DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM20–16–000]

Managing Transmission Line Ratings

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to reform 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 transmission line ratings. Specifically, the proposal would require: Transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in RTOs/ISOs, with their respective market monitor(s).

DATES: Comments are due March 22, 2021.

ADDRESSES: Comments, identified by docket number RM20–16, may be filed electronically at *http://www.ferc.gov* in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. The Comment Procedures Section of this document contains more detailed filing procedures.

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SUPPLEMENTARY INFORMATION:

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I. Introduction

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes, pursuant to section 206 of the Federal Power Act (FPA),[1] to reform the *pro forma* Open Access Transmission Tariff (OATT) and the Commission's regulations to improve the accuracy and transparency of transmission line ratings used by transmission providers. Transmission line ratings represent the maximum transfer capability of each transmission line. As explained below, 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. Inaccurate transmission line ratings may result in Commission-

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

jurisdictional rates that are unjust and unreasonable.

2. Transmission line ratings often are calculated based on assumptions about ambient conditions that do not accurately reflect the near-term transfer capability of the system.[2] For example, transmission line ratings currently based on seasonal or static assumptions may indicate less transmission system transfer capability than the transmission system can actually provide, leading to restricted flows and increased congestion costs. Alternatively, transmission line ratings currently based on seasonal or static assumptions may overstate the near-term transfer capability of the system, creating potential reliability and safety problems. In either case, the current use of seasonal and static assumptions results in transmission line ratings that do not accurately represent the transfer capability of the transmission system.

3. To address these issues with respect to shorter-term requests for transmission service, we propose two requirements for greater use of ambient-adjusted line ratings (AARs),[3] which are transmission line ratings that incorporate near-term forecasted ambient air temperatures. First, we propose to require that transmission providers use AARs as the basis for evaluation of transmission service requests that will end within ten days of the request. Second, we propose to require that transmission providers use AARs as the basis for determination of the necessity of certain curtailment, interruption, or redispatch of transmission service that is anticipated to occur within those ten days.

4. To address these issues with respect to longer-term requests for transmission service, we propose to require that transmission providers use seasonal line ratings as the basis for evaluation of such requests. We also propose to require that transmission providers use seasonal line ratings as the basis for the determination of the necessity of curtailment, interruption, or redispatch that is anticipated to occur more than ten days in the future.[4]

5. Moreover, in certain situations, use of dynamic line ratings (DLRs) presents opportunities for transmission line ratings that may be more accurate than those established with AARs.[5] DLRs are based not only on forecasted ambient air temperature, but also on other weather conditions such as wind, cloud cover, solar irradiance intensity, precipitation, and/or on transmission line conditions such as tension or sag. One factor that may contribute to the limited deployment of DLRs by transmission owners is that the regional transmission organizations (RTO) and independent system operators (ISO) that operate the transmission system 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. To address this issue, we propose to require RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings on at least an hourly basis.

6. The proposed reforms noted above are intended to improve the accuracy of transmission line ratings used during normal (pre-contingency) operations.[6] We also seek comment on whether to require transmission providers to implement unique emergency ratings [7] that would be used during post-contingency operations.

7. Finally, we propose to require transmission owners to share transmission line ratings and methodologies with their transmission provider(s) and, in regions served by an RTO/ISO, also with the market monitor(s) of that RTO/ISO. We also seek comment on whether transmission line ratings and transmission line rating methodologies should be shared with other transmission providers, upon request.

8. We seek comment on these proposed reforms by 60 days after publication of this NOPR in the **Federal Register**.

II. Background

A. Order Nos. 888 and 889

9. In Order No. 888, the Commission required public utilities to unbundle their generation and transmission services and file open access non-discriminatory transmission tariffs (OATTs) to allow third parties equal access to their transmission system.[8] In Order No. 889, issued at the same time as Order No. 888, the Commission established part 37 of the Commission's regulations that require each public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce to create or participate in an Open Access Same-time Information System (OASIS) that would provide transmission customers the same access to information to enable them to obtain open access non-discriminatory transmission service.[9] Among the new requirements, public utilities were directed to calculate their available transfer capability (ATC) as a way to give potential third party transmission customers information on transmission service availability. In Order No. 888, the Commission used the term ''Available Transmission Capability'' to describe the amount of additional

[2] 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.*

[3] As discussed below, we propose to define an ambient-adjusted line rating, or 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; and (3) is calculated at least each hour, if not more frequently. Proposed 18 CFR 35.28(b)(10).

[4] The use of seasonal transmission 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 detailed later, the Commission proposes changes to seasonal transmission line rating implementation.

[5] As discussed below, the Commission proposes to define a dynamic line rating, or DLR, as a transmission line rating that: (1) Applies to a time period of not greater than one hour; (2) reflects up-to-date forecasts of inputs such as (but not limited to) ambient air temperature, wind, solar irradiance intensity, transmission line tension, or transmission line sag; and (3) is calculated at least each hour, if not more frequently. Proposed 18 CFR 35.28(b)(11).

[6] The NERC Glossary defines ''normal 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 2, 2020), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[7] The NERC Glossary defines ''emergency rating'' as: ''T[t]he rating as defined by the equipment owner that specifies the level of electrical loading or output . . . 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.'' *Id.* For purposes of this NOPR, the phrase ''unique emergency ratings'' describes an emergency rating that is a different value from a facility's normal rating. Typically, the emergency rating would be a higher value than the normal rating unless there is specific constraint that prohibits a higher emergency rating.

[8] *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 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 77 FERC ¶ 61,080), *order on reh'g,* Order No. 888–A, 62 FR 12,274 (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).

[9] *Open Access Same-Time Information System and Standards of Conduct,* Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996) (cross-referenced at 75 FERC ¶ 61,078), *order on reh'g,* Order No. 889–A, FERC Stats & Regs. ¶ 31,049 (cross-referenced at 78 FERC ¶ 61,221), *reh'g denied,* Order No. 889–B, 81 FERC ¶ 61,253 (1997).

capability available in the transmission network to accommodate additional requests for transmission services. The Commission in Order No. 890 adopted the current term ATC in the *pro forma* OATT to be consistent with the term generally accepted throughout the industry.[10] For the purposes of this proceeding, ATC will also refer to available flowgate capability.[11]

10. In Order No. 889, the Commission required that ATC and Total Transfer Capability (TTC) be calculated based on a methodology described in the Transmission Provider's tariff, and that those calculations be based on current industry practices, standards and criteria.[12] The Commission also made further changes to its regulations as part of Order No. 889 to ensure accuracy of the data posted on OASIS.[13] For example, the Commission required that entities that calculate ATC or TTC on constrained posted paths make publicly available the underlying data and methodologies.[14]

11. At the time, no formal methodologies existed to calculate ATC, and the Commission encouraged the industry to develop a consistent transmission line rating methodology.[15] While Order No. 888 required transmission providers to include descriptions of ATC methodologies in their tariffs,[16] Order No. 889 required public utilities to post ATC values and certain related information to their OASIS.[17]

B. Order No. 890

12. In Order No. 890, the Commission addressed and remedied opportunities for undue discrimination under the regulations and the *pro forma* OATT adopted in Order Nos. 888 and 889.[18] Among other things, the Commission found that the lack of ATC consistency and transparency throughout the industry allowed for undue discrimination, with transmission providers able to favor themselves and their affiliates over third parties in allocating ATC.[19] The Commission also stated that ATC inconsistencies made it difficult for parties to detect discrimination.[20] In response to these concerns, the Commission directed public utilities, working through North American Electric Reliability Corporation (NERC) Reliability Standards and North American Energy Standards Board (NAESB) business practices development processes, to produce workable solutions to complex and contentious issues surrounding improving the consistency and transparency of ATC calculations.[21] This included the development of standard ATC calculation methodologies, definitions for the components in the ATC equation, and standards for data inputs, assumptions, and information exchanges to be applied across the industry.[22]

C. ATC-Related Reliability Standards, Business Practices, and Commission Regulations

13. The Commission in Order No. 729,[23] pursuant to section 215 of the FPA,[24] approved six Reliability Standards,[25] subsequently referred to as the ''MOD A Reliability Standards'' by NERC, and stated the Commission believes that these Reliability Standards address the potential for undue discrimination by requiring industry-wide transparency and increased consistency regarding all components of the ATC calculation methodology and certain definitions, data, and modeling assumptions.[26]

14. On July 16, 2020, the Commission issued a NOPR[27] proposing to amend its regulations because of the importance of the ATC calculation and as a result of the proposed retirement of NERC's MOD A standards. The Commission proposed to revise its regulations to establish the general criteria transmission owners must use in calculating ATC.[28] The Commission also proposed to adopt the NAESB wholesale electric quadrant

[10] The NERC Glossary defines ATC as: ''A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability (TTC) less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 2, 2020), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[11] Available flowgate capability is defined in the NERC Glossary as: ''A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as [total flowgate capability] TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 2, 2020), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[12] Order No. 889, FERC Stats. & Regs. ¶ 31,035 at ¶ 31,607.

