed to require AARs when evaluating requests for short-term transmission service and when considering potential curtailment, interruption, and/or redispatch expected to occur in the next 10 days, ACPA/SEIA argues that DLR implementation should also fulfill the AAR requirements in proposed *pro forma* OATT Attachment M.[490]

c. Commission Determination

238. We adopt the definition of DLR that the Commission proposed in the NOPR. We believe that this definition clearly sets forth a non-exhaustive list of factors affecting transmission line ratings to be input into calculations of DLRs. There are many factors that affect an individual transmission line rating; for this reason, it would be inappropriate for the Commission to attempt to create an exhaustive list of factors affecting transmission line ratings for inclusion in the definition of DLR.

239. In response to arguments from ACPA/SEIA, we clarify that because the proposed addition to the Commission's regulations defines DLRs as reflecting up-to-date forecasts of ambient air temperature, along with other variables, and because *pro forma* OATT Attachment M and the Commission's regulations adopted in this final rule also define an AAR as reflecting up-to-date forecasts of ambient air temperature, implementing DLRs satisfies the requirements in *pro forma* OATT Attachment M to implement AARs.

2. DLR Requirements

a. NOPR Proposal

240. In the NOPR, the Commission preliminarily found that between the two possible approaches to increasing transmission line rating accuracy—requiring AARs or requiring DLRs—an AAR requirement strikes a more appropriate balance between benefits and challenges than a DLR requirement. The Commission explained that, while DLRs can represent more accurate transmission line ratings than AARs, DLRs also present additional costs and challenges that AARs do not present. According to the Commission, these additional costs and challenges, relative to AARs, include placing sensors in remote locations, ensuring an appropriate level of cybersecurity, and various additional costs. Nevertheless, the Commission sought comment on whether to require transmission providers to implement DLRs across their transmission systems or on certain transmission lines that have the most to benefit from DLRs.[491]

241. Recognizing that DLRs have benefits in certain circumstances, the Commission proposed to require RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings (for each period for which transmission line ratings are calculated) at least hourly. Absent these capabilities, the Commission reasoned, the voluntary implementation of DLRs by transmission owners in some RTOs/ISOs would be of limited value, as their more dynamic ratings would not be incorporated into RTO/ISO markets.[492] The Commission stated that it expected that many of the systems and procedures RTOs/ISOs would need to develop are likely to already be required as part of compliance with the proposed AAR requirements. Nonetheless, the Commission sought comment on the additional costs, if any, needed to comply with the proposed requirement that RTOs/ISOs also be able to accommodate frequently updated transmission line ratings from transmission owners.[493]

b. Comments

242. Nearly all transmission owners that filed comments about DLRs either oppose a mandate to implement DLRs on all transmission lines[494] or oppose a mandate in any form.[495] Many of these transmission owners, as well as some RTOs/ISOs, see the merits of DLRs on some transmission lines, but only after taking into account transmission line characteristics that would make DLRs more or less cost effective.[496]

243. In opposing a mandate to implement DLRs on all transmission lines, many transmission owners focus on the cost and challenges associated

[487] 18 CFR 37.6 (Information to be posted on the OASIS).

[488] NOPR, 173 FERC ¶ 61,165 at P 25.

[489] Industrial Customer Organizations Comments at 26.

[490] ACPA/SEIA Comments at 12–13.

[491] NOPR, 173 FERC ¶ 61,165 at P 100.

[492] NOPR, 173 FERC ¶ 61,165 at P 108.

[493] *Id.* P 109.

[494] APS Comments at 8; NYTOs Comments at 2; Indicated PJM Transmission Owners Comments at 13; PG&E Comments at 11–12.

[495] AEP Comments at 6; Dominion Comments at 9; Entergy Comments at 14; BPA Comments at 6; Exelon Comments at 3; PacifiCorp Comments at 5–6; NRECA/LPPC Comments at 3; MISO Transmission Owners Comments at 45–46; ITC Comments at 14–15.

[496] APS Comments at 8; Exelon Comments at 3, 13; PacifiCorp Comments at 5–6; EEI Comments at 15; ITC Comments at 12; AEP Comments at 6; NYTOs Comments at 4, 12–13; Dominion Comments at 9–11; NYISO Comments at 5; PJM Comments at 10–11.

with DLRs. Some offer rough quantitative estimates of these costs. For example, BPA explains that DLR implementation would require significant investment of potentially over $1 million per transmission line in monitoring equipment, software, and hardware to submit and host the data.[497] MISO Transmission Owners explain that one transmission owner's experience with DLRs in MISO suggests that DLR implementation could cost between $100,000 and $200,000 per transmission line. MISO Transmission Owners assert that the cost to implement DLRs on all MISO transmission lines could be $1.5 billion (estimating $150,000 per line multiplied by 10,000 lines on the MISO system).[498]

244. Other transmission owners offer qualitative assessments of the potential costs and challenges associated with DLRs. APS asserts that DLRs are a high cost option with limited benefits.[499] Exelon explains that any investment in DLRs could come at the expense of investment in other equipment.[500] As EEI, Exelon, and NYTOs explain, there are additional costs and challenges associated with sensor and communication technology installation, cybersecurity, and with DLRs themselves, which tend to fluctuate.[501] Entergy does not use DLRs and contends that DLRs present significant technical, logistical, and financial commitments, that the input data is too unpredictable, and that, while sensors work, they are not predictive of future conditions.[502] Dominion also articulates concerns with DLR data interruptions.[503] Others note the challenges associated with implementing DLRs on transmission lines traversing multiple temperature and wind climates.[504] Finally, NYTOs note that, because AARs and DLRs are constantly changing, their use in real-time operations could lead to violations of NERC Reliability Standard FAC–008 if there are discrepancies, potentially caused by a software calculation error. NYTOs are concerned that there would be no allowance for time to identify any calculation errors. For this reason, NYTOs aver that independent software validation solutions would be needed.[505]

245. Many transmission owners believe that DLRs have merit in certain applications, but argue that further study is needed. Some explain that they have experience with DLR pilot projects and limited DLR implementation and state that DLRs are likely economic in certain applications.[506] For example, Dominion explains that it is currently analyzing three separate DLR pilot programs, but cautions that it is too early to judge the effectiveness of the technology.[507] Potomac Economics and several transmission owners caution that the current focus should be on AAR implementation, not DLR implementation, and that the benefits of DLRs should be reassessed after AAR implementation.[508] Sunflower does not rule out support for future DLR implementation, but states that DLRs must be thoroughly studied and tested first.[509] Southern Company and NYTOs oppose implementation of *either* AARs or DLRs on all transmission lines. NYTOs instead suggest a compliance process to select transmission lines for either AAR or DLR implementation similar to the Order No. 1000 process for regional transmission planning, while Southern Company suggests that the Commission adopt a process similar to its ATC requirements and direct transmission providers to identify transmission facilities that would most benefit from both AAR and DLR implementation.[510] While NRECA/LPPC generally do not oppose using AARs and DLRs, they assert that consumer benefits in the form of lower costs should remain the primary focus, so long as safety and reliability are uncompromised. Furthermore, NRECA/LPPC argue that conservative transmission line ratings of facilities must continue to account for unanticipated conditions and human error.[511]

246. Similarly, RTOs/ISOs caution that a full DLR mandate is premature[512] and some argue that the decision to study or pursue DLRs should be left to transmission owners.[513] PJM asserts that RTOs/ISOs could rank the most congested transmission lines, which might serve to test the degree to which such transmission lines might be impacted by DLR implementation, and asserts that DLRs should only be used on the most congested transmission lines.[514] SPP believes that the DLR implementation costs to transmission owners may outweigh the benefits, estimating that DLR implementation that requires an EMS upgrade would cost transmission owners up to $1 million and, without upgrading the EMS, DLR implementation would cost an additional $100,000–$500,000 annually in additional SCADA communications with the Reliability Coordinator's EMS.[515] ISO–NE notes that transmission lines in its territory often do not follow a linear path, which can result in different transmission line ratings for different segments of the same transmission line at the same time if wind speed is taken into account rather than solely ambient air temperature.[516] NYISO explains that its currently-effective DLR functionality and seasonal transmission line ratings "support effective system planning, efficient markets, reliable system operation, and the flexibility needed for NYISO and TO operators to respond to real-time system conditions";[517] however, this has historically been used to increase transmission line ratings in real time based on ambient conditions. NYISO voices concern that frequently updated transmission line ratings, especially those that lower transmission line ratings in real-time during emergency conditions, would have a detrimental effect on reliability in the context of corrective action plans designed to create plans to respond to contingencies, should the system operating limits used to develop the corrective action plan be lowered in real time.[518] NYISO further explains that instances wherein increased transmission line ratings in the day-ahead market resulting in increased commitments are then reduced in the real-time markets could increase uplift costs.[519]

247. The market monitors are divided over the timing and implementation of a DLR mandate. The SPP MMU recommends DLR implementation on all transmission lines, not just congested transmission lines, to account for the interlinkage among transmission lines

[497] BPA Comments at 6.

[498] MISO Transmission Owners Comments at 47.

[499] APS Comments at 8.

[500] Exelon Comments at 16.

[501] EEI Comments at 15; Exelon Comments at 15–16; NYTOs Comments at 4.

[502] Entergy Comments at 14–15.

[503] Dominion Comments at 11.

[504] NYTOs Comments at 12; Exelon Comments at 14; BPA Comments at 6.

[505] NYTOs Comments at 7.

[506] EEI Comments at 15; ITC Comments at 12; AEP Comments at 6; Exelon Comments at 13; APS Comments at 8; NYTOs Comments at 4, 12–13; Dominion Comments at 9–11.

[507] Dominion Comments at 4.

[508] Potomac Economics Comments at 20; ITC Comments at 14–15; PG&E Comments at 11–12; NYTOs Comments at 13.

[509] Sunflower Comments at 5–6.

[510] NYTOs Comments at 10; Southern Company Comments at 2–3.

[511] NRECA/LPPC Comments at 7–8.

[512] CAISO Comments at 16; ISO–NE Comments at 12; NYISO Comments at 7; PJM Comments at 10–11; MISO Comments at 33.

[513] CAISO Comments at 16; PJM Comments at 10–11,13; MISO Comments at 33.

[514] PJM Comments at 12.

[515] SPP Comments at 12.

[516] ISO–NE Comments at 19.

[517] NYISO Comments at 6.

[518] *Id.* at 7–8.

[519] *Id.* at 14.

and to avoid preferential treatment or gaming of transmission lines selected for DLR.[520] On the other hand, Potomac Economics suggests further study and discourages mandates for both universal and targeted DLR implementation at this time.[521] The CAISO DMM states that it would support the use of DLRs where practicable in the future and suggests that conservative assumptions for some applications, such as in the day-ahead market or future advisory intervals, may be appropriate. As such, the CAISO DMM requests that RTOs/ISOs retain the ability to adjust modeled transmission for reliability.[522]

248. State agencies, consumer advocacy groups, and other miscellaneous organizations generally support DLR implementation, but vary widely on what approach the Commission should take. Some groups support the Commission requiring full DLR implementation. R Street Institute contends that DLRs should be required by default, with exception given when justified by a cost-benefit analysis.[523] Industrial Customer Organizations likewise contend that the Commission should require the implementation of DLRs unless a transmission owner can establish that costs would exceed benefits to consumers.[524] ACORE recommends the Commission take further steps to encourage DLR deployment.[525] Clean Energy Parties argue that DLR is superior to AAR, and that the Commission should establish criteria for when DLR is required.[526] ACPA/SEIA contend that DLR can provide significant benefits,[527] and that congestion reviews should evaluate both AARs and DLRs for any congested transmission line.[528]

249. Several groups also argue for more targeted or limited DLR requirements. WATT proposes a list of criteria for requiring DLR implementation,[529] and contends that such criteria can help overcome concern about costs exceeding benefits.[530] ACPA/SEIA similarly support requiring an evaluation of both AARs and DLRs for any congested transmission line, and a DLR requirement where appropriate.[531] EDFR supports requiring DLRs when cost-benefit analysis or public policy justifies their use.[532] EPSA contends that the Commission should first require DLRs only on transmission lines that are deemed to be the most critical for optimizing system performance.[533] Vistra states that it uses DLRs with some of its facilities in ERCOT, and states that it has seen improved congestion management, greater deliverability of low-cost energy to load, lower costs for load, higher revenues for low cost remote generation, and lower hedging costs.[534] Vistra states that DLR benefits will become increasingly important as more zero marginal cost energy resources are added to the resource mix.[535]

250. Several other groups support DLR mandates or oversight of voluntary deployment. TAPS supports voluntary implementation of DLRs, but also argues that subjective deployment decisions should be subject to monitoring.[536] Industrial Customer Organizations contend that the Commission should, at minimum, require the implementation of staggered pilot programs requiring the implementation of DLRs on the most thermally limited, congested transmission lines.[537] Certain TDUs argue that DLR utilization can improve contingency planning and defer or eliminate the need for transmission line upgrades or reconductoring.[538]

251. In response to the Commission's proposal to require RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings (for each period for which transmission line ratings are calculated) at least hourly, however, commenters are broadly supportive. For example, PacifiCorp agrees with the Commission that many of the systems and procedures RTOs/ISOs would need to develop to accept DLRs are likely to already be required as part of compliance with the requirements to adopt AARs.[539] PJM notes that, as part of DLR pilot projects, it has received and reviewed DLRs.[540] Similarly, NYISO notes that it has successfully implemented DLR functionality to allow asset owners to increase real-time transmission line capability, when appropriate, and notes that this implementation does not differentiate between AARs and DLRs.[541]

c. Commission Determination

252. Based on the record, we decline to mandate DLR implementation in this final rule.

253. We agree with commenters that highlight the benefits to DLR implementation.[542] For example, use of DLRs generally allows for greater power flows than would otherwise be allowed, and its use can also detect situations where power flows should be reduced to maintain safe and reliable operation and avoid unnecessary wear on transmission equipment.[543] We agree with EPSA, which, citing to a PJM pilot program with AEP and PPL Electric Utilities Corporation, explains that there could be significant benefits to strategically expanding DLR deployment.[544] Additionally, we agree with Exelon that there may be targeted applications in which DLRs can provide net benefits to customers. For example, when the limiting element for a transmission facility experiencing significant congestion is the conductor and conditions besides ambient air temperature have a consistent and significant impact on the power carrying capabilities of the line, DLRs may provide more accurate transmission line ratings than AARs and therefore may provide significant benefits.[545]

254. However, we appreciate that while DLRs can represent more accurate transmission line ratings than AARs, DLR implementation also presents additional costs and challenges not found in AAR implementation. Relative to AARs, these additional costs and challenges include placing sensors in remote locations, ensuring the cybersecurity of sensors, and various additional costs. The record in this proceeding is not sufficient for the Commission to evaluate the relative benefits and costs and challenges of DLR implementation. For this reason,

[520] SPP MMU Comments at 4.

[521] Potomac Economics Comments at 20.

[522] CAISO DMM Comments at 2–3.

[523] R Street Institute Comments at 3.

[524] Industrial Customer Organizations Comments at 5.

[525] ACORE Comments at 1.

[526] Clean Energy Parties Comments at 5, 7.

[527] ACPA/SEIA Comments at 5–6.

[528] *Id.* at 9–11.

[529] WATT proposes for sensor-based DLR to be required on all thermally limited transmission lines rated 69 kV or greater when market congestion totaling over $1 million has occurred within the past year; the transmission line is identified as being a constraint projected to have market congestion over $1 million over the coming three years as a part of the current RTO/ISO transmission planning cycle process, which can be economic or reliability based; thermally limited transmission lines show up as limiting in generator interconnection system impact studies; or generation curtailed by more than 10% on average for one year due to factors that include transmission line capacity. WATT Comments at 10.

[530] *Id.* at 2, 10–11.

[531] ACPA/SEIA Comments at 8–10.

[532] EDFR Comments at 4.

[533] EPSA Comments at 6.

[534] Vistra Comments at 2–3.

[535] *Id.* at 3.

[536] TAPS Comments at 15–17.

[537] Industrial Customer Organizations Comments at 25.

[538] Certain TDUs Comments at 6–7.

[539] PacifiCorp Comments at 6.

[540] PJM Comments at 11–12.

[541] NYISO Comments at 4.

[542] Clean Energy Parties Comments at 6; EPSA Comments at 5; Exelon Comments at 13.

[543] Clean Energy Parties Comments at 6.

[544] EPSA Comments at 5.

[545] Exelon Comments at 13.

we incorporate the record in this proceeding on DLRs into new Docket No. AD22–5–000, which we open to further explore DLR implementation.

255. Finally, we adopt the Commission's proposal in the NOPR to require RTOs/ISOs to establish and maintain systems and procedures necessary to allow transmission owners to electronically update transmission line ratings (for each period for which transmission line ratings are calculated) at least hourly, with such data submitted by transmission owners directly into the RTO's/ISO's EMS through SCADA or related systems.[546] We continue to find that, because DLR implementation may be economic in certain applications,[547] absent RTOs/ISOs having these capabilities, 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. Absent these minimum capabilities, RTO/ISO software would serve as a barrier that prevents transmission owners in RTOs/ISOs from implementing DLRs that can better reflect the actual transfer capability of the transmission system and, consequently, wholesale rates would not remain just and reasonable. Additionally, as the Commission stated in the NOPR, we continue to expect that many of the systems and procedures RTOs/ISOs would need to develop to accept DLRs are likely to already be required as part of compliance with the AAR requirements adopted in this final rule.