[13] *Id.* ¶ 31,608.

[14] *See* 18 CFR 37.6 (b)(2)(ii) (stating that, on request, the responsible party must make all data used to calculate ATC, TTC, CBM, and TRM for any constrained posted paths publicly available (including the limiting element(s) and the cause of the limit (*e.g.,* thermal, voltage, stability), as well as load forecast assumptions) in electronic form within one week of the posting.).

[15] Order No. 889, FERC Stats. & Regs. ¶ 31,035 at ¶ 31,607.

[16] The Commission requires ''all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce [t]o file open access non-discriminatory transmission tariffs that contain minimum terms and conditions of non-discriminatory service.'' Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,635. Public utilities also are ''required to make section 206 compliance filings to meet . . . *pro forma* tariff non-price minimum terms and conditions of non-discriminatory transmission. *Id.* at 31,636. The *pro forma* OATT's ''Methodology To Assess Available Transmission Capability'' is proscribed in Attachment C of the Order. *Id.* at 31,930.

[17] Order No. 889, FERC Stats. & Regs. ¶ 31,035 at 31,587.

[18] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 118 FERC ¶ 61,119, *order on reh'g,* Order No. 890–A, 121 FERC ¶ 61,297 (2007), *order on reh'g and clarification,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[19] Order No. 890, 118 FERC ¶ 61,119 at P 83.

[20] *Id.* P 21. In regions with RTOs/ISOs, the RTO/ISO in most cases calculated the ATC for paths within their territory.

[21] *Id.* P 196.

[22] *Id.* P 207.

[23] *Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the Bulk-Power System,* Order No. 729, 129 FERC ¶ 61,155, at P 13 (2009), *order on clarification,* Order No. 729–A, 131 FERC ¶ 61,109, *order on reh'g,* Order No. 729–B, 132 FERC ¶ 61,027 (2010).

[24] 16 U.S.C. 824o.

[25] The Reliability Standards were: MOD–001–1—Available Transmission System Capability; MOD–004–1—Capacity Benefit Margin; MOD–008–1—TRM Calculation Methodology; MOD–028–1—Area Interchange Methodology; MOD–029–1—Rated System Path Methodology; and MOD–030–1—Flowgate Methodology.

[26] Order No. 729, 129 FERC ¶ 61,155 at P 2.

[27] *Standards for Business Practices and Communication Protocols for Public Utilities,* Notice of Proposed Rulemaking, 172 FERC ¶ 61,047, at P 49 (2020).

[28] *Id.* P 50 (proposing new language, shown in italics, for the Commission's regulations governing the calculation of ATC and TTC in 18 CFR 37.6(b)(2)(i)), that calculation methods, availability of information, and requests. Information used to calculate any posting of ATC and TTC must be dated and time-stamped and all calculations shall be performed according to consistently applied methodologies referenced in the Transmission Provider's transmission tariff and shall be based on Commission-approved Reliability Standards, *business practice and electronic communication standards, and related implementation documents,* as well as current industry practices, standards and criteria. *Transmission Providers shall calculate ATC and TTC in coordination with and consistent with capability and usage on neighboring systems, calculate system capability using factors derived from operations and planning data for the time frame for which data are being posted (including anticipated outages), and update ATC and TTC calculations as inputs change. Such calculations shall be conducted in a manner that is transparent, consistent, and not unduly discriminatory or preferential.*)

(WEQ) Business Practice Standards that include commercially relevant requirements from the existing MOD A Reliability Standards as they appeared generally consistent with those criteria.[29] On September 17, 2020, the Commission, in Order No. 873, approved the retirement of 18 Reliability Standard requirements identified by NERC, the Commission-certified Electric Reliability Organization.[30] The Commission also remanded proposed Reliability Standard FAC–008–4 for further consideration by NERC and took no action on the proposed retirement of 56 MOD A Reliability Standard requirements.[31]

D. Reliability Standard FAC–008–3 (Facility Ratings)

15. The requirements of Reliability Standard FAC–008–3 (Facility Ratings) [32] are generally as follows:

• Requirement number 1 (''R1'') requires a generator owner to provide documentation for determining the facility ratings of its generator facility(ies).

• Requirement R2 requires each generator owner to have a documented methodology for determining facility ratings of its equipment connected between the location specified in Requirement R1 and the point of interconnection with the transmission owner.

• Requirement R3 requires each transmission owner to have a documented methodology for determining facility ratings (facility ratings methodology) of its facilities.[33]

• Requirement R6 requires that the generator owner and transmission owner also establish facility ratings for their facilities that are consistent with the associated facility rating methodology or documentation for determining their facility ratings.

• Requirement R7 provides that facility ratings must be provided to other entities as specified in the requirements.

• Requirement R8 requires the identification and documentation of the limiting component for all facilities and the increase in rating if that component were no longer the limiting component (*i.e.,* the rating for the second most limiting component) for facilities associated with an Interconnection reliability operating limit, a limitation of TTC, an impediment to generator deliverability, or an impediment to service to a major load center.

• Requirement R8 also requires entities to provide information to requesting entities regarding their facilities. Requirement R8, Part 8.1 requires an entity to provide the identity of the most limiting equipment of a facility as well as the facility rating to requesting entities. Requirement R8, Part 8.2 requires an entity to provide the identity of the next most limiting equipment of a facility as well as the thermal rating of that equipment.

E. Commission Staff Paper and September 2019 Technical Conference

16. In August 2019, the Commission issued the Commission Staff Paper, ''Managing Transmission Line Ratings'' drawing on 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.[34]

17. 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.[35] Participants at the September 2019 Technical Conference included utilities (some of which implement both AARs and DLRs), technology vendors, RTO/ISO market monitors, and organizations representing customers.

18. In October 2019, the Commission requested comments on questions that arose from the September 2019 Technical Conference.[36] In response, commenters addressed issues related to AARs and DLRs, emergency ratings, and transparency, as discussed below.[37]

III. Technical Background

A. Transmission Line Rating Fundamentals

19. Transmission line ratings represent the maximum transfer capability of each transmission line. A variety of entities use them in their reliability models, including transmission providers, reliability coordinators, transmission system operators, planning authorities, transmission owners, and transmission planners. Transmission line ratings in reliability models are used to determine operating limits and can affect transmission system operator action, such as curtailment, interruption, or redispatch decisions. As market operators, RTOs/ISOs use transmission line ratings in their market models to establish commitment and dispatch. In these market models, transmission line ratings affect congestion, and, thereby, affect the prices of energy, operating reserves, and other ancillary services. Transmission line ratings are based on the most limiting of three types of transmission line ratings/limits: Thermal ratings, voltage limits, and stability limits. Thermal ratings can change with ambient conditions; however, voltage and stability limits are fixed values that limit the power flow on a transmission line from exceeding the point above which there is an unacceptable risk of a voltage or stability problem. Transmission line ratings are dictated by the most limiting element across the entire transmission facility, which includes the overhead conductors and the associated equipment necessary for the transfer or movement of electric energy across a transmission facility (*e.g.,* switches, breakers, busses, metering equipment, relay equipment, etc.).[38]

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[29] *Id.* P 51, NAESB WEQ–023 Modeling Business Practice Standards.

[30] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards Under the NERC Standards Efficiency Review,* Order No. 873, 85 FR 65,207, 172 FERC ¶ 61,225 (2020).

[31] *Id.* P 4 (noting that the Standard Efficiency Review NOPR indicated that the Commission intended to ''coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board (NAESB) business practice standards'' and that, on July 16, 2020, ''the Commission issued a NOPR in Docket Nos. RM05–5–029 and RM05–5–030 proposing to amend its regulations to incorporate by reference, with certain enumerated exceptions, NAESB's Version 003.3 Business Practices'').

[32] NERC, Reliability Standard FAC–008–3 (Facility Ratings), *https://www.nerc.com/pa/Stand/Reliability%20Standards/FAC-008-3.pdf.*

[33] Requirements R4 and R5 have been retired effective January 21, 2014.

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

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

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

[37] A list of commenters and the abbreviated names used in this NOPR appears in appendix A.

[38] The NERC Glossary defines a facility as ''a set of electrical equipment that operates as a single Bulk Electric System Element (*e.g.,* a line, a generator, a shunt compensator, transformer, etc.)'', defines a facility rating as: ''the 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*

Continued

20. Thermal ratings are 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. Transmission conductors that exceed their maximum operating temperature can sag and/or become damaged through material weakening (or ''annealing''), resulting in reduced capability and causing potential reliability and/or public safety concerns.

21. Conductor temperatures are impacted by a variety of factors, notably ambient air temperatures. Specifically, increases in ambient air temperatures tend to increase a transmission line's operating temperature. Electric power flowing through a transmission line increases the temperature of the line above ambient temperature due to the line's electrical resistance. Other conditions and phenomena also tend to increase transmission line temperature, particularly solar irradiance intensity. Conversely, some conditions and phenomena tend to lower transmission line temperature, particularly wind. Thermal transmission line limits, therefore, generally decrease with warmer ambient air temperatures and greater solar irradiance intensity, and generally increase with cooler ambient air temperatures and higher wind speeds. Engineering standards help translate line characteristics and ambient weather assumptions into transmission line ratings. The different approaches to transmission line ratings discussed below primarily reflect differences in how frequently ambient weather assumptions are updated (which can range from decades to hours or even minutes) and what types of ambient weather assumptions are updated (air temperature, solar irradiance intensity, wind speed, etc.).

B. Current Transmission Line Rating Practices

22. In practice, thermal rating methodologies have evolved along a spectrum from fully static, with no change in ambient condition assumptions for thermal limits on conductors, to nearly ''real-time'' dynamic ratings. Static ratings are intended to reflect conservative assumptions about the worst-case ambient conditions that equipment might face (*e.g.,* the hottest summer day) and are typically updated only when equipment is changed or ambient condition assumptions are updated. Thus, they often remain unchanged for years or even decades. Seasonal ratings are similar to static ratings in that they change infrequently, but they use different ambient condition assumptions for different seasons.[39]

23. Generally, AARs are transmission line ratings that apply to a time period not greater than one hour, reflect an up-to-date forecast of ambient air temperature (and possibly other forecasted inputs)[40] across the time period to which the rating applies, and is calculated at least each hour, if not more frequently. AAR implementation can be a multi-step process that requires selecting an appropriate line, receiving information about ambient air temperatures (prevailing and forecasted, typically from the National Oceanic and Atmospheric Administration or a private service), rating forecasting, and rating validation. Implementation of AARs often involves transmission owners developing electronic rating ''look-up'' tables for their transmission facilities, which yield transmission line ratings for any air temperature. Transmission line ratings are then determined by using the rating that corresponds to the ambient air temperature that is forecasted over the period of the rating (*e.g.,* hour or 15 or 5 minutes).

24. AAR methodologies usually result in higher transmission line ratings relative to seasonal or static rating methodologies because, while seasonal or static ratings are based on the conservative, worst-case temperature values, AARs are usually based on ambient air temperatures lower than the conservative, worst-case temperature values. For a small percentage of intervals, however, AARs will identify that the near-term ambient temperature conditions are actually more extreme than the long-term assumptions used in seasonal or static ratings, and will therefore result in a line rating that is lower than a seasonal or static rating would have allowed.

25. On the opposite end of the spectrum from static ratings are DLRs, which use assumptions that are updated in near real-time. In addition to ambient air temperature, DLRs can incorporate additional ambient conditions such as wind speed and direction, solar irradiance intensity (considering cloud cover), and/or precipitation. DLRs may also incorporate measurements from sensors installed on or near the line, such as wind speed sensors, line tension sensors, conductor temperature sensors, and/or photo-spatial sensors (*e.g.,* 3–D laser scanning) monitoring line sag. Such weather and other data are not immediately converted to transmission line ratings in real-time. Instead, DLR implementation combines current sensor data with data from the recent past to create reliable short-term forecasts of the relevant weather and other variables for longer periods of time (potentially as granular as five minute increments, but, more likely, larger time periods that could be as long as an hour). Such forecasts are used to develop transmission line ratings that can be depended on by system operators for a specified period (*e.g.,* an hour or 15 or 5 minutes). Under DLR approaches, the use of additional data (beyond the ambient temperature data used in AAR approaches) can allow DLRs to even more accurately reflect transfer capability.

26. DLR methodologies usually result in higher transmission line ratings relative to AAR and other methodologies. However, as discussed above for AAR, for a small percentage of intervals, DLRs will identify that the near-term weather and/or other conditions are actually more extreme than the assumptions under other methodologies, and will therefore result in a line rating that is lower than a static, seasonal, or AAR rating would have allowed. Moreover, the additional weather and conductor data that the sensors can provide, such as wind speed and direction, solar irradiance intensity, precipitation, and line conditions such as tension and sag, improve operational and situational awareness by helping transmission operators to better understand real-time transmission line conditions and potential anomalies, such as possible clearance violations or galloping.

27. While DLRs have unique benefits, they also have unique implementation challenges. The additional data and communications required under DLR approaches increase implementation costs and system complexity. DLR implementation requires the strategic deployment and maintenance of sensors. By increasing the amounts of transmission line rating data and by introducing additional communication nodes inside a transmission owner network, DLRs introduce additional physical and cyber security risks.

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of Terms Used in NERC Reliability Standards (June 2, 2020), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[39] Although transmission owners typically define seasonal ratings as summer and winter seasonal ratings, transmission owners may create more granular seasonal ratings that could include unique seasonal ratings for the spring and fall seasons.

[40] For example, PJM implements day and night ambient air temperature tables, where the night ambient air temperature table assumes zero solar irradiance. Exelon Comments at 25.

Moreover, DLRs can require additional training or knowledge for some transmission providers or transmission owner personnel.

28. DLRs are not widely deployed in the United States. Transmission owners have tested DLRs on some transmission lines,[41] but they generally have not incorporated DLRs into operations. For transmission owners in RTOs/ISOs, they must also work with the RTO/ISO to determine whether RTO/ISO Energy Management Systems (EMSs) are able to accept a frequently changing transmission line rating signal. If the RTO/ISO EMS cannot accept the information provided by DLRs, such a limitation would significantly reduce the potential benefits of DLRs.

29. Several participants at the September 2019 Technical Conference, have already implemented AARs, including AEP, Dominion, Entergy, and Exelon. ERCOT explained in its testimony that, of its nearly 7,000 transmission lines, approximately two thirds are rated dynamically using a process comparable to what we refer to as AARs.[42] Likewise, PJM explained in its post-conference comments that use of AARs is commonplace among the overwhelming majority of transmission owners in the PJM region.[43] According to Potomac Economics, Entergy and one additional transmission line owner implement AARs in MISO.[44] Outside of ERCOT and PJM, most transmission owners implement seasonal transmission ratings. Seasonal ratings are the norm among non-RTO/ISO transmission owners as well as in CAISO, ISO–NE, NYISO, MISO, and SPP, although at least some transmission owners in RTO/ISO regions use static ratings.[45]

C. Emergency Ratings

30. For short periods of time, most transmission equipment can withstand high currents without sustaining damage. This fact allows transmission owners to develop two sets of ratings for most facilities: Normal ratings and emergency ratings. Normal ratings are ratings that can be safely used continuously (*i.e.,* not time-limited) without overheating the transmission equipment. Emergency ratings are ratings that can be safely used for a limited period of time. This period of time can vary from as short as five minutes to as long as four hours or more.[46]

31. 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. In general, operating limits (*i.e.,* the maximum allowable MW flow) for any facility or set of facilities are set at a level to ensure that the flows on all facilities will be within applicable facility ratings both during normal operations and during post-contingency operations. Therefore, these operating limits create binding transmission constraints and result in congestion during normal operations and post-contingency, which increases the cost of production for electric energy. Following a contingency, if a transmission provider is able to use emergency ratings, system operators are afforded the flexibility to allow higher loading on transmission facilities for a short time while they reconfigure the transmission system, dispatch generation, or take other measures (*e.g.,* load shedding) to stabilize the system and return it to within normal limits. Because emergency ratings are generally higher than normal ratings, using emergency ratings allows for higher operating limits, and, thus, more efficient system commitment and dispatch solutions. More efficient commitment and dispatch solutions, in turn, reduce the prices paid by consumers for electric energy.