3. Extending to Non-RTO/ISO Transmission Providers the Requirement To Allow Transmission Owners To Electronically Update Transmission Line Ratings at Least Hourly

a. NOPR Proposal

256. In addition to requiring RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly, the Commission also sought comment on whether there is any need to extend this same requirement to transmission providers that operate outside of an RTO/ISO.[548]

b. Comments

257. Comments on this question are limited. EEI and PacifiCorp state that there is no need to extend this requirement beyond RTOs/ISOs.[549] R Street Institute, however, observes that transmission management inefficiency and transmission line rating opacity outside RTOs/ISOs is far greater than within RTOs/ISOs, and therefore concludes that updating transmission line ratings hourly outside RTOs/ISOs would be a prudent start.[550] Similarly, WATT argues that the same requirements should apply consistently across RTOs/ISOs and non-RTOs/ISOs, noting concerns of utilities considering voluntary RTO/ISO membership that regulatory requirements are stricter within RTOs/ISOs than outside RTOs/ISOs which serves as a disincentive to RTO/ISO participation.[551]

c. Commission Determination

258. We decline to extend the requirement for RTOs/ISOs to be able to accept DLRs to non-RTO/ISO transmission providers at this time. As EEI explains, in most cases outside of an RTO/ISO market, transmission providers operate only their own transmission systems. In those cases, transmission providers have the ability to fully implement DLRs should they choose to do so. Because non-RTO/ISO transmission providers are also typically the transmission owner, we find that any requirement for non-RTO/ISO transmission providers to be able to accept DLRs would be unnecessary.

4. DLR Studies

a. NOPR Proposal

259. In the NOPR, the Commission sought comment on whether to require RTOs/ISOs to conduct a one-time study of the cost effectiveness of DLR implementation, and if so, what details/format any such study should include.[552]

b. Comments

260. Most transmission owners oppose requirements for RTOs/ISOs to study the cost effectiveness of DLR implementation.[553] One exception is PG&E, which argues that an RTO/ISO study could identify the efficacy of system-wide DLR implementation relative to more localized use.[554] Exelon opposes a study requirement, asserting that it would be costly, time-consuming, and duplicative to existing processes.[555] Indicated PJM Transmission Owners contend that there would be little point in PJM conducting another DLR study and caution that any DLR study would be costly and highly locational in nature, possibly necessitating DLR sensor installation.[556] MISO Transmission Owners question whether the RTO/ISO is the appropriate entity to study the cost effectiveness of DLR implementation and further explain that certain study details remain unaddressed.[557] Therefore, MISO Transmission Owners assert that the Commission should provide flexibility for transmission owners and RTOs/ISOs to collaborate on a voluntary basis to conduct DLR studies.[558] EEI also does not support a mandate to study DLR cost effectiveness, explaining that RTOs/ISOs already study congestion and solutions to resolve congestion in the transmission planning processes.[559] Dominion cautions that, should the Commission require DLR studies, such studies should involve transmission owners.[560] Finally, Certain TDUs explain that transparency into the benefits of DLRs is important, and they therefore support DLR studies, but argue that studies should involve the RTOs/ISOs and be incorporated into the transmission planning processes.[561]

261. Several RTOs/ISOs also discourage the Commission from requiring DLR studies.[562] MISO states that studies should be transmission line specific and driven by the transmission owners.[563] ISO–NE does not believe a study is necessary until, and unless, AARs are fully implemented. ISO–NE recommends that, if a study is required, it be carried out by a third party.[564] CAISO opposes DLR cost-effectiveness study requirements but would not

[546] However, we add the DLR requirement adopted herein to 18 CFR 35.28(g)(13), rather than to 18 CFR 35.28(g)(12) as proposed in the NOPR, in light of the requirements recently approved in Order No. 2222. *See Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 2222, 85 FR 68450 172 FERC ¶ 61,247 (2020), *order on reh'g,* Order No. 2222–A, 174 FERC ¶ 61,197 (2021).

[547] EEI Comments at 15; ITC Comments at 12; AEP Comments at 6; Exelon Comments at 13; APS Comments at 8; NYTOs Comments at 4, 12–13; Dominion Comments at 9–11.

[548] NOPR, 173 FERC ¶ 61,165 at P 109.

[549] EEI Comments at 18–19; PacifiCorp Comments at 6.

[550] R Street Institute Comments at 5.

[551] WATT Comments at 15.

[552] NOPR, 173 FERC ¶ 61,165 at P 110.

[553] MISO Transmission Owners Comments at 38; ITC Comments at 15; Exelon Comments at 6; Dominion Comments at 12; EEI Comments at 16; Indicated PJM Transmission Owners Comments at 13–14.

[554] PG&E Comments at 11.

[555] Exelon Comments at 6.

[556] Indicated PJM Transmission Owners Comments at 13–14.

[557] Specifically, MISO Transmission Owners explain that the Commission should clarify for what purpose the study results would be used.

[558] MISO Transmission Owners Comments at 38.

[559] EEI Comments at 16.

[560] Dominion Comments at 12.

[561] Certain TDUs Comments at 7.

[562] CAISO Comments at 16; ISO–NE Comments at 12; MISO Comments at 33.

[563] MISO Comments at 33.

[564] ISO–NE Comments at 12.

oppose an informational report on its work with stakeholders evaluating the costs and benefits of DLRs.[565] PJM argues that several outstanding issues should be studied and recommends: (1) Periodic reporting requirements by region on the status and lessons learned from DLR deployments; (2) requiring transmission owners to document their DLR implementation processes; and (3) technical conferences to share best practices on DLR implementation.[566] SPP notes that it recently published a whitepaper that examined the costs and benefits of DLRs.[567]

262. EPRI argues that, before studies on DLR cost effectiveness can be conducted, studies on monitoring systems must be conducted. According to EPRI, such studies must identify a technical basis to select sensors, establish the accuracy of sensors, develop an understanding of sensors' reliability and maintenance needs, and identify methods to integrate monitoring system data into an EMS. EPRI states that unbiased information on monitoring systems is not yet available and explains that some commercial DLR monitoring equipment may not be up to utility standards.[568]

263. While RTOs/ISOs and transmission owners generally oppose a study requirement, several commenters are more supportive of DLR study requirements. New England State Agencies support independent studies on the cost-effectiveness of DLRs as a first step before ordering implementation.[569] Ohio FEA does not support Commission requirements for RTOs/ISOs to study the cost effectiveness of DLR implementation, but, noting that DLRs may be cost effective on certain lines, states that pilot programs should be initiated to identify these segments through the stakeholder process rather than a requirement.[570] CEA supports DLR feasibility studies to address the cost of infrastructure and EMS–SCADA changes, the challenges of implementing DLRs on transmission lines with varying climates and little communications infrastructure, and DLR forecasting challenges, but questions whether risks and costs will be borne by RTOs/ISOs or by transmission owners.[571] Clean Energy Parties support requiring RTOs/ISOs to conduct a study of the cost effectiveness of DLR implementation.[572] OMS contends that industry and regulators need more information to better understand the potential benefits of DLRs.[573]

c. Commission Determination

264. In consideration of the comments on this issue, we decline to require one-time DLR studies at this time. We agree with New England State Agencies and OMS that studies assessing the cost effectiveness of DLR implementation may be useful to transmission providers in identifying possible transmission line candidates for DLR deployment and serve as a good first step prior to consideration of additional requirements.[574] Specifically, such studies may support the development of various criteria transmission providers could use to identify candidates for DLR deployment.[575] However, we also agree that there are various factors to consider in order to determine when and how such studies should be conducted, including whether such studies: Should be conducted by independent third parties; should incorporate the adoption of AARs into the analysis;[576] and would overlap with existing congestion studies in RTOs/ISOs.[577] Although we decline to require one-time DLR studies at this time, we incorporate the record in this proceeding on DLRs into new Docket No. AD22–5–000, which we open to further explore DLR implementation.

5. Advanced Transmission Technology Cost Recovery

a. Comments

265. ENEL states that advanced transmission technologies can achieve cost savings and provide value to ratepayers, such that transmission owners should be eligible to recover their costs through rate base and to earn a return, and requests clarification on the cost allocation and recovery associated with AAR and DLR implementation.[578]

b. Commission Determination

266. We are not considering in this proceeding whether to grant special rate treatment for technologies used to implement AARs and DLRs. We are also not considering in this proceeding whether to change the Commission's policies regarding cost recovery. While the purchase and installation cost of equipment that may normally be considered as plant in service may be eligible for inclusion in rate base, without knowing the specific facts related to a particular investment, it would be impractical to address their cost recovery at this time. However, once specific costs are known, parties can file with the Commission to seek recovery, as appropriate.[579]

F. Emergency Ratings

1. NOPR Request for Comments

267. In the NOPR, the Commission sought comment on: (1) Whether to require transmission providers to use unique emergency ratings; (2) the degree to which transmission providers use or are provided with unique emergency ratings and the emergency rating durations that are commonly used; (3) whether and how requirements to implement unique emergency ratings would impact the useful life of transmission equipment; and (4) the feasibility of calculating emergency ratings on transmission equipment other than conductors and transformers.[580] The Commission stated that emergency ratings should not be arbitrarily set equal to normal ratings, but rather should be developed from appropriate, unique technical inputs.[581] The Commission acknowledged that there may be some instances when, after a proper technical analysis considering the relevant rating timeframes, the emergency rating is equal to the normal rating.[582]

268. The Commission observed that, for short periods of time, most transmission equipment can withstand high currents without sustaining damage, which allows transmission owners to develop two sets of ratings for most facilities: Normal ratings that can be safely used continuously (*i.e.,* not time-limited) and emergency ratings that can be safely used for a limited period of time. Whether and how a transmission owner establishes emergency ratings is important because emergency ratings are a critical input into determining operating limits in market models, both during normal operations and during post-contingency operations. Market models often allow

[565] CAISO Comments at 16.

[566] PJM Comments at 13–14.

[567] SPP Comments at 15.

[568] EPRI Comments at 5.

[569] New England State Agencies Comments at 14.

[570] Ohio FEA Comments at 6–7.

[571] CEA Comments at 2–3.

[572] Clean Energy Parties Comments at 11.

[573] OMS Comments at 12.

[574] New England State Agencies Comments at 14; OMS Comments at 12.

[575] WATT Comments at 10; ACPA/SEIA Comments at 9–10; Clean Energy Parties Comments at 7–10.

[576] ISO–NE Comments at 11–12.

[577] EEI Comments at 16; Exelon Comments at 6.

[578] ENEL Comments at 2–3.

[579] Note that the Commission convened a workshop on September 10, 2021, to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. Notice of Workshop, Docket Nos. AD19–19–000, RM20–10–000 (Apr. 15, 2021).

[580] NOPR, 173 FERC ¶ 61,165 at PP 111–113.

[581] *Id.* P 110.

[582] *Id.* P 46 n.57.

post-contingency flows on transmission lines to exceed normal ratings for short periods of time, as long as the flows do not exceed the applicable emergency rating for the corresponding timeframe. Because these emergency ratings are a more accurate representation of the flow limits over shorter timeframes, their use in models of post-contingency flows may produce prices which more accurately reflect actual costs to delivering wholesale energy to transmission customers. Since the transmission system is operated to withstand contingencies, the use of unique emergency ratings, where appropriate, allows for greater flows during normal conditions as well. The Commission further stated that this greater transfer capability can provide significant cost savings and afford transmission providers additional flexibility in how to respond to unforeseen events.[583] Noting the potential negative consequences of emergency ratings, however, the Commission recognized concerns that the use of emergency ratings could impact reliability by degrading affected transmission facilities and ultimately reducing the equipment's useful life.[584]

2. Emergency Ratings Definition and Implementation Requirements

a. Comments

269. Some transmission owners oppose a potential mandate to require unique emergency ratings,[585] while others do not oppose the use of emergency ratings, but oppose a mandate, asking for flexibility to determine how and when to use emergency ratings.[586] Some transmission owners note that they use emergency ratings on their systems,[587] while several of these support the use of emergency ratings.[588] PG&E, for example, notes that it currently uses emergency ratings for both planning and real-time operations.[589] APS states that the use of emergency ratings gives operators sufficient time to respond and supports their use during post-contingency operations for a 30-minute timeframe.[590] Tangibl notes that PJM's experience shows that implementation and use of unique emergency ratings is longstanding and feasible.[591]

270. Four RTOs/ISOs indicate that they use emergency ratings.[592] RTOs/ISOs are evenly divided on potential requirements to calculate and implement emergency ratings. CAISO and MISO oppose an emergency rating mandate. CAISO believes that there is no need for a mandate since it already maintains emergency ratings in the CAISO register of transmission and facility line ratings; MISO argues that any such mandate, if directed, should be to transmission owners.[593] Of the RTOs/ISOs in support of potential emergency ratings requirements, ISO–NE recognizes the benefits resulting from their use and NYISO is supportive so long as the equipment supports the transmission line rating.[594]

271. Market monitors, independent agencies, technical experts, renewable energy advocates, generation companies, and load all generally support the use of unique emergency ratings[595] and most support requirements for their use.[596] The SPP MMU and Potomac Economics support requiring transmission providers to establish emergency ratings using unique technical inputs that are separate from normal ratings.[597] Potomac Economics notes that transmission owners will not voluntarily adopt broad or consistent emergency ratings use without a requirement.[598] Industrial Customer Organizations state that the need for accurate transmission line ratings applies especially during emergency operations.[599] Tangibl contends that a spot check of facilities in PJM shows that almost all have unique emergency ratings.[600]

272. Many transmission owners emphasize that emergency ratings can be the same as the normal rating[601] and state the importance of transmission owner discretion in setting emergency ratings.[602] MISO and CAISO oppose any unique emergency ratings mandate, claiming that good reasons may exist to justify their not being unique.[603] CAISO, NYISO, and MISO provide examples of cases where emergency ratings could be the same as the normal rating for a transmission facility.[604] Recognizing these cases, CAISO requests that any final rule requiring unique emergency ratings allow for and appropriately account for exceptions.[605] The SPP MMU and Potomac Economics support requiring transmission providers to establish emergency ratings using unique technical inputs that are separate from normal ratings.[606]

273. ITC and MISO Transmission Owners argue that requiring unique emergency ratings could create a perverse incentive for normal ratings to be revised downward so that there can be unique emergency ratings.[607] Similarly, MISO argues that it is sub-optimal to artificially lower the normal ratings to create the appearance of a deviation from the emergency rating when they would otherwise be equal.[608] MISO Transmission Owners assert that requiring emergency ratings that are unique from normal ratings is unnecessary and arbitrary.[609]

274. MISO states that the NOPR appears to regard cases where transmission lines have equal emergency and normal ratings as exceptional although they may occur regularly.[610] MISO Transmission

[583] *Id.* P 112.

[584] *Id.* P 113.

[585] Dominion Comments at 12; EEI Comments at 16–17; MISO Transmission Owners Comments at 17; NRECA/LPPC Comments at 25–26; Southern Company Comments at 4.

[586] *See, e.g.,* EEI Comments at 16–17; SDG&E Comments at 4–5. Exelon and ITC, while not opposing or supporting a mandate for the use of emergency ratings, similarly contend that transmission owners should be responsible for calculating emergency ratings and determining the facilities for which they are appropriate. Exelon Comments at 19–20; ITC Comments at 12.

[587] APS Comments at 7; Dominion Comments at 4; Entergy Comments at 1; EEI Comments at 16; Exelon Comments at 22; Indicated PJM Transmission Owners Comments at 2; PacifiCorp Comments at 4; PG&E Comments at 12; SDG&E Comments at 3; WAPA Comments at 8.

[588] APS Comments at 7; Dominion Comments at 4; Exelon Comments at 22; Indicated PJM Transmission Owners Comments at 15; PacifiCorp Comments at 4.

[589] PG&E Comments at 12.

[590] APS Comments at 7.

[591] Tangibl Comments at 4.

[592] CAISO Comments at 1; NYISO Comments at 3; ISO–NE Comments at 6; MISO Comments at 25.

[593] CAISO Comments at 15; MISO Comments at 24–25 & n.45.

[594] NYISO Comments at 14 n.13; ISO–NE Comments at 10.

[595] ACPA/SEIA Comments at 17; EDFR Comments at 6; Industrial Customer Organizations Comments at 27; R Street Institute Comments at 3; Tangibl Comments at 2; WATT Comments at 13 (supported in general by LineVision).

[596] EDFR Comments at 6; Potomac Economics Comments at 4; R Street Institute Comments at 3; SPP MMU Comments at 5; Tangibl Comments at 2; WATT Comments at 13 (supported in general by LineVision).

[597] Potomac Economics Comments at 4; SPP MMU Comments at 5.

[598] Potomac Economics Comments at 4.

[599] Industrial Customer Organizations Comments at 27.

[600] Tangibl Comments at 3.

[601] *See, e.g.,* Entergy Comments at 4; Exelon Comments at 19–20; ITC Comments at 3; MISO Transmission Owners Comments at 17; NRECA/LPPC Comments at 25; SDG&E Comments at 4.

[602] *See, e.g.,* EEI Comments at 16–17; Exelon Comments at 19–20; ITC Comments at 12; MISO Transmission Owners Comments at 40–41; Indicated PJM Transmission Owners Comments at 15; SDG&E Comments at 4–5.

[603] CAISO Comments at 15; MISO Comments at 24–25.

[604] CAISO Comments at 15; NYISO Comments at 14 n.13; MISO Comments at 24–25.

[605] CAISO Comments at 15.

[606] SPP MMU Comments at 5; Potomac Economics Comments at 4.

[607] ITC Comments at 12; MISO Transmission Owners Comments at 17; MISO Comments at 25.

[608] MISO Comments at 25.

[609] MISO Transmission Owners Comments at 40.

[610] MISO Comments at 25.