32. However, not all transmission owners use emergency ratings that are different from their normal ratings. For example, Potomac Economics, the market monitor for MISO, NYISO, ISO–NE, and ERCOT, notes that while MISO requires transmission owners to submit both normal and emergency ratings, 63% of transmission line ratings provided to MISO reflect emergency ratings that are equal to the normal ratings.[47] Generally, RTOs/ISOs do not require unique emergency ratings. Instead, transmission owners can decide whether to submit unique emergency ratings, or whether to submit emergency ratings that equal their normal ratings.[48]

D. Rating and Methodology Transparency

33. There are two categories of information relevant to transparency concerns: Transmission line rating methodologies and the resulting transmission line ratings. Generally, transmission line ratings and ratings methodologies are not currently available to transmission providers or the public at large, although certain transmission owners and/or operators make public their transmission line ratings and, less commonly, their ratings methodologies. Certain transmission providers explained that they do not provide such information because it is governed by confidentiality restrictions.[49]

34. The Commission Staff Paper observed that some entities noted the lack of transparency regarding transmission line rating information.[50] At the subsequent September 2019 Technical Conference, some participants expressed a desire for additional line rating transparency regardless of whether the Commission acts on requirements for AARs or DLRs. Potomac Economics stated that additional transparency regarding rating methodologies was ''essential'' for administering an AAR requirement.[51]

[41] For example, some prominent DLR pilot projects have been undertaken in ERCOT, NYISO, and PJM. In ERCOT, ONCOR tested conductor tension-monitor technology, conductor sag, and clearance monitors on eight transmission circuits (138 kilovolt (kV) and 345 kV). In NYISO, the New York Power Authority partnered with the Electric Power Research Institute to install sensor technology designed to measure conductor temperature, weather conditions, and conductor sag on three 230 kV ransmission lines. In PJM, pilot studies were conducted on the 345 kV Cook-Olive transmission line and an additional line to quantify the financial impact of DLRs.

[42] September 2019 Technical Conference, AD19–15, Day One Tr. at 79 (filed Oct. 8, 2019) (September 2019 Technical Conference, Day 1 Tr.).

[43] PJM Comments at 2 (citing Testimony of Michael Kormos (Exelon) at 1. (''Exelon has adopted ambient-adjusted facility ratings for the transmission facilities of five of our six utilities, with Commonwealth Edison scheduled to complete the transition to ambient-adjusted facility ratings next year.''); Testimony of Francisco Velez (Dominion) at 2–3.

[44] Potomac Economics Comments at 6–7.

[45] Commission Staff Paper at 2, 12.

[46] In practice, emergency ratings can vary significantly in duration. As was observed in the September 2019 Technical Conference, there does not appear to be clear standardization of the emergency rating timeframes. September 2019 Technical Conference, Day 1 Tr. at 175.

[47] September 2019 Technical Conference, Day 2 Tr. at 311–312.

[48] For example, SPP and ISO–NE allow their transmission owners to use unique emergency ratings, but neither RTO/ISO specifically requires them, *see* SPP Planning Criteria, Revision 2.2 (3/16/2020), Section 7.2. *See also* ISO–NE, *ISO New England Planning Procedure No. 7: Procedures for Determining and Implementing Transmission Facility Ratings in New England* (Revision 4) (Nov. 7, 2014), *https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp07/pp7_final.pdf.*

[49] MISO Transmission Owners claim that some of the information related to the limiting element used to establish a transmission line rating is ''confidential.'' MISO Transmission Owners Comments at 20; Dominion claims that FAC–008's Requirement 8 requires confidential sharing of limiting element information only with ''associated Reliability Coordinator(s), Planning Coordinator(s), Transmission Planner(s), Transmission Owner(s) and Transmission Operator(s) when requested.'' Dominion Comments at 14.

[50] Commission Staff Paper at 28.

[51] September 2019 Technical Conference, Day 2 Tr. at 309.

WATT noted that transmission owners may have an incentive to be overly conservative with their line rating methodologies and that increasing transparency around these methodologies could improve efficiency.[52]

35. At the September 2019 Technical Conference, panelists also discussed auditing of line ratings and rating methodologies. Panelists disagreed over whether methodologies and ratings were sufficiently audited by NERC Regional Entities or other parties to ensure just and reasonable rates.

36. Separate from the outreach and technical conference discussions, NERC Reliability Standard FAC–008–3 requires transmission owners to document their facility ratings methodology. While NERC Regional Entities are responsible for auditing line ratings for compliance with Reliability Standards, FAC–008–3 Requirement R8 allows other entities, including other transmission service providers, planning coordinators, reliability coordinators, or transmission operators, to request facility ratings up to 13 months later for internal examination.[53] Such data requests remain non-public.

37. Lastly, some transmission owners periodically report rating methodologies in FERC Form 715, Part IV.[54]

IV. Need for Reform

A. Transmission Line Ratings

38. For the reasons discussed below, we preliminarily 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. Because of those relationships, inaccurate transmission line ratings may result in Commission-jurisdictional rates that are unjust and unreasonable.

39. First, most transmission owners implement seasonal or static transmission line rating methodologies. Such seasonal or static line ratings are based on conservative, worst-case assumptions about the long-term conditions, such as the expected high temperatures that are likely to occur over the longer term.[55] 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 as relevant to the availability of, and arrangement for, point-to-point transmission service. Thus, they fail to reflect the true cost of delivering wholesale energy to transmission customers.

40. In the RTO/ISO markets, line ratings directly affect the dispatch and unit commitment computations by constraining power flows on individual transmission facilities. The resulting congestion costs are directly reflected in locational marginal prices (LMPs). Outside of RTOs/ISOs, LMPs are not generally used; however, transmission line ratings can still directly affect the cost to deliver wholesale energy to transmission customers by limiting transmission of electric energy under both network transmission service and point-to-point transmission service offered under the *pro forma* OATT.

41. In both RTO/ISO and non-RTO/ISO areas, incorporating near-term forecasts of ambient air temperatures in transmission line ratings would result in more accurately reflecting the actual cost of delivering wholesale energy to transmission customers. Because actual ambient temperatures are usually not as high as the ambient temperatures conservatively assumed in seasonal and static ratings, updating transmission line ratings used in near-term transmission service to reflect ambient 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 import less expensive power into what were previously constrained areas. For example, Potomac Economics has found that AAR implementation by those not already doing so in MISO alone would have produced approximately $94 million and $78 million in reduced congestion costs in 2017 and in 2018, respectively.[56] Such congestion cost changes and related overall price changes will more accurately reflect the actual congestion on the system and, similarly, more accurately reflect the cost of delivering wholesale energy to transmission customers. 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.

42. While current line rating practices usually understate transmission capability, they can also overstate transmission capability. While actual ambient temperatures are usually not as high as the assumed seasonal or static temperature input, in some instances actual ambient temperatures exceed those assumed temperatures. In those instances, seasonal or static transmission line rating methodologies result in ratings that reflect more transfer capability than physically exists, and therefore such line ratings allow access to some electric power supplies and/or demand that would not be available if ratings reflected the true transfer capability. Overstating transmission capability, like understating transmission capability, results in wholesale energy rates that fail to reflect the actual cost of delivering wholesale energy to transmission customers, but, by contrast, results in inaccurately low congestion pricing. Moreover, overstating transmission capability may risk damage to equipment, and may prevent occurrences of rates for scarcity pricing or transmission constraint penalty factors that serve as important signals to the market that more generation and/or transmission investment may be needed in the long-term.