Owners read the NOPR as suggesting that having the same rating for normal and emergency operations reflects a lack of effort by transmission owners to analyze and incorporate appropriate emergency ratings.[611] According to MISO Transmission Owners, it would not be problematic for the Commission to require separate normal and emergency ratings on facilities where transmission owners determine they are appropriate.[612] Similarly, MISO argues that transmission owners should evaluate a facility's normal and emergency capability separately and distinctly where each transmission line rating fully uses the technical capabilities of the installed equipment considering good utility practice, sound engineering judgment, manufacturer guidance, and equipment reliability experience for each rating type.[613]

275. The SPP MMU states that there may be cases when normal and emergency ratings are legitimately equal, but that should only be true for a very small number of transmission lines.[614] The SPP MMU notes that nearly 60% of transmission lines in SPP have identical normal and emergency ratings and argues that emergency ratings should only rarely be equal to normal ratings. Potomac Economics states that only roughly one third of the transmission line ratings provided for contingency constraints in MISO are emergency ratings compared to MISO's report that 90% of its binding constraints are contingent constraints that should be based on emergency ratings.[615]

276. OMS contends that emergency ratings should serve as the foundation for AARs.[616] OMS agrees with MISO Transmission Owners that normal and emergency ratings should not always be unique, but argues that transmission line ratings that are the same value can be derived using different methodologies.[617] OMS contends that transmission owners have the responsibility to judge the reasonableness of using non-unique emergency ratings subject to transmission provider and market monitor review.[618] EPRI states that high operating temperatures, other limiting elements in the circuit, and inability to withstand additional annealing (loss of tensile strength of the conductor through heating) may all contribute to finding emergency ratings that are identical to normal ratings, although such ratings would nonetheless be considered unique if they were developed using appropriate technical inputs.[619] Many commenters express support for requirements to provide justifications when normal and emergency ratings are identical, given that it may be appropriate in some situations for normal and emergency ratings to be identical.[620] TAPS states that the result of any individual transmission owner decision not to provide accurate emergency ratings may tie the hands of RTOs/ISOs dealing with contingencies.[621]

277. Transmission owners indicate that they use different durations for calculating emergency ratings, including hourly, daily, and two-day ahead short-term emergency ratings by Entergy,[622] up to 30 minutes during post-contingency operations by APS,[623] 30 minutes by PacifiCorp,[624] and four hours by PG&E.[625] Exelon states that it calculates four-hour emergency ratings, with long-term emergency and short-term emergency ratings set equal unless a shorter duration transmission line rating is feasible on the facility, as well as load dump ratings for up to 15 minutes.[626] Exelon notes that flexibility in the duration of emergency ratings can be beneficial and some equipment, such as phase angle regulators, can allow the transmission owner to control the flow and avoid damage from shorter-term ratings.[627] R Street Institute notes that some transmission operators use a 30 minute duration and others use two to four hour durations.[628] OMS argues that emergency ratings must accurately reflect the capability of the transmission element for a standardized, limited period of time.[629] OMS also contends that the Commission should require transmission providers to define what constitutes an emergency rating in their region and how they should be used.[630]

278. RTOs/ISOs similarly indicate that they use different durations for calculating emergency ratings, including long time emergency (four hours for winter, 12 hours for summer), short time emergency (15 minutes), and drastic action limits (five minutes) in ISO–NE,[631] up to four hours in CAISO (with some transmission owners providing shorter duration transmission line ratings),[632] and 30 minutes in MISO.[633] The SPP MMU recommends that emergency ratings be applicable on a shorter-term basis, meaning less than four hours in SPP, to observe limits of the equipment and prevent degradation.[634] The SPP MMU does not recommend requiring transmission owners to exceed normal ratings to address challenges during sustained periods of contingencies or long duration events, such as polar vortex conditions.[635] Potomac Economics recommends that any emergency ratings requirements specify the maximum permissible duration to enhance RTOs/ISOs' situational awareness and reliability.[636]

279. Many transmission owners express concern that the use of emergency ratings could risk degrading the asset and reducing its useful life.[637] SDG&E states that it does not issue unique emergency ratings for certain types of equipment due to the potential for permanent damage.[638] A few transmission owners note that the age and condition of the facilities impact whether an emergency rating may risk further damage to transmission equipment.[639] Indicated PJM Transmission Owners state that for some facilities, even minimal use of emergency ratings can have a significant impact on the facility's useful life.[640] Indicated PJM Transmission Owners note that the overuse of emergency ratings could cause asset degradation and in turn increase costs to consumers as those facilities have to be upgraded or replaced, while also having a negative impact on system reliability.[641] Both NRECA/LPPC and Entergy note that if conductors violate sag requirements from the use of emergency ratings then they pose a risk to public

[611] MISO Transmission Owners Comments at 17.

[612] *Id.* at 40.

[613] MISO Comments at 25–26.

[614] SPP MMU Comments at 4–5.

[615] Potomac Economics Comments at 7, 11.

[616] OMS Reply Comments at 11–12.

[617] *Id.* at 12.

[618] OMS Comments at 15.

[619] EPRI Comments at 7, 9–10.

[620] R Street Institute Comments at 3, 5; ACPA/SEIA Comments at 16–17; EDFR Comments at 6; TAPS Comments at 2.

[621] TAPS Comments at 18.

[622] Entergy Comments at 4.

[623] APS Comments at 7.

[624] PacifiCorp Comments at 4.

[625] PG&E Comments at 12.

[626] Exelon Comments at 21.

[627] *Id.* at 20.

[628] R Street Institute Comments at 7.

[629] OMS Comments at 13–14.

[630] *Id.* at 15.

[631] ISO–NE Comments at 6.

[632] CAISO Comments at 1, 3.

[633] MISO Comments at 23.

[634] SPP MMU Comments at 13–14.

[635] *Id.* at 5.

[636] Potomac Economics Comments at 13.

[637] *See, e.g.,* APS Comments at 7; Dominion Comments at 4; EEI Comments at 17; Entergy Comments at 2; Exelon Comments at 22–23; Indicated PJM Transmission Owners Comments at 16–17; ITC Comments at 12.

[638] SDG&E Comments at 4.

[639] EEI Comments at 17; Exelon Comments at 20.

[640] Indicated PJM Transmission Owners Comments at 17.

[641] *Id.* at 2–3; Entergy Comments at 15.

safety and reliability.[642] Entergy lists several risks from the use of emergency ratings, including creep, elongation, and loss of conductor strength as well as the fact that several factors that determine emergency ratings cannot be known in advance, such as pre-load current, pre-load temperature, contingency current, and theoretical contingency steady state temperature.[643] According to EPRI, there are conditions when emergency ratings cannot be safely used, including when other parts of the circuit are already overloaded or when the conductor would be compromised or is too old.[644] Entergy states that emergency ratings are risker than, and have a significantly greater potential to damage transmission equipment than, the use of AARs; therefore, Entergy contends, emergency ratings should be used for a short-term basis, on a limited number of facilities, and carefully monitored.[645] Exelon states that emergency ratings are acceptable for a short duration, but warns that regular excessive loading will impact a facility's useful life.[646]

280. NRECA/LPPC argues that emergency ratings may not be applicable, beneficial, or sustainable for all transmission lines.[647] Indicated PJM Transmission Owners note that there is a balance between the benefits of emergency ratings and the negative impacts of overuse or misuse of emergency ratings.[648] Indicated PJM Transmission Owners claim that the use of emergency ratings may reduce costs to consumers in some short-term cases but there is no evidence to support savings in the long term and instead their use will likely increase transmission costs.[649] PacifiCorp asserts that implementing requirements for emergency ratings on equipment other than transmission lines would require voluminous amounts of data and additional databases and personnel.[650] EEI states that universal use of seasonal and emergency ratings may provide only a negligible improvement beyond current transmission line ratings.[651] BPA asserts that it currently operates to its maximum operating temperature limits, and therefore would see no increase in capacity from the use of emergency ratings.[652] Dominion states that it does not use emergency ratings for ATC calculations on the Dominion Energy South Carolina system because emergency ratings are for short durations and specific circumstances.[653]

281. On the other hand, PacifiCorp states that it has seen no detriment to reliability from using emergency ratings for their transmission lines for over a decade.[654] WAPA states that using emergency ratings for short durations does not pose too much risk to the integrity and condition of the device.[655]

282. Several commenters note methods to manage the impact of emergency ratings on equipment. MISO recommends that the Commission allow transmission owners to establish reasonable and supported reliability margins where higher emergency ratings are established such as: (1) A safety margin to ensure the transmission line rating is less than the relay trip rating and maximum power transfer rating; and (2) allowing defined, reasonable limits on the duration and frequency of emergency ratings.[656] Potomac Economics argues that emergency ratings are designed to permit temporary use without equipment damage, such as significant annealing, and states that if post-contingent responses are in question, RTOs/ISOs can and do develop special operating guides to specify the operating conditions required to use emergency ratings and maintain reliability.[657] Potomac Economics contends that transmission owners should continue to have the authority and responsibility to determine reliable emergency ratings, but states that vague or general concerns should not forestall requirements to provide emergency ratings for most facilities.[658] Tangibl also notes that sag limitations can be addressed in some cases.[659]

283. Several commenters identify benefits of emergency ratings use, including increased transfer capability and relieving congestion, which can be a valuable reliability tool[660] and also lead to lower prices for customers.[661] Several other commenters point to more efficient use of the transmission system as a result of emergency ratings.[662] Potomac Economics' analysis, for example, found the potential for $48.1 million in 2019 and $49.5 million in 2020 in savings in MISO alone that could have been realized by using emergency ratings for facilities for which only normal ratings were provided.[663]

284. Indicated PJM Transmission Owners express concern with Potomac Economics' emergency rating cost and benefit analysis, though, noting the absence of increased operations, maintenance, and capital costs associated with running the system at emergency conditions.[664] MISO Transmission Owners similarly express concern with Potomac Economics' analysis and state that the Commission should not rely on that analysis, including estimates that the lack of unique emergency ratings by some transmission owners in MISO contributed to $62–68 million in extra congestion costs.[665]

285. In its reply comments, Potomac Economics contends that their estimations are conservative and emphasize the importance of using emergency ratings, since the cost savings are comparable to the benefits of AARs.[666] Potomac Economics also notes that requirements to implement emergency ratings would still be placed on transmission owners, and they retain discretion in setting emergency ratings based on reliability, subject to transparency and their reasonableness.[667] The SPP MMU states that accurate emergency ratings would make transmission congestion more uniformly defined throughout the footprint, thus helping reduce congestion and creating more uniform prices.[668] Potomac Economics argues that emergency ratings provide additional benefits beyond more efficient use of the transmission system and enhanced reliability, including increased operational awareness for RTOs/ISOs and other transmission providers regarding the capability of the transmission facilities.[669] New England State Agencies argue that accurate emergency ratings could prevent unnecessary curtailment of generation, and in extreme circumstances, avoid

[642] NRECA/LPPC Comments at 25; Entergy Comments at 13.

[643] Entergy Comments at 13–14.

[644] EPRI Comments at 7.

[645] Entergy Comments at 11.

[646] Exelon Comments at 22–23.

[647] NRECA/LPPC Comments at 25.

[648] Indicated PJM Transmission Owners Comments at 3.

[649] *Id.* at 15–17.

[650] PacifiCorp Comments at 5.

[651] EEI Comments at 4.

[652] BPA Comments at 7.

[653] Dominion Comments at 13.

[654] PacifiCorp Comments at 4.

[655] WAPA Comments at 8.

[656] MISO Comments at 26.

[657] Potomac Economics Comments at 14.

[658] *Id.* at 14.

[659] Tangibl Comments at 5.

[660] EDFR Comments at 6.

[661] ISO–NE Comments at 10; New England State Agencies Comments at 21; PacifiCorp Comments at 4; Potomac Economics Comments at 8, 10; WAPA Comments at 8.

[662] Tangibl Comments at 5; EDFR Comments at 6; ACP Comments at 16–17.

[663] Potomac Economics Comments at 8.

[664] Indicated PJM Transmission Owners Comments at 16.

[665] MISO Transmission Owners Comments at 43–44.

[666] Potomac Economics Reply Comments at 6–7.

[667] *Id.* at 11.

[668] SPP MMU Comments at 13.

[669] Potomac Economics Comments at 8, 10.

shedding load.[670] R Street Institute similarly contends that the benefits of emergency ratings go beyond the production cost savings estimated by Potomac Economics and include avoided customer outages.[671] R Street Institute notes that the cost of additional wear must consider the frequency and duration of emergency rating use, which is usually uncommon and brief.[672] EPRI contends that emergency ratings will provide less benefits when AARs or DLRs are already used because the starting temperature of the conductor may be higher than under static ratings.[673]

286. ACPA/SEIA state that emergency ratings are important to ensure safe operating conditions and because they often determine the loading allowed on constrained facilities even during normal conditions.[674] Tangibl also contends that unique emergency ratings may reveal potential low-cost system upgrades, allow more efficient transmission planning, reduce the time and cost of interconnection studies, and reduce barriers to the development of new generation.[675] Additionally, Tangibl notes that when unique emergency ratings are not used, it potentially causes needless curtailments for renewable energy projects.[676] R Street Institute contends that emergency ratings should be required regardless of RTO/ISO participation, to avoid a disincentive to RTO/ISO membership, and that inaccurate emergency ratings are unjust and unreasonable.[677] R Street Institute recognizes that the record on emergency ratings is sparse and that implementing emergency ratings may be prone to operator error, but notes that they are sometimes used implicitly during emergency conditions.[678]

287. Almost all transmission owners that discussed emergency ratings in their comments agree that emergency ratings should be used judiciously for reliability reasons, and not regularly for economics, to access additional transfer capability.[679] Entergy states that emergency ratings can be used only in real-time operations and should not be used in markets.[680] Indicated PJM Transmission Owners agree with the NOPR statement that emergency ratings allow for higher operating limits, and thus, more efficient system commitment and dispatch solutions, but argues that emergency ratings should be used only during emergencies and not to increase capacity during normal operating conditions due to the risks of wear and additional costs.[681] Dominion and EEI advocate for using emergency ratings only on an as-needed basis.[682] Exelon contends that the benefits of using emergency ratings under emergency conditions outweigh the costs.[683]

288. Potomac Economics argues that the Commission should clarify that the unique emergency ratings be applied for contingent constraints, stating that approximately half of the potential benefits and reduced production costs of the rulemaking could be lost without such a clarification.[684] New England State Agencies and OMS agree that accurate emergency ratings could provide important benefits.[685] However, New England State Agencies argue that more information is needed.[686]

289. Regarding implementation, PacifiCorp states that the ability to use emergency ratings in TTC on path ratings[687] is more complex than being able to calculate them because this requires contingency analysis.[688] Entergy states that emergency ratings implementation is complicated by the thermal time constraint being different for all conductors based on size and construction.[689]

290. ITC asserts that AARs should be used for both normal ratings (pre-contingency operations) and emergency ratings (post-contingency operations) because congestion is often caused by projected post-contingency flows.[690] EDFR and Industrial Customer Organizations state that, where appropriate, emergency ratings could be combined with DLRs for additional benefits.[691] Similarly, PG&E supports considering the benefits of AARs for both normal and emergency ratings.[692] By contrast, ACPA/SEIA encourage the consideration of seasonal line rating information in developing emergency ratings, similar to the framework for using seasonal line ratings for long-term transmission service.[693]

291. ISO–NE states that an update to the overall transmission line rating methodology to include AARs may also necessitate the need for new emergency ratings based on those AARs.[694] Potomac Economics supports a requirement that transmission owners calculate and use AARs based on emergency ratings for contingency constraints.[695] NYTOs state that having normal and emergency ratings could preempt the need to establish an AAR mandate on all transmission lines.[696]

b. Commission Determination

292. Based on the record developed in this proceeding, we are persuaded that it is appropriate to adopt certain requirements for emergency ratings. Whether and how a transmission owner establishes emergency ratings is important because emergency ratings are a critical input into determining transfer capability, both during normal operations and during post-contingency operations. There is a significant record of transmission owners and transmission providers already using emergency ratings.[697] For example, Exelon notes that it already calculates emergency ratings for its transmission facilities and that the benefits of using emergency ratings during emergencies outweigh the costs of establishing them.[698] There is also an extensive record on the role of emergency ratings in ensuring reliable and efficient operations. Specifically, transmission owners and transmission providers report benefits from implementing emergency ratings including increased transmission capacity,[699] additional time to respond to contingencies,[700] lower costs to consumers,[701] and help

[670] New England State Agencies Comments at 21.

[671] R Street Institute Comments at 8.

[672] *Id.* at 8.

[673] EPRI Comments at 8.

[674] ACPA/SEIA Comments at 16–17.

[675] Tangibl Comments at 4–6.

[676] *Id.* at 5–6.

[677] R Street Institute Comments at 5–7.

[678] *Id.* at 3, 7.

[679] *See, e.g.,* Dominion Comments at 13; Entergy Comments at 2; Exelon Comments at 22; Indicated PJM Transmission Owners Comments at 17.

[680] Entergy Comments at 2.

[681] Indicated PJM Transmission Owners Comments at 15–16.

[682] Dominion Comments at 13; EEI Comments at 16–17.

[683] Exelon Comments at 22.

[684] Potomac Economics Comments at 4.

[685] New England State Agencies Comments at 21; OMS Comments at 13–14.

[686] New England State Agencies Comments at 22.

[687] The NERC Glossary defines ''Rated System Path Methodology,'' which includes an initial TTC from which the ATC is derived and is generally reported as specific transmission path capabilities. NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[688] PacifiCorp Comments at 5.

[689] Entergy Comments at 13–14.

[690] ITC Comments at 12.

[691] EDFR Comments at 6; Industrial Customer Organizations Comments at 27.

[692] PG&E Comments at 12.

[693] ACPA/SEIA Comments at 17.

[694] ISO–NE Comments at 10–11.

[695] Potomac Economics Reply Comments at 8.

[696] NYTOs Comments at 11.

[697] *See, e.g.,* APS Comments at 7; Dominion Comments at 4; Entergy Comments at 1; EEI Comments at 16; Exelon Comments at 22; Indicated PJM Transmission Owners Comments at 2; PacifiCorp Comments at 4; PG&E Comments at 12; SDG&E Comments at 3; WAPA Comments at 8.

[698] Exelon Comments at 22.

[699] ISO–NE Comments at 10; PacifiCorp Comments at 4.

[700] APS Comments at 7.

[701] ISO–NE Comments at 10; PacifiCorp Comments at 4; WAPA Comments at 8.

maintaining reliability and avoiding unnecessary load shed.[702] Emergency ratings have an extensive record of use and are a more accurate representation of the flow limits over shorter timeframes and are thus necessary to ensure just and reasonable wholesale rates.

293. First, as set forth under ''Obligations of Transmission Provider'' in *pro forma* OATT Attachment M, we require that transmission providers use emergency ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints. We define an ''emergency rating'' in *pro forma* OATT Attachment M as a transmission line rating that reflects operation for a specified, finite period, rather than reflecting continuous operation. An emergency rating may assume acceptable loss of equipment life or other physical or safety limitations for the equipment involved.[703] We adopt this emergency ratings requirement to ensure the accuracy of transmission line ratings, particularly during emergency operations. Emergency ratings are a critical input into determining transfer capabilities and congestion costs during emergency operations and can provide temporarily expanded operating flexibility to allow higher loading and higher operating limits on transmission facilities for a short time during unexpected tight system conditions, emergency events, or contingencies. Emergency ratings are also a critical input into the scheduling of transactions that can be executed under real-time operating constraints. Because real-time, unforeseen contingencies can occur that stress the system's transfer capabilities (*e.g.,* forced outages on generation or transmission), transmission providers operate their systems in normal conditions to be able to withstand such contingencies. Should such a contingency occur, transmission providers are thus prepared to redispatch resources. Dispatching and scheduling resources to accommodate such contingency events can cause a large increase in wholesale rates, due to congestion costs. More accurate emergency ratings (like more accurate transmission line ratings generally) will better reflect the near-term transfer capability of the system, more accurately reflect the cost of serving load, and avoid unnecessary transient congestion costs. For these reasons, we adopt the emergency ratings requirement as set forth in *pro forma* OATT Attachment M.

294. Second, we require that transmission providers use uniquely determined emergency ratings. Under this requirement, transmission providers must use emergency ratings that transmission owners determine uniquely from their determination of normal ratings.[704] This requirement ensures that transmission providers use emergency ratings that reflect that a transmission facility's transfer capabilities may differ for shorter periods of time; that is, transfer capabilities differ if calculated for use over a short period of time (*i.e.,* for emergency ratings) rather than for use over an indefinite period of time (*i.e.,* for normal ratings).

295. In response to commenters stating that the Commission should not require that emergency ratings be unique from normal ratings, we clarify that we are not requiring that emergency ratings be arbitrarily higher than normal ratings. Instead, we are requiring that emergency ratings be uniquely *determined,* meaning determined based on assumptions that reflect the specified, finite duration of emergency ratings, as distinct from the assumptions used to calculate normal ratings, which reflect a power transfer capability that can be maintained indefinitely. Consistent with the Commission's statements in the NOPR,[705] transmission owners will have discretion to determine the procedure used to calculate emergency ratings, so long as they do so in accordance with good utility practice and the other requirements in *pro forma* OATT Attachment M. Accordingly, a transmission provider may use an emergency rating equal to a normal rating, provided that both ratings were calculated uniquely using appropriate assumptions, sound engineering judgment, and good utility practice.

296. We agree with PacifiCorp's comment that the ability to use uniquely determined emergency ratings requires real-time and near real-time horizons contingency analysis tools that can handle variable limits (*i.e.,* normal rating for normal operating conditions, and emergency ratings in contingency conditions) and perform iterative simulations to calculate TTC on path ratings.[706] Such contingency analysis is already required under NERC Reliability Standards, including, *e.g.,* Reliability Standards TOP–001 and IRO–008, which require transmission providers and reliability coordinators to perform a real-time assessment at least once every 30 minutes to ensure that instability, uncontrolled separation, or cascading outages that could adversely impact the reliability of the interconnection will not occur.[707] Modifications to future-looking cases to increase flow, and to iteratively run contingency analysis, is common practice since system loading conditions change throughout the day. However, we agree that these tools require additional data points and simulation process modifications to observe the emergency rating of bulk electric system facilities, if not currently used.

297. Third, we require that emergency ratings also incorporate an adjustment for ambient air temperature and for daytime/nighttime solar heating, consistent with the AAR requirements for normal ratings. Based on the record, we find that the calculation of AARs for both normal and emergency ratings will enhance the accuracy of transmission line ratings and ensure just and reasonable wholesale rates. As commenters point out, congestion is often caused by post-contingency transmission flows that are modeled and managed as part of normal operations, and thus not requiring AARs to be applied to emergency ratings would inaccurately constrain even normal operations and prevent significant potential benefits of AAR implementation. Finally, we note that applying AARs to emergency ratings is consistent with the implementation of AARs in PJM, where nearly all emergency ratings are dependent on ambient air temperatures.[708]

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[702] Exelon Comments at 22.

[703] The NERC Glossary defines an ''Emergency Rating'' as: ''[t]he rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[704] As clarified below, consistent with our determination in Section IV.B.2.b.iii. on the role of the transmission owner and transmission provider in AAR implementation, transmission owners, not transmission providers, are responsible for calculating emergency ratings.

[705] NOPR, 173 FERC ¶ 61,165 at P 46 n.57.

[706] PacifiCorp Comments at 5–6.

[707] Reliability Standard TOP–001–5 R13 requires a transmission operator to perform a Real-Time Assessment at least once every 30 minutes. According to the NERC Glossary, a ''Real-Time Assessment'' is: ''[a]n evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: . . . Facility Ratings; and identified phase angle and equipment limitations.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[708] *See* PJM Ratings Information, *https://www.pjm.com/markets-and-operations/etools/*

298. As with the application of AARs to normal ratings, transmission owners have discretion to determine which specific electric system equipment has emergency ratings that are affected by ambient air temperatures, consistent with good utility practice and the requirements of *pro forma* OATT Attachment M.

299. Consistent with our determination in Section IV.B.2.b.iii on the role of the transmission owner and transmission provider in AAR implementation, we clarify that transmission owners, not transmission providers, are responsible for calculating emergency ratings. This responsibility is set forth in the NERC Reliability Standards, as well as in RTO/ISO foundational documents.[709] Nothing in this final rule changes that responsibility. In the non-RTO/ISO regions, this is generally not a concern because the transmission provider is usually the transmission owner. However, in the RTO/ISO regions, there is a distinction between transmission owners and transmission providers. Thus, in order to comply with this final rule, RTOs/ISOs—the transmission provider with the OATT on file—will need to rely on their member transmission owners to calculate emergency ratings and provide them to the RTO/ISO.[710] Additionally, unlike normal transmission line ratings, emergency ratings correspond to a specific duration. Thus, the duration of each uniquely determined emergency rating determined by a transmission owner must be specified and communicated by the transmission provider, consistent with our determination on the transparency and reporting requirements of transmission line ratings in Section IV.G.3 below.

300. Where the transmission provider is not the transmission owner (*e.g.,* RTOs/ISOs), we require the transmission provider to explain in its compliance filing, as part of its implementation of new *pro forma* OATT Attachment M, through what mechanism (tariff, membership agreement, etc.) the transmission owner has the obligation for making and communicating to the transmission provider the timely calculations and determinations related to emergency ratings (including any discretion in calculations).

301. In response to commenter requests for a minimum, maximum, or standardized emergency rating duration, we recognize that transmission owners use a range of durations and find that transmission owners are best situated to make judgments on the appropriate emergency rating duration based on the technical capabilities of the installed equipment, consistent with good utility practice, using sound engineering judgment, manufacturer guidance, and equipment reliability experience.

302. We recognize, as pointed out by some commenters, that emergency ratings can affect the safe operation and useful life of transmission facilities. However, as several commenters explain, most transmission equipment has the ability to withstand high currents for short periods of time without sustaining damage.[711] The requirement to implement uniquely determined emergency ratings simply requires that emergency ratings calculations be based on this existing ability, where it exists. In response to comments from MISO that the Commission allow transmission owners to establish reasonable and supported reliability margins,[712] as the Commission stated in the NOPR, transmission providers that find they need a reliability margin have existing Commission-approved mechanisms, such as the transmission reliability margin component of ATC, for establishing such a margin on a consistent and transparent basis.[713]

303. In response to Indicated PJM Transmission Owners and MISO Transmission Owners' concerns with Potomac Economics' analysis, we note that our findings in this final rule are not solely based on Potomac Economics' analysis. Rather, our rationale for adopting the requirement to implement uniquely determined emergency ratings, similar to the AAR requirements discussed above, is based on the finding that implementing uniquely determined emergency ratings will ensure that transmission line ratings are more accurate, that more accurate transmission line ratings will ensure wholesale rates more accurately reflect the cost of the wholesale service being provided, and, thus, that those wholesale rates are just and reasonable.

3. Equipment for Which Emergency Ratings Must Be Calculated

a. Comments

304. Exelon and APS note that they can and do calculate emergency ratings on equipment other than conductors and transformers.[714] APS notes that its use of emergency ratings often does not impact, and typically is not limited by, substation equipment.[715] Entergy states that emergency ratings cannot be used on many components of facilities.[716] However, Entergy explains that autotransformers can have emergency ratings about 25 to 30% over their normal rating for up to two hours.[717] Tangibl notes that different equipment may be limiting under different operating scenarios and that, while secondary and control components often have identical normal and emergency ratings, it is rare for relays to be the limiting element in PJM winter ratings.[718]

b. Commission Determination

305. As we determined in Section IV.A above, emergency ratings, like all transmission line ratings, must incorporate a set of electrical equipment ratings that collectively operate as a single electric system element (*e.g.,* transformers, relay protective devices, terminal equipment, and series and shunt compensation devices), and the most limiting component from that set will determine the transmission line rating. Consistent with our determination on the use of AARs in Section IV.B.1 above, we find that transmission providers must use uniquely determined emergency ratings on all conductors and all relevant transmission equipment, in order to ensure that transmission line ratings are accurate.

G. Transparency

1. NOPR Proposal

306. The Commission proposed in the NOPR to require transmission owners to share transmission line ratings for each period for which they are calculated and transmission line rating methodologies with their transmission provider(s), and, in regions served by an RTO/ISO, also with the market monitor(s) of that RTO/ISO.[719] The Commission preliminarily found that this requirement would afford transmission providers and market monitors more operational and situational awareness.[720]

307. The Commission also acknowledged that sharing transmission line ratings and transmission line rating methodologies with other, additional, interested parties would allow for

oasis/system-information/ratings-information.aspx (last visited Nov. 1, 2021).

[709] *See, e.g.,* Reliability Standards FAC–008–5, Requirement R3 and FAC–008–5, Requirement R6.

[710] *See supra* note 326.

[711] *See, e.g.,* Entergy Comments at 6–8; BPA Comments at 7; Exelon Comments at 21–23.

[712] MISO Comments at 26.

[713] NOPR, 173 FERC ¶ 61,165 at P 104.

[714] APS Comments at 7; Exelon Comments at 21.

[715] APS Comments at 7.

[716] Entergy Comments at 7.

[717] *Id.* at 7.

[718] Tangibl Comments at 3.

[719] NOPR, 173 FERC ¶ 61,165 at P 125.

[720] *Id.* P 126.

greater transparency and, in the case of transmission providers, may aid efforts to manage congestion along mutual seams and may be beneficial for the study of affected systems during the interconnection process.[721] The Commission thus sought comment on whether to require transmission owners to share, upon request, their transmission line ratings and transmission line rating methodologies with transmission providers other than the transmission owner's own transmission provider. The Commission also sought comment on whether to require transmission owners to make their transmission line ratings and transmission line rating methodologies available to other interested stakeholders, including by posting information on their OASIS page or other password-protected online forums.[722]

308. While the Commission did not propose new auditing requirements in the NOPR, the Commission reiterated that it would continue to conduct reviews of transmission line ratings as a component of broader tariff compliance audits.[723]

2. Comments

a. Increased Transparency Requirements for Transmission Line Ratings Methodologies

309. Many commenters express general support for the Commission's efforts to increase transparency surrounding transmission line ratings and methodologies.[724] MISO Transmission Owners argue that the transparency proposal in the NOPR seems reasonable, but should not be broadened, explaining that the transparency proposal in the NOPR balances the need for transparency for RTOs/ISOs and market monitors with the need for confidentiality.[725] Industrial Customer Organizations state that transparency is a prerequisite for stakeholders to independently evaluate the potential reliability benefits of more accurate transmission line ratings, for the Commission to ensure just and reasonable rates, to reduce the incentives and opportunities for transmission owners to understate or manipulate transmission line ratings, and for transmission providers to identify cost-effective congestion management solutions.[726] EDFR claims that increased transparency may result in more efficient and standardized transmission line rating methodologies while identifying outliers more quickly and that transparency encourages the use of a balanced, reasonable transmission line rating methodology, which should result in more accurate transmission line ratings.[727] OMS states that the Commission's regulations require transmission line rating transparency.[728] OMS further contends that transparency should be the default position and should only be restricted where demonstrably necessary.[729] EPSA states that transparent collection and disclosure of quality data is the lynchpin of an efficient transmission system.[730] Certain TDUs state that improved transparency of transmission line ratings processes will ultimately lead to a more efficient and cost-effective grid.[731] IID supports the Commission's proposed requirements and encourages the Commission to consider how such information can be shared in a timely manner, such that adjacent operators and users of the grid can account for current transmission line ratings in their weekly and day-ahead planning.[732]

b. Sharing Transmission Line Ratings and Methodologies With Transmission Providers and Market Monitors

310. Nearly all commenters support the proposal in the NOPR to require transmission owners to share transmission line ratings and methodologies with the relevant transmission provider and, in the case of transmission providers that are RTOs/ISOs, the relevant market monitor.[733] AEP and Exelon note that PJM posts actual transmission line ratings publicly.[734]

311. DC Energy contends that implementing AARs and DLRs and requiring RTOs/ISOs to post the transmission line ratings used for each constraint-binding interval for both the day-ahead and real-time markets is not an infeasible or unduly burdensome task.[735] DC Energy notes that ERCOT publishes every transmission line rating used for every constraint's binding interval for both its day-ahead and real-time markets on its market information system portal accessible by all market participants.[736]

312. Potomac Economics contends that the information shared must include the limiting element for each transmission line rating and the inputs necessary to replicate the transmission line rating calculation to monitor for transmission withholding, and that such information should be maintained in a database accessible by those with a role in monitoring, operating, and planning the transmission system.[737] EDFR supports a requirement that transmission owners provide information identifying the transmission line's limiting element.[738] New England State Agencies agree with the reforms proposed in the NOPR with a minimum of requiring disclosure of transmission line ratings and methodologies to all grid operators and market monitors.[739] New England State Agencies state such a requirement would allow verification of the existing transmission line ratings by independent authorities.[740] New England State Agencies assert that providing data to the RTO/ISO market monitor would allow the market monitor to verify the quality and accuracy of the information.[741] New England State Agencies contend that transmission owners may have an incentive to be overly conservative with transmission line ratings methodologies because there is no financial incentive for more efficient operation of existing transmission assets and there is significant incentive for transmission owners to build new transmission lines and substations and include these new assets in their rate base.[742] Because NYISO and PJM already require similar data disclosure, New England State Agencies claim that transmission owners can comply without undue difficulty with the proposed requirements and that there is no actual evidence in the record of any increased litigation in those regions where disclosure is common.[743]

313. NRECA/LPPC caution that their members do not believe the Commission

[721] *Id.* P 129.

[722] *Id.*

[723] *Id.* P 130.

[724] MISO Transmission Owners Comments at 19; Entergy Comments at 16; NRECA/LPPC Comments at 27–28; AEP Comments at 5; DC Energy Comments at 5; IID Comments at 7.

[725] MISO Transmission Owners Comments at 36.

[726] Industrial Customer Organizations Comments at 28–29.

[727] EDFR Comments at 7.

[728] OMS Comments at 17 n.57 (citing 18 CFR 37.6).

[729] OMS Reply Comments at 3–4.

[730] EPSA Comments at 3.

[731] Certain TDUs Comments 8.

[732] IID Comments at 7.

[733] AEP Comments at 8; CAISO DMM Comments at 3, 7–8; OMS Comments at 16; Exelon Comments at 23–24; DC Energy Comments at 5; Potomac Economics Comments at 16; IID Comments at 7; New England State Agencies Comments at 17–19; R Street Institute Comments at 3; SPP MMU Comments at 5; TAPS Comments at 23.

[734] AEP Comments at 8; Exelon Comments at 23–24.

[735] DC Energy Comments at 5.

[736] *Id.*

[737] Potomac Economics Comments at 16–17.

[738] EDFR Comments at 6.

[739] New England State Agencies Comments at 19.

[740] *Id.*

[741] *Id.* at 17–18.

[742] *Id.* at 18.