43. Second, regarding potential DLR implementation, some RTOs/ISOs may rely on software that cannot accommodate line ratings that frequently change, such as DLRs. Without reflecting such frequent changes to line ratings, such software may serve as a barrier that prevents transmission owners in RTOs/ISOs from implementing DLRs that can better reflect the actual transmission capability of the transmission system. As noted above, in addition to ambient air temperature, other weather conditions such as wind, cloud cover, solar irradiance intensity, and precipitation, and transmission line conditions such as tension and sag, can affect the

[52] September 2019 Technical Conference, Day 1 Tr. at 23.

[53] NERC Reliability Standard FAC–008–3—Facility Ratings, Requirement R8.

[54] FERC Form 715 is a multi-part annual transmission planning and evaluation report which each transmitting utility that operates integrated transmission system facilities rated at or above 100 kilovolts (kV), must annually submit.

[55] For example, transmission providers appropriately utilize conservative long-term assumptions about long-term conditions to incorporate requests for long-term firm point-to-point transmission service, which the *pro forma* OATT defines as ''firm point-to-point transmission service under Part II of the Tariff with a term of one year or more'' (*pro forma* OATT section 1.19) and requests for network integration transmission service, whose applications require 10-year projections of all network resources (*pro forma* OATT section 29.2). Additionally, planning authorities appropriately utilize conservative long-term assumptions in the long-term transmission planning horizon and the near-term transmission planning horizon.

[56] Potomac Economics Comments at 6–7.

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 limit than AARs, which can result in rates that even more accurately reflect the costs of delivering wholesale energy to transmission customers. But, even if a transmission owner sought to implement DLRs, the RTO/ISO's EMS may not be able to accept and use the resulting transmission line rating. This inability to automatically accept and use a DLR may prevent the market from benefiting from the more accurate representation of current system conditions that would otherwise produce prices that more accurately reflect the costs of delivering wholesale energy to transmission customers. Therefore, we preliminarily find 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.

44. Third, regarding emergency ratings, current transmission line rating practices may fail to use emergency ratings, and in failing to do so, may result in ratings that do not accurately reflect the near-term transfer capability of the system and therefore may result in rates that do not reflect actual costs to delivering wholesale energy to transmission customers. As discussed above, transmission owners often develop two sets of 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.

45. In RTO/ISO markets, market models, such as security-constrained economic dispatch (SCED) and security-constrained unit commitment (SCUC) models, generally calculate resource dispatch and commitments that ensure that all facilities will be 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, SCED and SCUC models often allow post-contingency flows on 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 those 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.

46. While most or all RTO/ISO markets consider both normal and emergency ratings as part of their SCUC and SCED models, not all transmission owners have chosen to incorporate unique emergency ratings into their transmission line rating methodologies. That is, some transmission owners in RTO/ISO regions provide to the RTOs/ISOs emergency ratings that are just a copy of the normal ratings,[57] essentially creating the same situation as if the RTO/ISO did not use emergency ratings at all when modeling contingencies. As discussed above, this may result in the use of less accurate flow limits, and less accurate costs for delivering wholesale energy to transmission customers. According to Potomac Economics, for example, this failure to implement unique emergency ratings resulted in approximately $62 million and $68 million in additional costs in 2017 and in 2018, respectively, in MISO alone.[58] Therefore, we seek comment on whether not using unique emergency ratings, as discussed below, similarly may not be just and reasonable.

B. Transparency

47. We preliminarily find that the current level of transparency into transmission line ratings and transmission line rating methodologies may result in unjust and unreasonable rates. The current level of transparency may prevent transmission provider(s) and market monitors from having the opportunity to validate transmission line ratings. This may result in transmission owners submitting inaccurate near-term transmission line ratings, which may result in rates that do not accurately reflect congestion and reserve costs on the system, as discussed above. For example, without knowing the basis for a given line rating that frequently binds and elevates prices, a transmission provider and/or market monitor cannot determine whether the line rating is miscalculated or accurately calculated.

V. Discussion

A. Transmission Line Ratings

1. Comments

a. Ambient-Adjusted Line Ratings

48. At the September 2019 Technical Conference, participants and staff explored whether the Commission should require the implementation of AARs.[59] Several participants supported a requirement to implement AARs, with several stating their support for AAR implementation as a best practice. Supporters contend that while AAR implementation requires an initial investment to upgrade the EMS, these costs are a manageable way to increase transfer capability.[60] Potomac Economics noted that significant economic benefits would have accrued to market participants if all MISO transmission owners had implemented AARs and unique emergency ratings.[61]

49. Several participants did not support an AAR requirement. Ameren, on behalf of the MISO Transmission Owners, argued that AAR implementation would be costly and complex. PacifiCorp argued that the benefits of implementing AARs and DLRs would not materialize on all lines, and therefore cautioned that the Commission should not require AAR implementation on all lines.[62] Finally, Ameren argued that because forecasting was necessary for day-ahead AAR implementation, there could be liability associated with an incorrect forecast.[63]

50. Following the September 2019 Technical Conference, the Commission requested comments on all conference discussion items, including the appropriateness of a Commission requirement to implement AARs, how a requirement might be structured, whether an AAR requirement should be extended to day-ahead markets, and whether any forecasted ambient conditions other than temperature should be considered in an AAR requirement.

51. Many entities filed comments in support of a requirement to implement AARs, noting that an AAR requirement represents a cost-effective industry best practice that would achieve significant savings to ratepayers. Some transmission owners reiterated points

[57] Here we are describing the situation where the emergency ratings are *arbitrarily* set equal to the normal ratings. On the other hand, there may be some instances where, after a proper technical analysis considering the relevant rating timeframes, the emergency rating is nonetheless equal to the normal rating. As relevant to the discussion here, such ratings would be considered ''unique'' because they were developed from the appropriate, unique technical inputs.

[58] Potomac Economics Comments at 6–7.

[59] Panelists participating in the discussion of a potential requirement to implement AARs included representatives from AEP, Ameren (on behalf of the MISO Transmission Owners), CAISO, Entergy, PacifiCorp, Potomac Economics, and Vistra Energy.

[60] September 2019 Technical Conference, Day 1 Tr. at 142.

[61] *Id.* at 171.

[62] *Id.* at 163.

[63] *Id.* at 148.

made in the September 2019 Technical Conference. AEP explains that it has used AARs in real-time operations for more than a decade and that it monitors temperature zones in its regions and retrieves real-time temperature data for every state estimation process run. AEP states that AARs using real-time and next day forecasted regional temperatures can benefit customers and bring flexibility to transmission operations.[64]

52. Dominion explains that requiring the use of AARs, rather than a default temperature assumption that is ''too conservative,'' will allow transmission line ratings to better reflect forecasted conditions. Dominion cautions, however, against AARs that make overly aggressive assumptions, which would also result in the transmission system being operated ''less conservatively'' and a degradation of grid reliability.[65]

53. Similarly, Exelon states that it would not oppose a properly structured requirement to implement AARs in both real-time and day-ahead markets. Exelon explains that AARs represent a best practice and a cost-effective way to enhance transmission use to the benefit of customers.[66] As background, Exelon explains that PJM requires its transmission owners to provide ambient temperature-dependent ratings for both daytime and nighttime periods (which account for the presence or lack of solar irradiance heating), and for normal, long-term emergency, short-term emergency, and load dump conditions.[67] Exelon explains that implementing AARs results in more accurate transmission line ratings, reducing the likelihood of overloading a line and thus creating reliability benefits. Exelon reiterates its comments from the conference that, while implementing AARs requires initial investments, AARs are a cost-effective way to reduce congestion and enhance reliability.[68]

54. While generally supporting a requirement to implement AARs, AEP, Dominion, and Exelon express caution and request flexibility regarding AAR implementation. Dominion explains that it would not support a requirement for AAR implementation to be fully automated.[69] Dominion and Exelon warn that AAR implementation will not eliminate congestion.[70] Exelon further cautions that an AAR requirement should only apply to transmission facility ratings sensitive to temperature changes,[71] that transmission owners should have flexibility to determine appropriate temperature granularity,[72] and that it may not be appropriate to apply AARs to certain degraded or older assets.[73] AEP cautions that entities that have not implemented AARs before will incur some up-front costs, including internal process development and documentation costs, weather data subscriptions, software changes, and training, but explains that these costs should be manageable.[74] Exelon and AEP both also caution that AAR implementation should be applied only to real-time and day-ahead markets and should not be considered permanent solutions to address thermal constraints identified in long-term transmission planning reliability assessments.[75]