[743] *Id.* at 20.

should require RTOs/ISOs to develop and maintain comprehensive databases to document the limiting element of all transmission circuits and facilities in their regions, arguing that the benefit to consumers is unclear and that the NOPR does not support such a requirement.[744]

314. Only two commenters object to the proposed transparency requirements. Dominion states that requiring that transmission line ratings and methodologies be disclosed to the RTO/ISO market monitor is unwarranted because transmission line ratings are primarily reliability tools and are effectively overseen by NERC.[745] Dominion states that it already provides transmission line ratings to PJM and PJM makes them publicly available.[746] While Dominion does not object to continuing these practices, Dominion does object to providing its transmission line rating methodology to the PJM market monitor, which Dominion argues has no oversight over the operation of the PJM transmission system.[747] Separately, ITC argues that requirements to make all transmission line ratings available to the RTOs/ISOs, market monitor, and other stakeholders would be unduly burdensome.[748] ITC states that only a small number of transmission lines contribute to congestion and that regular reporting may increase the probability of inconsistencies between ITC's internal databases and those used for external data requests.[749] ITC therefore requests that the final rule require transmission owners to provide such data only upon request. ITC argues that RTOs/ISOs and market monitors should use shared transmission line ratings for informational purposes only and not for standardization purposes.[750]

c. Transmission Providers Sharing Transmission Line Ratings and Methodologies With Any Transmission Provider

315. Several commenters support a requirement for transmission providers to share, upon request, transmission line ratings and methodologies with any transmission provider.[751] APS states that this sharing of information is essential to ensure security in APS's transmission operator area.[752] MISO states that, in addition to the proposed transparency requirements in the NOPR, sharing the same information with neighboring transmission providers that share a seam with MISO is needed.[753] MISO asserts that such sharing of these transmission line ratings would be necessary for both tie lines and interregional congestion management, useful for reliability studies involving the neighboring regions, consistent with other coordination practices, and subject to confidentiality restrictions to control dissemination.[754] Similarly, Vistra argues that the Commission should clarify that transmission providers must share AAR information with neighboring transmission providers because transmission line rating calculations typically consider loop flows.[755] Vistra explains that, logistically, this information sharing could take many forms, including direct data pushes between transmission providers or publishing such information on OASIS sites and that the Commission need not dictate a particular information sharing method.[756]

d. Sharing Transmission Line Ratings and Methodologies With Other Entities

316. Some commenters support requiring the sharing of transmission line ratings and methodologies with entities other than transmission providers and market monitors.[757] For example, WATT contends that transmission line rating methodologies need to be shared with all transmission customers.[758] R Street Institute argues that the NOPR proposal would provide insufficient transparency and that, ideally, transmission line ratings and methodologies would be available to a broader set of market participants and state commissions as well.[759] OMS similarly asserts that all stakeholders should be able to see transmission line ratings and that the market monitor and MISO should be granted complete transparency into the methods used to create these transmission line ratings, recognizing that the regional entities are strictly focused on reliability.[760]

317. TAPS urges the Commission to allow interested persons to access transmission line ratings and methodologies through password-protected interfaces, such as OASIS, such that if a transmission customer has concerns about the impact of a constraint, it should be able to obtain information on the transmission line ratings and methodologies used to establish such ratings. TAPS contends that doing so would enable transmission customers to better understand what is driving the prices that they are required to pay.[761] APS states it would not support posting transmission line ratings and methodologies on OASIS, but would support other password-protected online forums where access could be controlled.[762] To expand transmission line rating information and reduce the information gap, ACPA/SEIA suggests that there are several options, including expanding the FERC Form 715 reporting requirements or making this information available on OASIS sites.[763] DC Energy asks that the Commission require transmission owners outside of organized electricity markets to post transmission line ratings and methodologies on their OASIS pages or another password-protected online forum.[764]

318. Clean Energy Parties contend that requiring transmission owners to disclose their transmission line ratings and methodologies to RTOs/ISOs and market monitors but not share with the broader public is unduly discriminatory.[765] Exelon requests flexibility to allow transmission providers, like PJM, to publish transmission line ratings consistent with existing practices.[766] ACPA/SEIA contends that the Commissions should require that all market participants have comparable information on near-term transmission service.[767] ACPA/SEIA argues that because near-term transmission service information would only be available to transmission owners, RTOs/ISOs, and market monitors, there would be a discriminatory ''information gap,'' putting transmission customers at a disadvantage by not being able to easily identify optimal interconnection locations and not being able to understand or reproduce AAR or DLR congestion analyses.[768]

319. New England State Agencies argue that it is important to states that

[744] NRECA/LPPC Comments at 27–28.

[745] Dominion Comments at 14–15.

[746] *Id.*

[747] *Id.*

[748] ITC Comments at 13.

[749] *Id.*

[750] *Id.*

[751] APS Comments at 8; PacifiCorp Comments at 3; MISO Comments at 29; EPSA Comments at 3; Exelon Comments at 27; IID Comments at 7.

[752] APS Comments at 8.

[753] MISO Comments at 29.

[754] *Id.*

[755] Vistra Comments at 7–8.

[756] *Id.*

[757] APS Comments at 9; Clean Energy Parties Comments at 14; EPSA Comments at 3; Exelon Comments at 28–29; EDFR Comments at 7; New England State Agencies Comments at 20; OMS Comments at 16; R Street Institute Comments at 3; TAPS Comments at 24; WATT Comments at 14.

[758] WATT Comments at 14.

[759] R Street Institute Comments at 3.

[760] OMS Comments at 16.

[761] TAPS Comments at 24.

[762] APS Comments at 9.

[763] ACPA/SEIA Comments at 19–20.

[764] DC Energy Comments at 5–6.

[765] Clean Energy Parties Comments at 14.

[766] Exelon Comments at 28–29.

[767] ACPA/SEIA Comments at 19–20.

[768] *Id.* at 18–19.

have relied on competitive procurements for certain types of energy development needs to have access to transmission line ratings and methodologies.[769] According to New England State Agencies, the Commission's requirement in Order No. 1000 that transmission providers consider public policy transmission needs as part of regional transmission planning processes would be materially aided by allowing open access to transmission line ratings and similar data.[770] New England State Agencies state that password protections and non-disclosure agreements can be used in protecting confidential information in a wide variety of circumstances if there is concern about loss of confidential business information.[771]

320. Conversely, several commenters oppose further sharing beyond transmission providers and, where appropriate, market monitors. PacifiCorp states that it strongly opposes making its transmission line ratings broadly available to stakeholders or posting such information to OASIS due to the potential for reliability risks and unclear benefits.[772] MISO Transmission Owners state that there appears to be no need for transmission line ratings to be public because: (1) ATC is made available to the public; (2) transmission line ratings are only one of many inputs into ATC; and (3) ATC is made available on OASIS pages.[773] PG&E recommends against requiring transmission owners and transmission providers to post real-time transmission line ratings on their OASIS pages, noting that transmission line rating methodologies should also not be disclosed to any parties other than the Commission and other transmission providers.[774] Indicated PJM Transmission Owners argue that requiring transmission line ratings and methodologies to be made public would be unnecessary in PJM, given the existing information is made available.[775] EEI recommends that the Commission not require transmission owners and transmission providers to post real-time transmission line ratings on their OASIS pages but instead provide only the methodologies for determining AARs and seasonal line ratings.[776]

e. Auditing, Enforcement, and Litigation

321. Several commenters note that NERC already audits transmission line ratings and argue that any transmission line ratings verification or transmission line ratings auditing performed by market monitors would be unnecessary or harmful.[777] Exelon states that, were a market monitor to allege improper transmission line rating calculations which NERC has already approved, there could be dueling determinations and confusion and potential inconsistency with FPA section 215, which specifies that NERC, as the Electric Reliability Organization, is responsible for enforcing mandatory Reliability Standards.[778] Exelon, AEP, and MISO Transmission Owners allege that calculating transmission line ratings requires a degree of engineering judgment, reflective of transmission owners' operational experience, risk tolerance, and local knowledge.[779] Exelon argues that market monitors lack this knowledge.[780] AEP argues that RTOs/ISOs should have no role beyond applying submitted transmission line ratings.[781] EEI asks that the Commission emphasize that any final rule would not change the audit and enforcement construct already in place and that the audits should not specifically review the transmission line rating methodologies and assumptions.[782] MISO Transmission Owners explain that it may not present a problem for RTOs/ISOs and market monitors to identify computational transmission line ratings errors, but RTOs/ISOs and market monitors should not be permitted to second-guess transmission line rating methodologies.[783] Indicated PJM Transmission Owners explain that the functions of the PJM market monitor are limited to those items identified by Attachment M of the PJM OATT, requiring the market monitor to assess the competitiveness of the ''PJM markets, but not monitor transmission line ratings as it does not have the requisite expertise or reliability authority.[784] Indicated PJM Transmission Owners disagree with the Commission's statement that the NERC Reliability Standards may be insufficient to ensure accurate transmission line ratings.[785] Sunflower argues that the Commission should require specific measures for transmission providers to monitor the impact of AARs and seasonal line ratings on the safety and reliability of the electric system.[786]

322. Some commenters argue for further oversight and expansion of the auditing of transmission line ratings and methodologies. Potomac Economics recommends that the Commission require some form of independent oversight, verification, and monitoring of the transmission line ratings calculated and used in non-RTO/ISO areas.[787] Potomac Economics contends that it is important to clarify that transmission line rating information that underlies curtailments under transmission line ratings or joint operating agreements be available to other transmission providers, reliability coordinators, or RTOs/ISOs that are affected by the curtailments.[788] Ohio FEA recommends that PJM routinely review submitted transmission line ratings and the methodologies used in their development; otherwise, Ohio FEA continues, the benefits associated with implementing AARs may prove to be illusory if the transmission line ratings themselves are not based on objective and accurate criteria.[789] Ohio FEA insists that the PJM market monitor must be granted the authority to review transmission line ratings and take corrective actions deemed necessary if the market monitor concludes that a transmission owner's transmission line ratings are inaccurate, consistent with the market monitor's role as defined in Attachment M of the PJM OATT.[790]

323. Many commenters express concern over potential litigation regarding transmission line ratings and methodologies (though AEP states that the proposed requirements in the NOPR adequately mitigate litigation risks).[791] EEI argues that third parties should not be able to litigate or dispute transmission line ratings or methodologies.[792] Exelon caveats that its position supporting additional transparency is contingent on the Commission ensuring that the enhanced transparency does not result in constant litigation from market participants, provided such transmission line ratings

[769] New England State Agencies Comments at 20.

[770] *Id.*

[771] *Id.*

[772] PacifiCorp Comments at 4.

[773] MISO Transmission Owners Comments at 37.

[774] PG&E Comments at 12.

[775] Indicated PJM Transmission Owners Comments at 23–24.

[776] EEI Comments at 13.

[777] Exelon Comments at 24; AEP Comments at 8–9; EEI Comments at 13–14; Indicated PJM Transmission Owners Comments at 17–18.

[778] Exelon Comments at 25–26.

[779] *Id.* at 26–27; AEP Comments at 9; MISO Transmission Owners Comments at 37–38.

[780] Exelon Comments at 26–27.

[781] AEP Comments at 9.

[782] EEI Comments at 13–14.

[783] MISO Transmission Owners Comments at 37–38.

[784] Indicated PJM Transmission Owners Comments at 22–23.

[785] *Id.* at 19–21.

[786] Sunflower Comments at 4.

[787] Potomac Economics Comments at 18; *see also* Potomac Economics Reply Comments at 12.

[788] Potomac Economics Comments at 18.

[789] Ohio FEA Comments at 5–6.

[790] *Id.* at 6.

[791] AEP Comments at 10.

[792] EEI Comments at 13–14.

and calculations are reasonably accurate at reflecting a transmission facility's power transfer capability, as transmission line ratings are fundamentally a reliability concept.[793] MISO Transmission Owners argue that transparency requirements beyond those proposed in the NOPR that result in an increase in disputes and litigation surrounding transmission line ratings and/or methodologies would reduce the benefits of the proposed reforms. MISO Transmission Owners therefore contend that the Commission should clarify its statement in the NOPR that the proposed increased transparency will allow RTOs/ISOs and market monitors to verify transmission line ratings.[794] Similarly, Indicated PJM Transmission Owners warn that further transparency disclosure requirements would result in costly and time consuming litigation, and thereby increased burdens on transmission owners and the Commission, as a result of arguments from market participants soliciting changes designed to benefit themselves and negatively affect others. Indicated PJM Transmission Owners stress that this would be inappropriate because transmission line ratings are complex calculations, based on many different factors, including local assets, engineering judgment, and how assets are traditionally operated, and therefore litigation with the Commission would be inappropriate.[795] ITC requests that the final rule clarify that incorrect transmission line ratings due to changes in weather or unintentional errors in data that were submitted in good faith should not create additional legal or regulatory liability for transmission owners. ITC states that it would not benefit from such errors since it is primarily concerned with reliability and does not participate in markets.[796] Conversely to these commenters, AEP expresses that the Commission's NOPR strikes the right balance between providing transparency without creating risks of unnecessary litigation for transmission owners if transmission line ratings cannot be precisely replicated by third parties.[797] Furthermore, DC Energy contends that the need for disclosure outweighs transmission owners' claims of confidentiality or fear of potential litigation.[798]

[793] Exelon Comments at 29.

[794] MISO Transmission Owners Comments at 37–38 (citing NOPR, 173 FERC ¶ 61,165 at P 127).

[795] Indicated PJM Transmission Owners Comment at 24.

[796] ITC Comments at 16.

[797] AEP Comments at 9–10.

[798] DC Energy Comments at 5.

f. Posting of Exceptions to OASIS

324. EPSA asks that transmission providers be required to disclose (potentially via OASIS) which transmission lines they deem as not benefitting from an AAR or seasonal line rating. EPSA also asks that transmission providers be required to disclose the reasons for making those determinations to thereby enable RTOs/ISOs and market monitors to verify those decisions. Moreover, EPSA asks that these decisions be evaluated at least every five years to ensure AAR-exempt transmission lines should continue to qualify for exceptions.[799]

g. Other Transparency Topics

325. ISO–NE states that to comply with the NOPR's proposed transparency requirements, it would need to modify Planning Procedure No. 7, Procedures for Determining and Implementing Transmission Facility Ratings (PP7) as New England Transmission Owners are required to follow the PP7 procedures to determine transmission line rating methodologies.[800] ISO–NE requests that the Commission allow for sufficient time for the PP7 changes to make their way through the applicable processes for the transmission owners to implement those changes and then provide new transmission line ratings to ISO–NE and its market monitor in the manner contemplated in the NOPR.[801]

326. NRECA/LPPC recommend that any measures in the final rule to improve the transparency of transmission line ratings should be consistent with the requirements of existing mandatory NERC Reliability Standards, including Critical Infrastructure Protection (CIP) Standards, as well as requirements to protect Critical Electric/Energy Infrastructure Information (CEII).[802]

327. OMS suggests that the Commission could revisit the data it currently collects in FERC Form 715 to better analyze how the data already being collected can be used to understand some transmission owners' transmission line ratings and methodologies but not others.[803] OMS also suggests that the Commission consider a comment and response process between transmission owners, transmission providers, and market monitors to provide additional oversight into the appropriateness of transmission line ratings throughout the bulk power system.[804]

[799] EPSA Comments at 4.

[800] ISO–NE Comments at 11.

[801] *Id.* at 11.

[802] NRECA/LPPC Comments at 3.

[803] OMS Comments at 17.

328. Clean Energy Parties contend that RTOs/ISOs should be required to discuss with stakeholders and report to the Commission how winter capacity deliverability differs from summer and identify possible reliability improvements or cost savings arising from those differences.[805]

329. Some commenters assert a connection between transparency around transmission line ratings and FTR markets. EDFR states that transparency provides market participants with a better understanding of how transmission line ratings could change over time while helping to anticipate congestion, hedge congestion, and participate in the FTR markets.[806] DC Energy states that market participants, particularly those that purchase and sell FTRs, need transparency in order to critically analyze and address market inefficiencies.[807] DC Energy contends that FTR market participants will require transparent transmission line rating and methodology information in order to accurately forecast congestion.[808] DC Energy asserts that transparency is essential for the transition to AARs and DLRs because, without adequate transparency, AARs and DLRs could actually make congestion hedges less accurate. This is because, according to DC Energy, AARs and DLRs will cause transmission line ratings to change without advance notification and, in times of adverse system conditions, AARs and DLRs will more accurately reflect the fact that less transfer capability is available.[809]

3. Commission Determination

330. Upon consideration of the comments received, we adopt the NOPR proposal to require public utility transmission owners to share their transmission line ratings for each period for which they are calculated and transmission line rating methodologies with their transmission providers and with market monitors in RTOs/ISOs. We acknowledge situations in which the transmission owner and transmission provider are the same entity, and we expect that in such cases compliance with this final rule's transparency requirements will be simple in the sense that the transmission provider will not have to rely on a separate transmission

[804] *Id.*

[805] Clean Energy Parties Comments at 12.

[806] EDFR Comments at 7.

[807] DC Energy Comments at 3–4.

[808] *Id.* at 4.

[809] *Id.* at 5.

owner to provide the transmission line ratings and methodologies. We also adopt three additional transparency requirements. First, we require each transmission provider to share transmission line ratings and methodologies with any transmission provider(s) upon request. Second, we require each transmission provider to maintain a database of its transmission line ratings and methodologies on the transmission provider's OASIS site, or other password-protected website. We require that this database be in such a form that can be accessed by all parties with OASIS access or access to the password-protected website. The database should archive and allow for querying of all current transmission line ratings and all transmission line ratings used in the past five years. Third, we require transmission providers to post on OASIS, or other password-protected website, which transmission lines qualify for an exception to the AAR or seasonal line rating requirements and the reasons why such transmission lines qualify for an exception.

a. Transmission Owners Sharing Ratings and Methodologies With Transmission Providers and, Where Applicable, Market Monitors

331. We find that requiring public utility transmission owners to share transmission line ratings and methodologies with their transmission providers and, in RTOs/ISOs, market monitors, will help remedy unjust and unreasonable wholesale rates caused by inaccurate transmission line ratings. We affirm the Commission's preliminary finding in the NOPR that this requirement will enhance operational and situational awareness by ensuring that transmission providers know the effect that changes in ambient air temperature would have on transmission line ratings within their system.[810] Further, as the Commission explained in the NOPR, this requirement will provide transmission providers and market monitor(s) the information necessary to verify the resulting transmission line ratings and to identify potential errors.[811]

332. We agree with EDFR that the transparency-increasing effects of requiring public utility transmission owners to share transmission line ratings and methodologies with their transmission provider(s), and with market monitors in RTOs/ISOs, will result in more accurate transmission line ratings. By sharing transmission line ratings and methodologies with transmission providers and market monitors, these parties will be better positioned to develop automated screens and other techniques to detect corrupted data or other errors that could negatively impact operations or planning processes.

333. We disagree with arguments that because transmission line ratings are reliability tools that are effectively overseen by NERC, additional transparency requirements are unnecessary. While transmission line ratings are an important reliability tool, we find (as discussed above in Section III) that transmission line ratings directly affect wholesale rates. Further, commenters have not explained why a relationship between transmission line ratings and reliability would represent a reason not to adopt the transparency requirements. We also disagree with comments that requiring public utility transmission owners to share transmission line ratings and methodologies with their transmission provider(s) and with market monitors in RTOs/ISOs would be unduly burdensome and could create inconsistencies between transmission line ratings used internally by transmission owners and transmission line ratings used by transmission providers. We recognize comments from New England State Agencies noting that such disclosure is already common in some markets, and that this indicates that transmission owners can comply without undue difficulty.[812] Moreover, we think it is unlikely that sharing of transmission line ratings would create inconsistencies in the manner described by ITC. On the contrary, we believe that a benefit of this requirement would be to identify and promote the resolution of such inconsistencies.

334. Finally, we reiterate that the Commission will continue to conduct reviews of transmission line ratings as a component of broader tariff compliance audits[813] and that this final rule does not change the auditing requirements or authorities of any entity.

b. Transmission Providers Sharing With Any Transmission Provider(s) Upon Request

335. As set forth under ''Obligations of Transmission Provider'' in *pro forma* OATT Attachment M, we further require transmission providers to share transmission line ratings and methodologies with any transmission provider(s) upon request and in a timely manner. We agree with commenters that contend that this requirement is necessary because transmission operators often consider the effect that power flows on their transmission lines will have on other transmission providers' transmission lines, and transmission providers will need transmission line ratings on other systems to evaluate these effects properly. While we acknowledge that Vistra's example involved neighboring transmission providers, we do not limit this requirement to neighboring transmission providers, as such power flow effects can sometimes extend beyond neighboring transmission providers (particularly if a neighboring transmission provider's system is geographically/electrically narrow where it approaches another transmission provider's system). Further, we agree with commenters that this information sharing could take several forms, and that the Commission need not dictate an information sharing method. However, any such information sharing method should be sufficient to accommodate the reasonable business needs of the other transmission provider(s) (*e.g.,* to allow the other transmission provider(s) to process transmission service requests in a timely manner).

c. Transmission Providers Sharing With Other Entities

336. We further require each transmission provider to maintain a database of their transmission owners' transmission line ratings and methodologies on the password-protected section of their OASIS site or other password-protected website. This requirement will allow other entities (beyond transmission providers and market monitors) that are able to access the password-protected section of the transmission provider's OASIS site or other password-protected website to have access to the database of transmission line ratings and methodologies. This requirement is set forth under ''Obligations of Transmission Provider'' in *pro forma* OATT Attachment M. We agree with commenters that making transmission line ratings and methodologies available to a broader range of stakeholders will amplify the expected benefits of the proposal included in the NOPR, further facilitate more accurate transmission line ratings, and facilitate more cost-effective decisions by market participants and, as described by New England State Agencies, state agencies. For example, without accurate

[810] NOPR, 173 FERC ¶ 61,165 at P 127.

[811] *Id.*

[812] New England State Agencies Comments at 20.

[813] Many commenters use the term ''audit'' to describe activities by market monitors and other entities that the Commission's rules do not define as auditing. We note that the Commission retains its authority to formally audit for compliance with OATTs and other Commission-jurisdictional rules.

transmission line rating information, market participants may be unable to make informed siting decisions regarding where to build generation or where to site load. Also, without accurate transmission line rating information, market participants may be unable to accurately predict and hedge against transmission congestion. Moreover, as New England State Agencies argue, access to transmission line ratings and transmission line rating methodologies is important to states that have relied on competitive procurements for certain types of energy development needs.[814] We acknowledge that requiring this information to be placed on OASIS or other password-protected website presents a burden on transmission providers, but we find that the benefits of increased transparency are likely to outweigh any such burden.

337. Beyond enhancing the general benefits of the transmission line rating requirements adopted herein, we find that transparency for transmission line ratings and methodologies will also be particularly beneficial to wholesale market participants trying to manage uncertainty. With respect to FTR market participants, for example, we agree with DC Energy that, because FTR payouts are based on congestion costs that change with transmission line ratings, sharing transmission line ratings and methodologies with a wider range of stakeholders will help establish efficient FTR market price discovery by improving FTR market participants' understanding of certain drivers of congestion, and allow such market participants to build such understanding into their FTR bids and offers.[815]

338. We disagree with arguments contending that requiring each transmission provider to maintain a database of each transmission owner's transmission line ratings and methodologies on the transmission provider's OASIS site or other password-protected website will lead to unjust and unreasonable wholesale rates or other undesirable outcomes. Specifically, we are not persuaded by comments that making transmission line ratings and methodologies available to a broader range of stakeholders could result in increased litigation whereby customers initiate complaints against transmission owners regarding the underlying assumptions used to calculate transmission line ratings or regarding the calculations themselves. There is a lack of evidence of increased litigation in those regions where disclosure is already common, as noted by the New England State Agencies.[816] Moreover, commenters have not identified any complaints or other such litigation about transmission line ratings related to this existing requirement. Further, consistent with the Commission's statement in the NOPR,[817] we intend to give latitude to transmission owners to determine their transmission line ratings in accordance with good utility practice. Finally, we note that section 37.6 of the Commission's regulations already requires transmission providers, upon customer request, to make all data used to calculate ATC for any constrained posted path publicly available on OASIS. This includes the limiting elements and the cause of the limit (*e.g.,* thermal, voltage, stability), as well as load forecast assumptions.[818] The posting requirement for transmission line ratings and methodologies is consistent with that existing requirement.

339. Transmission line ratings stored in the required database must include a full record of all transmission line ratings, both as used in real-time operations, and as used for all future market periods for which transmission service is offered. For example, a transmission provider that implements AARs calculated for the next 240 hours (for use in evaluating near-term transmission service requests), re-calculates such AARs every hour, and calculates seasonal line ratings (for use in evaluating longer-term transmission service requests) would keep records of its transmission line ratings in the following manner. With respect to its AARs, such a transmission provider would insert records into its transmission line rating database each hour, shortly after calculation of its AARs. In each such hour, the transmission provider would insert a separate AAR record into its database for: (1) Each transmission line; (2) each current and forward hour for which transmission line ratings are calculated (at least one rating for each of the 240 hours in the next 10 days); and (3) each rating type (normal and each type of emergency rating (*e.g.,* 30 minute, one hour, etc.)). If such a transmission provider had 1,000 transmission lines and four rating types (*e.g.,* normal, 30 minute, one hour, and four hour), then each hour the transmission provider would insert into its database 960,000 new AAR records ($1000 \times 240 \times 4$).[819] Furthermore, such a transmission provider would also maintain in its database records of which seasonal line ratings (for use in evaluating longer-term transmission service requests) or other types of transmission line ratings (as permitted under *pro forma* OATT Attachment M, *e.g.,* static line ratings) were in effect at which times for each transmission line.[820] Finally, while we are not requiring implementation of DLRs at this time, we note that if a transmission provider implements DLRs on any of its transmission lines, then under this requirement it would document the DLR ratings on such transmission lines in the same way that it documents its AAR ratings, as discussed above.

340. Transmission providers must maintain in their database records of which transmission line ratings and methodologies were in effect at which times over at least the previous five years. This five-year period of record retention is consistent with other document retention periods required for OASIS postings.[821] Each record in the database must indicate to which transmission line the record applies, and the date and time the record was entered into the database. Finally, the database must be maintained such that users can view, download, and query data in standard formats, using standard protocols.

d. Transmission Providers Posting Exceptions and Temporary Alternate Ratings to OASIS

341. Finally, in response to EPSA, we require transmission providers to make postings to the database of transmission line ratings on their OASIS site or other password-protected website (discussed above in Section IV.G.3.d) documenting

[814] New England State Agencies Comments at 20.

[815] DC Energy Comments at 3. While different RTOs/ISOs have different names for these financial products, such as financial transmission rights, transmission congestion rights, congestion revenue rights, etc., for simplicity here we will use FTRs to refer to any such financial product in the RTOs/ISOs.

[816] New England State Agencies Comments at 20.

[817] NOPR, 173 FERC ¶ 61,165 at PP 98, 105.

[818] *See* 18 CFR 37.6.

[819] We note that transmission providers may determine that there are more efficient ways of storing the AAR data than presented in the example above, and such approaches may be acceptable as long as users of the database can readily identify which such ratings (including for the operational hour and any forward hours) were in effect for which transmission lines at which times.

[820] We do not specify exactly how records of seasonal or static line ratings should be stored in the line rating database. However, such longer-term transmission line ratings do not necessarily need to be stored on an hourly basis, so long as users of the database can readily identify which such ratings were in effect for which transmission lines at which times. We note that some transmission lines may not have any AAR ratings at all, where permitted under *pro forma* OATT Attachment M, and so may only have ratings such as seasonal or static line ratings.

[821] 18 CFR 37.6 (Information to be posted on the OASIS).

any uses of exceptions (under the ''Exceptions'' paragraph of *pro forma* OATT Attachment M) or temporary alternate ratings (under the ''System Reliability'' section of *pro forma* OATT Attachment M). This requirement to post exceptions and temporary alternate ratings on OASIS or other password-protected website is set forth in *pro forma* OATT Attachment M. We require that such postings document the nature of and basis for each such exception or alternate rating, as well as the date(s) and time(s) of initiation and (if applicable) withdrawal for the exception or the alternate rating.

342. We find that the requirement for such postings will help ensure proper transparency for the use of such exceptions and temporary alternate ratings, similar to the transparency provided through other posting requirements of this final rule.[822] Furthermore, these postings of exceptions will support the fulfillment of and verification of compliance with the requirement, discussed above in Section IV.D.3, that exceptions be re-evaluated at least every five years.

343. Similar to the benefits discussed above in Section IV.G.3.c related to requiring transmission line ratings and methodologies to be available on OASIS sites or other password-protected websites, we find that this requirement for exceptions postings will enable and support verification of the accuracy of transmission line ratings.

H. Other Miscellaneous Issues

1. Comments

344. Some commenters argue for incentives to encourage DLR deployment. Specifically, NYTOs and ACORE request financial incentives for AARs and DLRs under FPA section 219.[823] ACPA/SEIA contend that the Commission should consider accelerated cost recovery of depreciation to implement sensor-based DLRs.[824] Although WATT urges the Commission to address the misalignment of incentives to adopt DLRs or other grid-enhancing technologies, WATT asserts that the Commission should not grant incentives for DLRs in this docket.[825]

345. MISO contends that while AARs may provide incremental transfer capability on existing transmission lines, they cannot solve significant long-range transmission problems.[826] Moreover, EEI argues that chronic congestion should be reviewed and alleviated in the transmission planning process.[827]

2. Commission Determination

346. In response to arguments about incentives for advanced transmission technology deployment, we find such arguments about incentivizing certain technology to be outside the scope of this proceeding, which is limited to the Commission's proposed requirements for transmission line ratings.

347. In response to MISO's assertion that AARs cannot solve significant long-range transmission problems, we find transmission planning and development to be outside the scope of this proceeding. For the same reason, we find EEI's claim that chronic congestion should be reviewed and alleviated in the transmission planning process to be outside the scope of this proceeding. We note that the Commission recently initiated a proceeding to examine a broad range of transmission-related issues, including regional transmission planning, in its July 2021 Advance Notice of Proposed Rulemaking in Docket No. RM21–17–000.[828]

I. Compliance

1. NOPR Proposal

348. In the NOPR, the Commission proposed to require each transmission provider to submit a compliance filing within 60 days of the effective date of any final rule. The Commission clarified that this compliance deadline would be for transmission providers to submit proposed AAR tariff changes, RTOs/ISOs to submit proposed tariff changes designed to maintain systems and procedures needed to allow for the use of AARs and DLRs, transmission owners to submit tariff changes implementing the proposed transparency reforms, or for each entity to otherwise comply with any final rule. As justification, the Commission acknowledged that implementing the reforms required by any final rule in this proceeding may be complex, but preliminarily found that implementation of these reforms is important to ensure wholesale rates are just and reasonable.

349. Recognizing the complexity of the proposed AAR requirements, the Commission proposed a staggered implementation approach that would prioritize implementation on historically congested transmission lines (within one year from the date of the compliance filing), but further proposed a less aggressive implementation of AARs on all other transmission lines (within two years from the date of the compliance filing). For the proposed DLR requirements and proposed transparency requirements, the Commission proposed that tariff changes filed in response to a final rule in this proceeding would become effective within one year from the date of the compliance filing.

350. The Commission recognized that some transmission providers may have provisions in their existing OATTs or other document(s) subject to the Commission's jurisdiction that the Commission has deemed to be consistent with or superior to the *pro forma* OATT or that are permissible under the independent entity variation standard or regional reliability standard. Where these provisions would be modified, the Commission proposed to require transmission providers to either comply with the proposed requirements or demonstrate that these previously approved variations continue to be consistent with or superior to the *pro forma* OATT as modified by the proposed requirements or demonstrate that these previously approved variations are just and reasonable and meet the purpose of the final rule under the independent entity variation standard or regional reliability standard.[829]

2. Comments

351. Comments on the proposed compliance and implementation timelines came predominately from RTOs/ISOs and transmission owners requesting more time. Most commenters suggest a minimum 120-day compliance deadline,[830] but some suggest a minimum 180-day compliance deadline,[831] and others suggest a minimum 90-day compliance deadline.[832] Most transmission owners commenting argue that three years is needed to implement AARs on priority transmission lines;[833] however,

[822] *See,* 18 CFR 37.6 (Information to be posted on the OASIS).

[823] NYTOs Comments at 2; ACORE Comments at 3–4.

[824] ACPA/SEIA Comments at 11.

[825] WATT Comments at 16.

[826] MISO Comments at 2, 6–7.

[827] EEI Comments at 6.

[828] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 86 FR 40266 (July 27, 2021), 176 FERC ¶ 61,024 (2021).

[829] NOPR, 173 FERC ¶ 61,165 at P 132.

[830] EEI Comments at 19; NRECA/LPPC Comments at 28–29; MISO Transmission Owners Comments at 38–39; SCE Comments at 2; SDG&E Comments at 1–2; APS Comments at 10; WFEC Comments at 1; Southern Company Comments at 6–7; MISO Comments at 31; ISO–NE Comments at 12.

[831] CAISO Comments at 2; NYISO Comments at 18.

[832] SPP Comments at 16; PacifiCorp Comments at 7.

[833] EEI Comments at 18; NRECA/LPPC Comments at 28–29; MISO Transmission Owners Comments at 22–23; SCE Comments at 2; SDG&E Comments at

PacifiCorp suggests that two years would be sufficient, while PG&E suggests that at least four years would be needed.[834] NYTOs, WAPA, and BPA also contend that the proposed implementation timeline is insufficient but do not proposed an alternative schedule.[835] Some commenters support the proposed timeline.[836] Industrial Customer Organizations recommend that the proposed implementation timeline be halved.[837]

352. Arguing that one year is insufficient to implement AARs on historically congested transmission lines, MISO Transmission Owners explain that their experience is that, on average, it takes several years to implement AARs on even a subset of transmission lines.[838] According to MISO Transmission Owners, at least three years is needed for AAR implementation because of all the steps needed to implement AARs, including developing and updating the transmission line rating methodologies, analyzing historical weather information, identifying limiting elements, developing a transmission line ratings database, updating the transmission management system, testing the transmission line ratings, and linking the transmission owners' transmission management system to the RTO/ISO EMS, all while maintaining cybersecurity standards.[839] EEI similarly states that it could take up to two years just to upgrade operating and data systems to create the capability to produce and update AAR calculations.[840] Southern Company and SCE support EEI's comments.[841] Specifically, Southern Company requests at least 120 days for compliance filings and at least three years for AAR implementation.[842] SCE claims that the Commission's proposed implementation schedule is not realistic.[843]

353. PacifiCorp states that implementation of the NOPR proposal would be complicated as it would require updates to PacifiCorp's EMS, SCADA, and other software that communicates transmission line ratings with CAISO, RC West, and other transmission providers.[844] APS argues that adequate time is needed to develop the business requirements for the software vendors and that APS will have to work with multiple software vendors to comply with the TLR provisions as currently delineated in the NOPR.[845] NRECA states that its members need a minimum of three years to implement AARs on all their transmission lines in order to identify, document, and implement the necessary system and process changes.[846] Presenting a five year implementation approach, PG&E states that AAR implementation will require significant initial investments and that the Commission should allow for sufficient time for RTOs/ISOs and transmission owners to collaborate to develop new communication systems and new processes for determining and operating with AARs.[847]

354. ITC states that the proposed requirements in the NOPR would be complicated to implement for transmission owners that currently do not use AARs, and the implementation timeline would exceed one year since it would require coordination with the transmission management system, development of internal transmission line ratings software or a software purchase from a vendor, and analysis of how AARs will affect ITC's internal transmission line ratings database.[848] The proposed one-year implementation timelines suggest that ITC would need to first develop a costly and error-prone manual process as a short-term solution before developing a more permanent automated process.[849] ITC states that additional time should be built into the Commission's proposed timeline so that initial implementation issues can be identified and corrected.[850] Similarly, NYTOs argue that the one-year compliance timeline for AARs is overly ambitious and could have adverse effects, be costly, and potentially impossible.[851]

355. Other transmission owners voicing concern with the proposed schedule include WAPA, LADWP, and BPA. WAPA notes that it is concerned about the proposed timeline, given its expansive geographic area and transmission system of over 17,000 line miles, and its other statutory duties it must meet to operate its system reliably.[852] LADWP recommends an implementation period of no less than three years for congested transmission lines, noting that the proposed AAR requirements will necessitate extensive re-negotiations of long-term reservation rights and arguing that the AAR implementation timeline is not sufficient to address challenges associated with calculating hourly ATC based on AARs, including development of additional reliability tools and ongoing maintenance of these tools by additional skilled employees.[853] Similarly, BPA asserts that the proposed implementation period is too short because it fails to account for the different transmission provider service territory sizes and for the complexity of AAR implementation.[854]

356. However, according to OMS, the deadlines seem to be reasonable and necessary. OMS states that: MISO Transmission Owners are already working on implementing AARs; since 2016, MISO has had an Integrated Roadmap item called ''Application of Forecasted and Real-time Ambient Adjusted Ratings'' ranked as a high priority in MISO's 2021 Integrated Roadmap Work Plan; and, because MISO Transmission Owners have begun developing a framework to identify candidate AAR facilities based on historical congestion, they should have already begun phase one compliance.[855] Industrial Customer Organizations similarly state that transmission owners should begin AAR implementation now and that, without strict deadlines, AAR implementation before 2022 is unlikely.[856]

357. RTOs/ISOs generally request additional implementation time.[857] CAISO claims that the compliance schedule set forth in the NOPR is neither realistic nor achievable because the proposal for hourly updates to transmission line ratings will require additional market design changes and significant technology enhancements. For the implementation schedule, CAISO requests an additional 18 months from the submission of a compliance filing, explaining that implementation will require technology

1–2; APS Comments at 10; WFEC Comments at 1; Southern Company Comments at 6–7; ITC Comments at 5; LADWP Comments at 8–9.