55. Both Potomac Economics and Monitoring Analytics support a requirement for transmission owners to implement AARs that must be updated hourly.[76] Monitoring Analytics states that the ''failure to use AARs means that line ratings in actual use are wrong much of the time,'' which they argue is not acceptable.[77] Potomac Economics estimates that adoption of AARs in MISO by those not already doing so would have produced approximately $78 million and $94 million in annual benefits in 2017 and 2018, respectively. Potomac Economics further estimates the savings derived from Entergy and another unnamed MISO transmission owner's current AAR implementation to have been $51.3 million over 2017 and 2018.[78] Potomac Economics explains that an AAR requirement would enhance reliability by increasing operational and situational awareness, by ensuring transmission line ratings are more accurate, and by ensuring that transmission providers have a better understanding of the capabilities of transmission facilities.[79]

56. DTE, TAPS, Industrial Customers, and OMS each make supportive comments. Citing Entergy's presentation from the September 2019 Technical Conference, DTE explains that using AARs can increase transmission line ratings by up to 25% for lower-voltage facilities and by 5% on higher-voltage facilities, and its ongoing implementation requires only ''one full-time engineer to maintain the associated in-house database, perform modeling updates, and liaison with real-time system operations personnel and IT resources to support automation of the calculations.'' [80] DTE therefore submits that AARs can be implemented without causing any undue burden.[81] DTE states that transmission owners are obligated to implement the most cost-effective solution, and given the experience of other transmission owners that have successfully implemented AARs, DTE contends that transmission owners should be required to implement AARs because they are the most cost-effective solution.[82]

57. TAPS agrees with September 2019 Technical Conference participants, such as AEP, who contended that the Commission should issue a rulemaking requiring AAR implementation, assuming appropriate safeguards.[83] TAPS encourages a requirement for AAR implementation to be part of an effort to ensure more accurate transmission line ratings, as part of good utility practice, and focusing AAR application where congestion reductions might be most meaningful.[84] To identify locations where AAR application would be beneficial, TAPS explains that RTOs/ISOs should have backstop authority to identify transmission facility candidates following a transparent process where the RTO/ISO is directed to independently evaluate the grid for beneficial AAR candidates.[85] Noting the importance for transmission line ratings to be both accurate and applied in a non-discriminatory manner, as well as the challenges of ensuring accuracy and preventing discrimination in the absence of an independent entity facilitating AAR implementation, TAPS explains that the Commission should give serious examination to AAR application in non-RTO/ISO regions.[86]

58. Industrial Customers similarly argue that the Commission, at a minimum, should require transmission owners to implement AARs on the most congested transmission lines and facilities.[87] Industrial Customers explain that AARs provide a more

[64] AEP Comments at 2.

[65] Dominion Comments at 3–4.

[66] Exelon Comments at 1.

[67] *Id.* at 25–26.

[68] *Id.* at 1, 9.

[69] Dominion Comments at 5–6.

[70] Exelon Comments at 10; Dominion Comments at 11.

[71] Exelon Comments at 22–23.

[72] *Id.* at 24.

[73] *Id.* at 23.

[74] AEP Comments at 2–3.

[75] Exelon Comments at 5; AEP Comments at 3.

[76] Potomac Economics Comments at 2–3; Monitoring Analytics Comments at 5.

[77] Monitoring Analytics Comments at 5.

[78] Potomac Economics Comments at 6–7. Potomac Economics explains that estimates of benefits will necessarily be conservative given that the shadow price would increase if the market was controlling to a lower rating.

[79] *Id.* at 8.

[80] DTE Comments at 2.

[81] *Id.*

[82] *Id.* at 3.

[83] TAPS Comments at 4–5.

[84] *Id.* at 9.

[85] *Id.* at 10.

[86] *Id.* at 11.

[87] Industrial Customers Comments at 15.

accurate representation of ATC and contend that using AARs is good utility practice by allowing transmission operators to better optimize existing circuits and reduce electric prices.[88] For these reasons, Industrial Customers contend the Commission should require the implementation of AARs, but, noting the possibility that a cost-benefit comparison may change at a very granular level, only on such facilities where AAR implementation is truly cost-effective.[89]

59. PJM explains that it has derived significant operational value in the adoption of AARs, explaining that its use of AARs has allowed it to take advantage of additional transfer capability that promotes a more reliable system dispatch.[90]

60. Other entities, while not outright supporting a requirement for AAR implementation, offer a more nuanced view. MISO states that if the Commission does require AAR implementation, that requirement should not solely focus on congested facilities. MISO explains that any transmission facility could become the next most limiting element as the system changes, and that therefore AARs should be applied to any facility where temperature is a determining factor.[91]

61. IEEE and NERC offer limited support for AAR implementation. According to IEEE, AARs provide safer transmission line ratings during periods of unexpected extreme ambient conditions exceeding the assumptions that are the basis for static ratings, provide better use of transmission assets, and reduce the need for additional infrastructure investment to service anticipated demand.[92] However, IEEE also highlights disadvantages to AAR implementation. These include necessary upgrades to EMSs, assurances that a utility's EMS is protected from sabotage and cyber tampering, and robust analysis protocols needed to convert changing temperatures into updated transmission line ratings, as well as additional work needed to document AAR protocols in a transmission line rating methodology.[93] NERC cautions that AAR implementation may not increase the reliability of transmission lines if implementation is not properly coordinated to avoid real-time operational confusion,[94] citing an example from during the 2003 blackout of a transmission line rating discrepancy between the transmission owner, transmission operator, and reliability coordinator where each had separate transmission line ratings for the same facility.[95]

62. Opposition to a requirement to implement AARs comes primarily from MISO Transmission Owners, ITC, EEI, NRECA, WATT, and AWEA. Generally, MISO Transmission Owners and ITC state that the industry is not ready to support full implementation of AARs or DLRs.[96] MISO Transmission Owners and ITC state that the Commission should allow industry to continue to explore the use primarily of AARs and secondarily of DLRs through industry groups or pilot programs.[97] MISO Transmission Owners further argue that the Commission should recognize that preserving and protecting transmission system reliability is of paramount importance, and that tying development and implementation of AARs and DLRs to financial incentives or other economic criteria without fully understanding and taking into account the impact on reliability or safety could be contrary to the reliable and safe operation of the transmission grid and create unreasonable risk.[98] One specific cause for concern, according to the MISO Transmission Owners and ITC, is that implementation of AARs can reduce some of the "margin" between what the transmission system can actually handle and how it is operated.[99] Moreover, according to MISO Transmission Owners, if real-time ambient temperatures are higher or wind is lower than forecasted day-ahead rating assumptions, AARs could lower ratings near peak load conditions, which could in turn lead to congestion and generation redispatch.[100] Citing safety concerns and the importance of ratings to reliability, ITC also warns that the Commission should not take any action that conflicts with a transmission owner's NERC's obligations.[101]

63. MISO Transmission Owners also contend that the Commission should recognize that the benefits that would be realized from the adoption of AARs or DLRs will vary by system, and may even vary within an RTO/ISO region or within a transmission system.[102] MISO Transmission Owners state that AARs and DLRs may only be cost-effective on a subset of transmission lines, and notes that transmission systems that are constrained by voltage, stability, or certain substation limitations may not benefit from AAR or DLR implementation.[103] MISO Transmission Owners further state that factors such as topology, congestion, and localized climate conditions can affect the benefits of and need for AARs.[104] MISO Transmission Owners add that implementing and maintaining the necessary sensors and making the other investments necessary to implement AARs can be costly, and make the cost of AAR implementation similar to that of DLRs implementation.[105]

64. MISO Transmission Owners argue that there are additional indirect costs to AAR implementation. According to MISO Transmission Owners, these indirect costs are primarily liability-related, including market liability, safety liability, and reliability liability, and these costs would be complex, if not incalculable, to determine.[106] MISO Transmission Owners also argue that, should the Commission require AAR implementation, the Commission should not require AARs be used in the day-ahead markets.[107] According to MISO Transmission Owners, implementation of AARs in the day-ahead markets would increase potential liability and potentially cause congestion. Specifically, MISO Transmission Owners imply that liabilities could result from adjustments to transmission line ratings in real-time should a transmission line rating be determined based on an inaccurate day-ahead forecast and cause real-time congestion and generation re-dispatch.[108] Therefore, because there are no universal benefits to AAR or DLR implementation and because of the resulting direct and indirect costs, MISO Transmission Owners argue that no universal solution is appropriate.[109]

65. EEI echoes many of MISO Transmission Owners' arguments in its opposition to an AAR requirement. EEI explains that because of the initial investment costs, and because the benefits to AAR implementation would vary considerably, a one-size-fits-all requirement to implement AARs would

[88] *Id.* at 14–15.