[834] PacifiCorp Comments at 2–3; PG&E Comments at 6–8.

[835] NYTOs Comments at 1; WAPA Comments at 6; BPA Comments at 6.

[836] OMS Comments at 9; Potomac Economics Comments at 19–20.

[837] Industrial Customer Organizations Comments at 22.

[838] MISO Transmission Owners Comments at 22.

[839] *Id.*

[840] EEI Comments at 18.

[841] Southern Company Comments at 3–4; SCE Comments at 2.

[842] Southern Company Comments at 3–4.

[843] SCE Comments at 2.

[844] PacifiCorp Comments at 3–4.

[845] APS Comments at 6.

[846] NRECA/LPPC Comments at 28–29.

[847] PG&E Comments at 6–7.

[848] ITC Comments at 6.

[849] *Id.* at 6–7.

[850] *Id.* at 7.

[851] NYTOs Comments at 1.

[852] WAPA Comments at 6.

[853] LADWP Comments at 8–9.

[854] BPA Comments at 6.

[855] OMS Comments at 9.

[856] Industrial Customer Organizations Comments at 22.

[857] CAISO Comments at 2; ISO–NE Comments at 8; SPP Comments at 10; MISO Comments at 30–32; NYISO Comments at 16–18.

enhancements necessary to automate the submission and use of hourly adjusted transmission line ratings.[858] SPP contends that 60 days would be insufficient time for SPP to complete its stakeholder process to review any proposed tariff language and notes that, depending on the changes, the process would take at least three months. For implementation, SPP requests an additional two years from the submission of a compliance filing.[859] ISO–NE explains that it will need to upgrade its systems to accept hourly transmission line ratings, and that it does not believe one year would be enough time to do so, but does not propose a timeline.[860] Additionally, ISO–NE asks for sufficient time to analyze how AARs would impact the emergency ratings currently employed and flexibility in implementation timing, and states that an update to the overall rating methodology to include AARs may also necessitate the need for new emergency ratings based on those AARs.[861] MISO states that it would be able to implement the NOPR proposal in the real-time market in a year, but states that it would need until mid-2023 and the end of 2024 to implement the NOPR proposal in the day-ahead market and Intra-day and Foreword Reliability Assessment Commitment respectively.[862] NYISO requests flexibility for each RTO/ISO to develop its own implementation schedule,[863] arguing that the AAR schedule proposed is not enough time to develop the significant changes to software and rules needed,[864] and stating that it could incur significant risk and expense if it is required to comply within the proposed one to two years.[865] PJM, however, states that, while the NOPR proposal will likely require some additional system changes and data validation to comply, it believes the time proposed would be sufficient.[866]

358. Potomac Economics states that clarification may be needed as to whether the requirements for automation are on the transmission line rating submission process and use of AARs or the entire transmission line rating process. Potomac Economics states that requiring full automation may delay implementation and may not be appropriate for all transmission owners.[867]

359. Finally, PJM requests clarity that public utilities are able to demonstrate compliance via the independent entity variation standard, regional reliability standard, or demonstrate that their existing rules are consistent with or superior to the reforms adopted by the Commission.[868]

3. Commission Determination

360. Upon consideration of the comments received, we modify the compliance deadline proposed in the NOPR. Instead of 60 days, we require each transmission provider to submit a compliance filing within 120 days of the effective date of this final rule. We clarify that this compliance deadline is for transmission providers to revise their OATTs to incorporate *pro forma* OATT Attachment M. We agree with EEI's compliance recommendation [869] and find that 120 days will be sufficient to allow for a robust stakeholder evaluation and development of revised tariff language to comply with the requirements adopted in this final rule.

361. In addition, we modify the proposed implementation schedule. Instead of the proposed one-year/two-year staggered implementation timeline based on priority, we require that all requirements adopted herein be implemented no later than three years from the compliance filing due date. Three years is consistent with the implementation schedule most commonly suggested by transmission owners for AAR implementation on priority transmission lines.[870] We find that three years should be sufficient time for transmission owners and transmission providers to implement changes to their processes and systems to comply with the requirements adopted in this final rule.

362. In response to comments about automation from Potomac Economics, we clarify that while we are not adopting a specific automation requirement, we nonetheless believe it is likely that all or much of AAR calculation processes will be automated. However, nothing in this final rule prevents an individual transmission provider from implementing certain portions of the *pro forma* OATT Attachment M requirements manually, should it prefer manual implementation and can satisfy the requirements of this final rule.

363. Finally, some public utility transmission providers may have provisions in their existing *pro forma* OATTs or other document(s) subject to the Commission's jurisdiction that the Commission has deemed to be consistent with or superior to the *pro forma* OATT. Where these provisions would be modified by this final rule, transmission providers must either comply with the requirements adopted in this final rule or demonstrate that these previously approved variations continue to be consistent with or superior to the *pro forma* OATT, as modified by this final rule.[871]

V. Information Collection Statement

364. The information collection (IC) requirements contained in this final rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[872] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[873] Respondents subject to the filing requirements of this final rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

365. This final rule, pursuant to section 206 of the FPA, reforms the *pro forma* OATT and the Commission's regulations to improve the accuracy and transparency of electric transmission line ratings used by transmission providers. These provisions affect the following collections of information: FERC–516H, Pro Forma Open Access Transmission Tariff (Control No. 1902–0297); and FERC–725A, Mandatory Reliability Standards for the Bulk-Power System (Control No. 1902–0244).

366. In the NOPR, the Commission solicited comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

367. Summary of the Collection of Information in the Final Rule:

FERC 516H: This final rule amends 18 CFR 35.28(c)(5) to require any public

[858] CAISO Comments at 2.

[859] SPP Comments at 10.

[860] ISO–NE Comments at 8.

[861] *Id.* at 11.

[862] MISO Comments at 30–32.

[863] NYISO Comments at 16.

[864] *Id.* at 18.

[865] *Id.* at 19.

[866] PJM Comments at 8.

[867] Potomac Economics Comments at 19.

[868] PJM Comments at 15.

[869] EEI Comments at 19.

[870] *Id.* at 18; NRECA/LPPC Comments at 28–29; MISO Transmission Owners Comments at 22–23; SCE Comments at 2; SDG&E Comments at 1–2; APS Comments at 10; WFEC Comments at 1; Southern Company Comments at 6–7; ITC Comments at 5; LADWP Comments at 8–9.

[871] *See* 18 CFR 35.28(c)(1)(vi).

[872] 44 U.S.C. 3507(d).

[873] 5 CFR 1320.11 (2021).

utility that owns transmission facilities that are not under the public utility's control to, consistent with the *pro forma* OATT required by 18 CFR 35.28(c)(1), share with the public utility that controls such facilities (and its Market Monitoring Unit(s), if applicable):

(i) Transmission line ratings for each period for which transmission line ratings are calculated for such facilities (with updated ratings shared each time ratings are calculated); and

(ii) Written transmission line rating methodologies used to calculate the transmission line ratings for such facilities provided under subparagraph (i), above.

Section 35.28(g)(13) of this final rule requires each RTO and ISO to establish and maintain systems and procedures necessary to allow any public utility whose transmission facilities are under the independent control of the ISO or RTO to electronically update transmission line ratings for such facilities (for each period for which transmission line ratings are calculated) at least hourly, with such data submitted by those public utility transmission owners directly into the ISO's or RTO's Energy Management System through Supervisory Control and Data Acquisition or related systems.

FERC–725A: Reliability Standard FAC–008–5 is not being revised in this proceeding. However, as shown in the burden table below, the requirements of this final rule under section 206 of the FPA affect the burden for Requirements 2, 3, and 6 in Reliability Standard FAC–008–5.

368. *Title:* Pro Forma Open Access Transmission Tariff (FERC–516H) and Mandatory Reliability Standards for the Bulk-Power System (FERC–725A).

369. *Action:* Revision of collections of information in accordance with Docket No. RM20–16–000.

370. *OMB Control Nos.:* 1902–0297 (FERC–516H) and 1902–0244 (FERC–725A).

371. *Respondents:* Transmission owners, transmission service providers, generator owners, and RTOs/ISOs.

372. *Frequency of Information Collection:* One time and annually.

373. *Necessity of Information:* The reforms to the *pro forma* OATT and the Commission's regulations will improve the accuracy and transparency of electric transmission line ratings used by transmission providers.

374. *Internal Review:* The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

375. Our estimates are based on the NERC Compliance Registry as of September 3, 2020, which indicates that 78 transmission service providers,[874] 797 generator owners,[875] and 289 transmission owners are registered within the United States and are subject to this rulemaking.[876] There are also six RTOs/ISOs in the United States subject to this rulemaking.

376. *Public Reporting Burden:* The burden and cost estimates below are based on the need for applicable entities to revise documentation, already required by the *pro forma* OATT and the Commission's regulations as well as Reliability Standard FAC–008–5, Facility Ratings.[877]

377. The Commission estimates that the final rule will affect the burden[878] and cost of FERC–516H and FERC–725A as follows:

CHANGES IN FINAL RULE IN DOCKET NO. RM20–16–000

A. Area of modification	B. Number of respondents	C. Annual estimated number of responses per respondent	D. Annual estimated number of responses (column B × column C)	E. Average burden hours & cost[879] per response	F. Total estimated burden hours & total estimated cost (column D × column E)
FERC–516H, Pro Forma Open Access Transmission Tariff (Control No. 1902–0297)					
For point-to-point transmission service requests within ten days, use AARs in determining ATC and TTC. (One-Time Burden in Year 1).	129 (TOs[880] not in RTOs/ISOs[881]).	1	129	1,440 hrs; $120,485	185,760 hrs; $15,542,539.
Where network transmission service is provided, use hourly AARs to determine curtailment or redispatch of network transmission service. (One-Time Burden in Year 1).	160 (to account for those TOs in RTOs/ISOs that are not included in the line above).	1	160	1,440 hrs; $120,485	230,400 hrs; $19,277,568.
Transmission Providers to implement uniquely determined emergency ratings (One-Time Burden in Year 1).	160 (to account for those TOs in RTOs/ISOs that are not included in the line above).	1	160	360 hrs; $30,121	57,600 hrs; $4,819,392.
Implement software and systems to communicate the required transmission line ratings with relevant parties. (One-Time Burden in Year 1).	78 (TSPs[882])	1	78	352 hrs; $29,452	27,456 hrs; $2,297,243.

[874] The transmission service provider (TSP) function is a NERC registration function which is similar to the transmission provider that is referenced in the *pro forma* OATT. The TSP function is being used as a proxy to estimate the number of transmission providers that are impacted by this rulemaking.

[875] Of the 797 generator owners listed in the September 3, 2020 NERC Compliance Registry, the Commission estimates that only 10% of all NERC registered generator owners own facilities between the step-up transformer and the point of interconnection. For this reason, the Commission estimates that only 80 generator owners are affected.

[876] The number of entities listed from the NERC Compliance Registry reflects the omission of the Texas RE registered entities.

[877] The burden associated with Reliability Standard FAC–008–5, approved by the Commission under section 215 of the FPA, is included in the OMB-approved inventory for FERC–725A. Reliability Standard FAC–008–5 is not being revised in this proceeding; however, the requirements of this final rule under section 206 of the FPA affect the burden for three requirements in Reliability Standard FAC–008–5.

[878] "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR 1320.3.

CHANGES IN FINAL RULE IN DOCKET NO. RM20–16–000—Continued

A. Area of modification	B. Number of respondents	C. Annual estimated number of responses per respondent	D. Annual estimated number of responses (column B × column C)	E. Average burden hours & cost [879] per response	F. Total estimated burden hours & total estimated cost (column D × column E)
RTOs/ISOs implement software with the ability to accommodate AARs in both the day-ahead and real-time markets on an hourly basis. (One-Time Burden in Year 1).	6 (RTOs/ISOs)	1	6	9,000 hrs; $753,030	54,000 hrs; $4,518,180.
RTOs/ISOs establish the systems and procedures necessary to allow transmission owners to update line ratings on an hourly basis directly into an EMS. (One-Time Burden in Year 1).	6 (RTOs/ISOs)	1	6	1,056 hrs; $88,356	6,336 hrs; $530,133.
Transmission owners update forecasts and ratings, and share transmission line ratings and facility ratings methodologies w/transmission providers and, if applicable, RTOs/ISOs & market monitors (Year 1 and Ongoing).	289 (TOs)	1	289	176 hrs; $14,726	50,864 hrs; $4,255,791.
Compliance Filings (One-Time Burden in Year 1).	295 (TOs and (RTOs/ISOs).	1	295	160 hrs; $13,387	47,200 hrs; $3,949,224.
Net Subtotal for FERC–516H (Year 1).			373	13,984 hrs; $1,170,041	429,216 hrs; $50,671,891.
Net Subtotal for FERC–516H (Ongoing).			289	176 hrs; $14,726	50,864 hrs; $4,255,791.
FERC–725A, Mandatory Reliability Standards for the Bulk-Power System—Reliability Standard FAC–008–5					
Review and update facility ratings methodology, Requirements R2 and R3. (One-Time Burden in Year 1).	369 (TOs & GOs) [883]	1	369	40 hrs; $3,347	14,760 hrs; $1,234,969.
Determine facility ratings consistent with methodology, Requirement R6. (Burden in Year 1 and Ongoing).	369 (TOs & GOs)	1	369	8 hrs; $669	2,952 hrs; $246,994.
Net Subtotal for FERC–725A (Year 1).			369	48 hrs; $4,016	17,712 hrs; $1,481,963.
Net Subtotal for FERC–725A (Ongoing).			369	8 hrs; $669	2,952 hrs; $246,994.

378. The Commission noted in the NOPR that, for purposes of estimating burden in the NOPR, the Commission conservatively estimated these values based on the maximum number of entities and burden. The Commission noted that some entities may, for example, already use AARs in their existing operations, in which case the actual burden associated with specific reforms associated with the use of AARs would be lower than the estimate. The Commission added that, on the other hand, changing approaches to facility ratings may require extra testing and training for some entities to ensure reliable operations and gain familiarity with the approach. In the NOPR, the Commission explained that it estimated that the majority of the additional burden associated with the NOPR would occur in the first year, and that, once established, the ongoing burden would closely approach the existing burden of operating the transmission system. The Commission sought comment on the estimates in the table provided in the NOPR and the assumptions described in the NOPR.

379. We have revised the table above to reflect the additional burden associated with the additional requirements issued in this final rule related to emergency ratings and daytime and nighttime ratings.

380. We have also revised the table based on comments provided by MISO. MISO states that it estimates costs of approximately $200,000 to implement AARs for current hour transmission service, and costs to implement forecasted AARs in the forward markets and for transmission service, such as in

[879] The hourly cost (for salary plus benefits) uses the figures from the Bureau of Labor Statistics (BLS) for three positions involved in the reporting and recordkeeping requirements. These figures include salary (based on BLS data for May 2019, *http://bls.gov/oes/current/naics2_22.htm*) and benefits (based on BLS data for December 2019; issued March 19, 2020, *http://www.bls.gov/news.release/ecec.nr0.htm*) and are Manager (Code 11–0000 $97.15/hour), Electrical Engineer (Code 17–2071 $70.19/hour), and File Clerk (Code 43–4071 $34.79/hour). The hourly cost for the reporting requirements ($83.67) is an average of the cost of a manager and engineer. The hourly cost for recordkeeping requirements uses the cost of a file clerk.

[880] Transmission Owners. While the AAR reforms in the final rule apply to transmission providers, the Commission computes an implementation burden based on the number of transmission owners because transmission owners typically calculate transmission line ratings and are therefore likely to be the entities that update computations to determine the effect of changing ambient air temperatures on transmission line ratings.

[881] Regional Transmission Organizations/Independent System Operators.

[882] Transmission Service Providers.

[883] This number reflects 289 transmission owners and 10% of the 797 generator owners (GOs) estimated to own facilities between the step-up transformer and the point of interconnection.

the day-ahead market, between $500,000 and $750,000.[884] The Commission has conservatively applied this estimate to all of the RTOs/ISOs. The Commission notes, however, that this is a conservative maximum estimate and that some RTOs/ISOs might have pre-existing plans to upgrade software in the coming years, which may implement many of the same functionalities necessitated by this final rule that are captured in these RTO/ISO cost estimates.

381. In this final rule, besides the noted revisions, the Commission used the numbers provided in the NOPR.

382. Interested persons may obtain information on the reporting requirements by contacting Ellen Brown, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 via email (*DataClearance@ferc.gov*) or telephone ((202) 502–8663).

VI. Environmental Analysis

383. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[885] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classification, and services.[886]

VII. Regulatory Flexibility Act

384. The Regulatory Flexibility Act of 1980 [887] generally requires a description and analysis of proposed and final rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold for what constitutes a small business. The small business size standards are provided in 13 CFR 121.201 (2021). Under SBA's size standards,[888] RTOs/ISOs, planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 500 employees (including the entity and its associates).[889]

385. The six RTOs/ISOs (SPP, MISO, PJM, ISO–NE, NYISO, and CAISO) each employ more than 500 employees and are not considered small.

386. We estimate that 337 transmission owners and six planning authorities are also affected by this final rule. Using the list of transmission owners from the NERC Registry (dated September 3, 2020), we estimate that approximately 68% of those entities are small entities.

387. We estimate that 80 generator owners own facilities between the step-up transformer and the point of interconnection. We estimate again that 68% of these are small entities.

388. We estimate that 78 transmission service providers are affected by this final rule. We estimate again that 68% of these are small entities.

389. We estimate additional one-time costs associated with this final rule (as shown in the table above) of:

390. $854,773 for each RTO/ISO (FERC–516H).

391. $178,719 for each transmission owner (FERC–516H).

392. $3,347 for each transmission owner (FERC–725A).

393. $13,387 for each affected generator owner (FERC–516H).

394. $3,347 for each generator owner (FERC–725A).

395. $29,452 for each transmission service provider (FERC–516H).

396. Therefore, the estimated additional one-time cost per entity ranges from $16,734 to $854,773.

397. We estimate that the majority of the additional burden associated with this final rule occurs in the first year (as shown in the table above), and that, once established, the ongoing burden will closely approach the existing burden of operating the transmission system.

398. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors." [890] We do not consider the estimated cost to be a significant economic impact. As a result, we certify that this final rule will not have a significant economic impact on a substantial number of small entities.

VIII. Document Availability

399. 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 (*http://www.ferc.gov*). At this time, the Commission has suspended access to the Commission's Public Reference Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

400. From FERC'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.

401. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC 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.*

IX. Effective Date and Congressional Notification

402. This final rule is effective 60 days from the later of the date Congress receives the agency notice or the date the rule is published in the **Federal Register**. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 35

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

[884] MISO Comments at 32.

[885] *Reguls. Implementing the Nat'l Envt'l Pol'y Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[886] 18 CFR 380.4(a)(15) (2021).

[887] 5 U.S.C. 601–612.

[888] 13 CFR 121.201.

[889] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. The Small Business Administrations' regulations at 13 CFR 121.201 define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 500 employees. *See* 5 U.S.C. 601(3) (citing to Section 3 of the Small Business Act, 15 U.S.C. 632).

[890] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* at 18 (May 2012), *https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.*

By the Commission. Commissioner Danly is concurring with a separate statement attached.

Commissioner Phillips is not participating.

Issued: December 16, 2021.

Debbie-Anne A. Reese,

Deputy Secretary.

In consideration of the foregoing, the Commission amends part 35, chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. Amend § 35.28 by adding paragraphs (b)(12) through (16), (c)(5), and (g)(13) to read as follows:

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(b) * * *

(12) *Ambient-adjusted rating* means a transmission line rating that applies to a time period of not greater than one hour; reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; 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 is calculated at least each hour, if not more frequently.

(13) *Emergency rating* means 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.

(14) *Dynamic line rating* means 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.

(15) *Energy Management System* (EMS) means a computer control system used by electric utility dispatchers to monitor the real-time performance of the various elements of an electric system and to dispatch, schedule, and/or control generation and transmission facilities.

(16) *Supervisory Control and Data Acquisition* (SCADA) means a computer system that allows an electric system operator to remotely monitor and control elements of an electric system.

(c) * * *

(5) Any public utility that owns transmission facilities that are not under the public utility's control must, consistent with the pro forma tariff required by paragraph (c)(1) of this section, share with the public utility that controls such facilities (and its Market Monitoring Unit(s), if applicable):

(i) Transmission line ratings for each period for which transmission line ratings are calculated for such facilities (with updated ratings shared each time ratings are calculated); and

(ii) Written transmission line rating methodologies used to calculate the transmission line ratings for such facilities provided under subparagraph (i).

* * * * *

(g) * * *

(13) *Transmission line ratings.* (i) Each Commission-approved independent system operator or regional transmission organization must establish and maintain systems and procedures necessary to allow any public utility whose transmission facilities are under the independent control of the independent system operator or regional transmission organization to electronically update transmission line ratings for such facilities (for each period for which transmission line ratings are calculated) at least hourly, with such data submitted by those public utility transmission owners directly into the independent system operator's or regional transmission organization's EMS through SCADA or related systems.

(ii) [Reserved]

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

Appendix A: Abbreviated Names of Commenters

The following table contains the abbreviated names of the commenters that are used in this final rule.

Short name/acronym	Commenter
AEP	American Electric Power Company, Inc.
ACORE	The American Council on Renewable Energy.
ACPA/SEIA	American Clean Power Association (ACPA) and the Solar Energy Industries Association (SEIA).
APS	Arizona Public Service Company.
BPA	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
CAISO DMM	California Independent System Operator Corporation Department of Market Monitoring.
CEA	Canadian Electricity Association.
Certain TDU	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	Clean Energy Parties consist of the Natural Resources Defense Council, Sustainable FERC Project, Conservation Law Foundation, Sierra Club, Western Resource Advocates, Western Grid Group, Clean Grid Alliance, NW Energy Coalition, and Southern Environmental Law Center.
DC Energy	DC Energy, LLC.
Dominion	Dominion Energy Services, Inc.
Duke Energy	Duke Energy Corporation.
EDFR	EDF Renewables, Inc.
EEI	Edison Electric Institute.
ENEL	ENEL North America.
Entergy	Entergy Services, LLC.
EPRI	Electric Power Research Institute.
EPSA	Electric Power Supply Association.
Eversource	Eversource Energy Service Company.
Exelon	Exelon Corporation.
IID	Imperial Irrigation District.

Short name/acronym	Commenter
Indicated PJM Transmission Owners	Indicated PJM Transmission Owners consist of: American Electric Power Service Corporation on behalf of its affiliates, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc., and AEP West Virginia Transmission Company, Inc. (collectively "AEP"); Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia; Duke Energy Corporation on behalf of its affiliates Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., and Duke Energy Business Services LLC; Exelon Corporation; FirstEnergy Service Company, on behalf of its affiliates American Transmission Systems, Incorporated, Jersey Central Power & Light Company, MidAtlantic Interstate Transmission LLC, West Penn Power Company, The Potomac Edison Company, Monongahela Power Company, and Trans-Allegheny Interstate Line Company; PPL Electric Utilities Corporation; and Rockland Electric Company.
Industrial Customer Organizations	Industrial Customer Organizations consists of: American Forest & Paper Association (AF&PA), Coalition of MISO Transmission Customers (CMTC), Electricity Consumers Resource Council (ELCON), Industrial Energy Consumers of America (IECA), and the PJM Industrial Customer Coalition (PJMICC).
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.
MISO Transmission Owners	MISO Transmission Owners consist of: Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri, Ameren Illinois Company d/b/a Ameren Illinois, and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; Central Minnesota Municipal Power Agency; City Water, Light & Power (Springfield, IL); Cleco Power LLC; Cooperative Energy; Dairyland Power Cooperative; Duke Energy Business Services, LLC for Duke Energy Indiana, LLC; East Texas Electric Cooperative; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; International Transmission Company d/b/a ITC Transmission; ITC Midwest LLC; Lafayette Utilities System; Michigan Electric Transmission Company, LLC; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Missouri River Energy Services; Montana-Dakota Utilities Co.; Northern Indiana Public Service Company LLC; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Power Company; Prairie Power Inc.; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
NERC	North American Electric Reliability Corporation.
New England State Agencies	New England State Agencies consist of: Connecticut Attorney General William Tong; Massachusetts Attorney General Maura Healey; the Connecticut Department of Energy and Environmental Protection; the Connecticut Office of Consumer Counsel; the Maine Office of the Public Advocate; the New Hampshire Consumer Advocate; Peter F. Neronha, Rhode Island Attorney General; and Thomas J. Donovan, Jr., Attorney General of Vermont.
NRECA/LPPC	National Rural Electric Cooperative Association (NRECA) and the Large Public Power Council (LPPC).
NYISO	New York Independent System Operator, Inc.
NYTOs	The New York Transmission Owners consist of: Central Hudson Gas & Electric Corporation (Central Hudson); Consolidated Edison Company of New York, Inc. (Consolidated Edison); Niagara Mohawk Power Corporation d/b/a National Grid (National Grid); New York Power Authority (NYPA); New York State Electric & Gas Corporation (NYSEG); Orange and Rockland Utilities, Inc. (O&R); Long Island Power Authority (LIPA); and Rochester Gas and Electric Corporation (RG&E).
Ohio FEA	Public Utilities Commission of Ohio's Office of the Ohio Federal Energy Advocate.
OMS	Organization of MISO States.
PacifiCorp	PacifiCorp.
PG&E	Pacific Gas and Electric Company.
PJM	PJM Interconnection, L.L.C.
Potomac Economics	Potomac Economics, LTD.
Prysmian	The Prysmian Group.
R Street Institute	R Street Institute.
SCE	Southern California Edison Company.
SDG&E	San Diego Gas & Electric Company.
Southern Company	Solar Energy Industries Association.
SPP	Southern Company Services, Inc.
SPP MMU	Southwest Power Pool, Inc.
Sunflower	Sunflower Electric Power Corporation.
Tangibl	Tangibl Group, Inc.
TAPS	Transmission Access Policy Study Group.
UDPU	Utah Division of Public Utilities.
Vistra	Vistra Corp.
WAPA	Western Area Power Administration.
WATT	Working for Advanced Transmission Technologies.
WFEC	Western Farmers Electric Cooperative.

Appendix B: Pro Forma Open Access Transmission Tariff

ATTACHMENT M

Transmission Line Ratings

General

The Transmission Provider will implement Transmission Line Ratings on the transmission lines over which it provides Transmission Service, as provided below.

Definitions

The following definitions apply for purposes of this Attachment:

(1) ''Transmission Line Rating'' means the maximum transfer capability of a transmission line, computed in accordance with a written Transmission Line Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the Transmission System (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.

(2) ''Ambient-Adjusted Rating'' (AAR) means 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.

(d) Is calculated at least each hour, if not more frequently.

(3) ''Seasonal Line Rating'' means a Transmission Line Rating that:

(a) Applies to a specified season, where seasons are defined by the Transmission Provider to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.

(b) Reflects an up-to-date forecast of ambient air temperature across the relevant season over which the rating applies.

(c) Is calculated annually, if not more frequently, for each season in the future for which Transmission Service can be requested.

(4) ''Near-Term Transmission Service'' means Transmission Service which ends not more than 10 days after the Transmission Service request date. When the description of obligations below refers to either a request for information about the availability of potential Transmission Service (including, but not limited to, a request for ATC), or to the posting of ATC or other information related to potential service, the date that the information is requested or posted will serve as the Transmission Service request date. ''Near-Term Transmission Service'' includes any Point-To-Point Transmission Service, Network Resource designations, or secondary service where the start and end date of the designation or request is within the next 10 days.

(5) ''Emergency Rating'' means 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.

System Reliability

If the Transmission Provider reasonably determines, consistent with Good Utility Practice, that the temporary use of a Transmission Line Rating different than would otherwise be required by this Attachment is necessary to ensure the safety and reliability of the Transmission System, then the Transmission Provider may use such an alternate rating. The Transmission Provider must document in its database of Transmission Line Ratings and Transmission Line Rating methodologies on OASIS or another password-protected website, as required by this Attachment, the use of an alternate Transmission Line Rating under this paragraph, including the nature of and basis for the alternate rating, the date and time that the alternate rating was initiated, and (if applicable) the date and time that the alternate rating was withdrawn and the standard rating became effective again.

Obligations of Transmission Provider

The Transmission Provider will have the following obligations.

The Transmission Provider must use AARs as the relevant Transmission Line Ratings when performing any of the following functions: (1) Evaluating requests for Near-Term Transmission Service; (2) responding to requests for information on the availability of potential Near-Term Transmission Service (including requests for ATC or other information related to potential service); or (3) posting ATC or other information related to Near-Term Transmission Service to the Transmission Provider's OASIS site or another password-protected website.

The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining whether to curtail (under section 13.6) Firm Point-To-Point Transmission Service or when determining whether to curtail and/or interrupt (under section 14.7) Non-Firm Point-To-Point Transmission Service if such curtailment and/or interruption is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination. For determining whether to curtail or interrupt Point-To-Point Transmission Service in other situations, the Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings.

The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining whether to curtail (under section 33) or redispatch (under sections 30.5 and/or 33) Network Integration Transmission Service or secondary service if such curtailment or redispatch is both necessary because of issues related to flow limits on transmission lines and anticipated to occur (start and end) within 10 days of such determination. For determining the necessity of curtailment or redispatch of Network Integration Transmission Service or secondary service in other situations, the Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings.

The Transmission Provider must use Seasonal Line Ratings as the relevant Transmission Line Ratings when evaluating requests for and whether to curtail, interrupt, or redispatch any Transmission Service not otherwise covered above in this section (including, but not limited to, requests for non-Near-Term Transmission Service or requests to designate or change the designation of Network Resources or Network Load), when developing any ATC or other information posted or provided to potential customers related to such services. The Transmission Provider must use Seasonal Line Ratings as a recourse rating in the event that an AAR otherwise required to be used under this Attachment is unavailable.

The Transmission Provider must use uniquely determined Emergency Ratings for contingency analysis in the operations horizon and in post-contingency simulations of constraints. Such uniquely determined Emergency Ratings must also include separate AAR calculations for each Emergency Rating duration used.

In developing forecasts of ambient air temperature for AARs and Seasonal Line Ratings, the Transmission Provider must develop such forecasts consistent with Good Utility Practice and on a non-discriminatory basis.

Postings to OASIS or another password-protected website: The Transmission Provider must maintain on the password-protected section of its OASIS page or on another password-protected website a database of Transmission Line Ratings and Transmission Line Rating methodologies. The database must include a full record of all Transmission Line Ratings, both as used in real-time operations, and as used for all future periods for which Transmission Service is offered. Any postings of temporary alternate Transmission Line Ratings or exceptions used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. The database must include records of which Transmission Line Ratings and Transmission Line Rating methodologies were in effect at which times over at least the previous five years, including records of which temporary alternate Transmission Line Ratings or exceptions were in effect at which times during the previous five years. Each record in the database must indicate which transmission line the record applies to, and the date and time the record was entered into the database. The database must be maintained such that users can view, download, and query data in standard formats, using standard protocols.

Sharing with Transmission Providers: The Transmission Provider must share, upon request by any Transmission Provider and in a timely manner, the following information:

(1) Transmission Line Ratings for each period for which Transmission Line Ratings

are calculated, with updated ratings shared each time Transmission Line Ratings are calculated, and

(2) Written Transmission Line Rating methodologies used to calculate the Transmission Line Ratings in (1) above.

Exceptions: Where the Transmission Provider determines, consistent with Good Utility Practice, that the Transmission Line Rating of a transmission line is not affected by ambient air temperature or solar heating, the Transmission Provider may use a Transmission Line Rating for that transmission line that is not an AAR or Seasonal Line Rating. Examples of such a transmission line may include (but are not limited to): (1) A transmission line for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature or solar heating; or (2) a transmission line whose transfer capability is limited by a Transmission System limit (such as a system voltage or stability limit) which is not dependent on ambient air temperature or solar heating. The Transmission Provider must document in its database of Transmission Line Ratings and Transmission Line Rating methodologies on OASIS or another password-protected website any exceptions to the requirements contained in this Attachment initiated under this paragraph, including the nature of and basis for each exception, the date(s) and time(s) that the exception was initiated, and (if applicable) the date(s) and time(s) that each exception was withdrawn and the standard rating became effective again. If the technical basis for an exception under this paragraph changes, then the Transmission Provider must update the relevant Transmission Line Rating(s) in a timely manner. The Transmission Provider must reevaluate any exceptions taken under this paragraph at least every five years.

FEDERAL ENERGY REGULATORY COMMISSION

Managing Transmission Line Ratings
Docket No. RM20–16–000

(Issued December 16, 2021)

DANLY, Commissioner, *concurring:*

1. I concur with the issuance of this final rule because I agree that the record in this proceeding supports a finding that current transmission rates are unjust and unreasonable because line rating information is often inaccurate.[1] The rates customers pay to support transmission are distorted because the ratings that purport to represent the true operating characteristics of the transmission system are distorted. The voluminous record evidence in this proceeding is sufficient to support a Federal Power Act section 206 action to remedy unjust and unreasonable rates.[2] The record also is sufficient to support the replacement rates we order in this rule.

2. Of course, we cannot act pursuant to section 206 without substantial record evidence that the existing rate is unjust and unreasonable and further record support for a replacement rate. We cannot impose a requirement for dynamic line ratings, for example, because we do not have the record support to do so at this time.[3] Action cannot be taken under section 206 merely because a potential reform is a good idea or because a contemplated policy might yield greater efficiencies.

3. Here, I am persuaded that we have sufficient record evidence to require ambient-adjusted ratings (AAR) on all transmission lines because the record shows the existing paradigm significantly distorts efficient use of the transmission system.[4] In addition, AAR is a just and reasonable replacement rate because the record evidence shows the additional costs are incremental and will provide significant benefits.

4. In this case, the requirements of both steps of section 206 have been satisfied. As a Commission, we must ensure that every action taken under section 206 fully meets these burdens and I will apply the same rigorous analysis to every future section 206 proposal to improve the transmission system.

For these reasons, I respectfully concur.

James P. Danly,

Commissioner.

[1] *Managing Transmission Line Ratings,* 177 FERC ¶ 61,179 at P 29 (2021).

[2] 16 U.S.C. 824e.

[3] *See Managing Transmission Line Ratings,* 177 FERC ¶ 61,179 at P 36 (declining to require dynamic line ratings).

[4] *Id.* at P 83.

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