[89] *Id.* at 14–16.

[90] PJM Comments at 2–3.

[91] MISO Comments at 2–3.

[92] IEEE Comments at 1.

[93] *Id.* at 2–4.

[94] NERC Comments at 3.

[95] Technical Conference, Day 1 Tr. at 91.

[96] MISO Transmission Owners Comments at 1–2; ITC Comments at 2–3.

[97] MISO Transmission Owners Comments at 1–2; ITC Comments at 2–3.

[98] MISO Transmission Owners Comments at 2.

[99] *Id.* at 6; ITC Comments at 3–4.

[100] MISO Transmission Owners Comments at 13.

[101] ITC Comments at 1.

[102] MISO Transmission Owners Comments at 14.

[103] *Id.* at 8–9 (citing Commission Staff Paper at 8–9).

[104] *Id.* at 7.

[105] *Id.*

[106] *Id.*

[107] *Id.* at 12–13.

[108] *Id.* at 12–14.

[109] *Id.* at 7.

not be appropriate.[110] EEI further states that, by requiring transmission owners to consider ambient conditions in transmission line ratings, NERC Reliability Standard FAC–008–3 creates a meaningful incentive for transmission owners to implement AARs. Specifically, EEI argues that transmission owners are required to consider ambient temperatures under FAC–008–3, and are also required rate their lines using technically sound principles, and therefore, any further requirement to implement AARs is unnecessary.[111] EEI emphasizes that AARs and DLRs are only appropriate for real-time and near-real-time operations and are not appropriate to use in system planning.[112]

NRECA states that while it would support a reasoned approach to implementing transmission line rating changes, it does not support a Commission mandate to implement either AARs or DLRs.[113] NRECA does not oppose the use of AARs or DLRs in operations if there are consumer benefits to be gained, but contends that safety and reliability should remain the foremost considerations. Further, NRECA agrees with September 2019 Technical Conference participants who recommended against ''one-size-fit-all'' requirements for transmission ratings and ratings methodologies and, citing the September 2019 Technical Conference, explained that it would not be cost-effective to implement AARs or DLRs on all transmission lines.[114] For these reasons, NRECA emphasizes the need for flexibility to balance the cost and benefits of implementing these rating methods. Moreover, NRECA explains that a one-size fits-all approach poses a distinct risk to Western states and NRECA members in particular, since an AAR or DLR mandate would increase transmission costs disproportionately for rural consumers.[115]

66. WATT asserts that transmission owners should not be required to implement AARs everywhere because, according to WATT, AARs are not sufficiently conservative.[116] WATT argues that at times, AAR implementation may not be conservative enough because AAR implementation can assume too much wind, causing transmission line ratings to be too high, and possibly result in safety violations.[117] Specifically, WATT explains that wind speeds assumed by IEEE and the International Council on Large Electric Systems studies may be too high at certain temperatures and result in transmission line ratings that exceed what a transmission line can safely handle.[118]

67. Finally, rather than recommend Commission action to require AARs, AWEA recommends a process whereby transmission owners should be required to disclose transmission line ratings and, for lines whose limiting element is an overhead conductor, perform a cost-benefit study of the deployment of DLR or other congestion mitigation technologies.[119] AWEA further contends that for lines that are not conductor-limited, transmission owners should be required to perform a cost-benefit study of the upgrade of the terminal equipment or other congestion mitigation technologies.[120] However, in the absence or delay of DLR implementation, AWEA adds that AARs also present benefits and should be considered for implementation.[121]

b. Dynamic Line Ratings

68. WATT states that DLRs are more accurate than AARs, and that DLRs reduce uncertainty relative to AARs by providing accurate information about sag, clearances, and conductor temperatures.[122] WATT recommends transmission owners be required to, for each line that is or is forecast to become heavily congested, disclose nominal ratings and perform a cost-benefit study of the deployment of DLRs, other congestion mitigation technologies, and/or upgrading the terminal equipment, as appropriate.[123] WATT concedes that security can be a concern, but should not be used as a red herring to avoid improvements to the grid's reliability and efficiency.[124]

69. Some commenters recommend pilot programs, a limited or staged implementation of DLRs, and/or requirements to ensure transmission operators can accept and use DLRs, noting these would be helpful in overcoming the challenges related to DLR implementation. Monitoring Analytics recommends that the Commission direct all transmission owners in PJM to start DLR pilot programs.[125] PJM also supports DLR pilot projects, and notes that DLR pilot projects have already taken place on its system.[126] Dominion states that it has partnered with LineVision and EPRI in pilot projects focused on evaluating DLR sensor installations and validating the sensors' data, and contends that more pilot programs could facilitate the adoption of DLRs.[127] Potomac Economics and MISO state that they do not oppose DLR implementation, but contend that AAR implementation should be prioritized.[128] In considering where to begin DLR implementation, WATT contends that the Commission could consider factors such as whether a line is thermally limited, congested, or the average wind speed or other weather parameters would have a strong bearing on the line's rating. WATT also contends that DLRs should be made available at a customer's request.[129]

70. Although some commenters highlight the benefits of DLRs, others stress the challenges associated with DLR implementation. For example, Dominion cautions that DLRs provide only marginal benefits compared to AAR implementation in real-time operations, but also include additional challenges, increased operational burdens, and likely higher uncertainty.[130] MISO, PJM, and MISO Transmission Owners caution that data verification would be necessary when implementing DLRs to protect against intrusion and corruption.[131] MISO Transmission Owners further caution that implementation of DLRs is likely to be complex, resource-intensive, and costly.[132] EEI and Exelon note that implementing DLRs includes additional challenges, such as placing sensors in remote locations, ensuring the cyber security of sensors, and various additional costs.[133] Other commenters urge the Commission to exercise caution regarding further DLR requirements, including ITC, MISO, and PJM,[134] which explain that DLR is a technology still under development and therefore further pilot projects to evaluate the appropriateness of DLR requirements

[110] EEI Comments at 5–7.

[111] *Id.* at 7–8.

[112] *Id.* at 9–10.

[113] NRECA Comments at 2–5.

[114] *Id.* at 4 (citing the opening statements of Dennis D. Kramer on behalf of the MISO Transmission Owners and Rikin Shah on behalf of PacifiCorp, located in Technical Conference, Day 1 Tr. at 147 and 163–65, respectively).

[115] *Id.* at 5–6.

[116] WATT Comments at 2.

[117] *Id.* at 2–5.

[118] *Id.* at 2–4.

[119] AWEA Comments at 2.

[120] *Id.*

[121] *Id.*

[122] WATT Comments at 5.

[123] *Id.* at 2–5.

[124] WATT Reply Comments at 4.

[125] Monitoring Analytics Comments at 5–6.

[126] PJM Comments at 1, 4–6.

[127] Dominion Comments at 8–9.

[128] MISO Comments at 3, 6; Potomac Economics Comments at 13.

[129] WATT Reply Comments at 3.

[130] Dominion Comments at 8–11.

[131] MISO Comments at 8–9; PJM Comments at 8; MISO Transmission Owners Comments at 25.

[132] MISO Transmission Owners Comments at 15–16, 25.

[133] EEI Comments at 8–10; Exelon Comments at 11–13.

[134] ITC Comments at 3–4; MISO Comments at 5–6; PJM Comments at 4–6.

are needed [135] and also that, since AAR implementation is more cost-effective, DLR cost-effectiveness should be reevaluated in light of any AAR requirement.[136]

71. Comments indicate that the ability to incorporate DLRs is uneven. Dominion states that its EMS cannot incorporate DLRs, and that, while PJM's EMS can accept DLRs, that capability is unused. Dominion states that relative to AAR implementation, EMS upgrades are typically needed to support DLRs, which would require fundamental data schema updates. Dominion notes that most ''off-the-shelf'' EMSs can accommodate AARs because they have alternative line ratings sets that can be switched on or off according to ambient temperature.[137]

72. MISO contends that it can accept DLRs, but not the information necessary to calculate the rating itself.[138] MISO Transmission Owners state that some RTOs/ISOs may have the capability now to change transmission line ratings ''on-the-fly'' through their EMSs, while other RTOs/ISOs and their transmission owners would have to update and revise multiple systems to use DLRs in real-time and day-ahead markets.[139] WATT concurs, explaining that RTOs/ISOs and transmission operators currently vary in their ability to incorporate DLRs based on various factors.[140]

73. The idea of requiring studies on the cost-effectiveness of DLRs was generally supported, but commenters disagreed on study details and on whom should conduct the study. WATT and Industrial Customers recommend that RTOs/ISOs study the benefits and effectiveness of DLR on the most congested, thermally limited lines.[141] Dominion states that it is open to studying its most congested lines to determine DLR's cost-effectiveness, but argues that PJM is better suited to assess the costs and congestion relief associated with DLR adoption.[142]

74. MISO Transmission Owners suggest that there may be no single metric for determining which congested lines to target.[143] Exelon states that a DLR cost-effectiveness study could duplicate existing processes, noting that in PJM, transmission owners are able to propose advanced technologies as possible transmission solutions.[144]

c. Emergency Ratings

75. At the September 2019 Technical Conference, Entergy stated that it uses short-term emergency ratings on less than 10% of its facilities.[145] In explaining its reluctance to implement emergency ratings, Entergy stated that the use of emergency ratings carries a high degree of risk based on its potential to degrade the applicable transmission facility, and that the risk and trade-offs must be very carefully balanced.[146] Moreover, given the reliability risks, Entergy further contended that emergency ratings should not be used for economic purposes.[147]

76. While most post-September 2019 Technical Conference comments focused on normal ratings, some commenters also described the current implementation and availability of emergency ratings, typically used for specific durations post-contingency. Commenters discussing emergency ratings include Exelon, PJM, Dominion, Industrial Customers, Potomac Economics, and Monitoring Analytics.

77. Exelon and Monitoring Analytics note that, in addition to normal transmission line ratings, PJM transmission owners are required to provide short-term emergency transmission line ratings, long-term emergency transmission line ratings, and load-dump transmission line ratings.[148] Exelon states that, like AARs, emergency ratings also may not be sensitive to changes in ambient air temperatures if the equipment rating is not sensitive to ambient air temperatures or if the transmission facility is not thermally limited.[149] Monitoring Analytics explains that while PJM typically uses the long-term four-hour emergency rating in SCED/SCUC modeled contingencies, there is no requirement that the ratings differ for these operating conditions.[150]

78. PJM points out that any permitted use of emergency ratings is documented within PJM manuals.[151] Dominion explains that the implementation of emergency ratings, if used, typically assumes first or second contingency conditions, and that the development and usage of emergency ratings should be documented in each transmission owner's transmission line rating methodology.[152] Finally, Industrial Customers clarify that PJM's tariff allows certain flowgate calculations to use emergency ratings.[153]

79. Potomac Economics explains that because most binding real-time constraints are based on contingencies, operators model the additional flows that would occur on a monitored facility post-contingency, and MISO must be prepared to return flows below normal ratings within the prescribed time period. Thus, Potomac Economics states that unique emergency ratings may enable operating at higher levels for longer post-contingency.[154] Potomac Economics and Industrial Customers [155] explain that the MISO Transmission Owners Agreement calls for transmission owners to provide emergency ratings, which can reliably accommodate flow for two to four hours, for all contingency constraints.[156] However, Potomac Economics notes that 63% of all post-contingency ratings used by MISO are actually the normal ratings.[157] Had unique emergency ratings been used in MISO, Potomac Economics contends, the market cost savings would have been approximately $62 and $68 million in 2017 and 2018, respectively.[158]

2. Proposal

80. To remedy potentially unjust and unreasonable rates, we make several proposals related to AARs, DLRs and emergency ratings. We propose to require all transmission providers to implement AARs on the transmission lines over which they provide transmission service. We propose a staggered approach to the proposed AAR requirement that would prioritize implementation on congested lines (within one year from the date of the compliance filing for implementation of the proposed reforms to become effective), and propose to require a less aggressive implementation of AARs on all other lines (within two years from the date of the compliance filing for implementation of the proposed reforms to become effective).

81. In addition, we propose to require all RTOs/ISOs to implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least

[135] PJM Comments at 5–6; ITC Comments at 3–4.

[136] MISO Comments at 6.

[137] Dominion Comments at 8.

[138] MISO Comments at 5.

[139] MISO Transmission Owners Comments at 16.

[140] WATT Comments at 7.

[141] *Id.;* Industrial Customers Comments at 16.

[142] Dominion Comments at 10–11.

[143] MISO Transmission Owners Comments at 16–17.

[144] Exelon Comments at 29–30.

[145] Technical Conference, Day 1 Tr. at 159.

[146] *Id.*

[147] *Id.* at 293–94.

[148] Exelon Comments at 25; Monitoring Analytics Comments at 3.

[149] Exelon Comments at 10.

[150] Monitoring Analytics Comments at 3.

[151] PJM Comments at 7.

[152] Dominion Comments at 15.

[153] Industrial Customers Comments at 17.

[154] Potomac Economics Comments at 4.

[155] Industrial Customers Comments at 12 (citing MISO, MISO Rate Schedules, Transmission Owner Agreement, Appendix B, Section V (30.0.0)).

[156] Potomac Economics Comments at 4.

[157] *Id.* at 5.

[158] *Id.* at 6.

hourly. We also seek comment on whether to apply this requirement to transmission providers located outside of RTO/ISO markets.

82. Finally, with regard to emergency ratings, we seek comment on whether to require transmission providers to use unique emergency ratings.

a. Ambient-Adjusted Line Ratings and Seasonal Line Ratings

i. Proposed Requirements

83. Having preliminarily found that the use of transmission line ratings that are based on long-term assumptions is not just and reasonable, we propose, pursuant to section 206 of the FPA to revise the *pro forma* OATT to require all transmission providers to implement AARs and seasonal line ratings on the transmission lines over which they provide transmission service, under certain circumstances. This requirement would ensure that transmission line ratings accurately reflect the availability of transmission in real-time.

84. In proposing to require the implementation of AARs and seasonal transmission line ratings, we propose to define transmission line ratings as the maximum transfer capability of a transmission line, computed in accordance with a written line rating methodology and consistent with Good Utility Practice, considering the technical limitations (such as thermal flow limits) on conductors and relevant transmission equipment, 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.

85. We propose to implement these requirements through a new Attachment M to the *pro forma* OATT titled Transmission Line Ratings. Within the proposed Attachment M, different line rating requirements would apply in the context of different types of transmission service, as discussed below.

(a) Point-to-Point Transmission Service

86. The first proposed AAR requirement applies to the availability of and requests for ''near-term point-to-point transmission service,'' (under section 15, section 17, and section 18 of the *pro forma* OATT) which we propose to define as point-to-point transmission service ending within 10 days of the date of the request. We propose to require transmission providers to use AARs as the relevant transmission line ratings when (1) evaluating requests for near-term point-to-point transmission service, (2) responding to requests for information on the availability of potential near-term point-to-point transmission service (including requests for ATC or other information related to potential service), and (3) posting ATC or other information related to near-term point-to-point transmission service to the their OASIS site. Through the definition of ''near-term point-to-point transmission service,'' we propose to limit the AAR requirement to requests for transmission service ending within 10 days of the date of the request. We propose this 10-day limit both because it appears to be a reasonable cut-off beyond which forecasts may not be accurate enough for AARs to provide significant value, and because we believe such a limit would reasonably accommodate requests for weekly point-to-point transmission service. However, we seek comment on the appropriateness of this 10-day limit.

87. For other (longer-term) point-to-point transmission service requests, we propose to require transmission providers to use seasonal line ratings as the relevant transmission line ratings when (1) evaluating requests for such service, (2) responding to requests for information on the availability of such service (including requests for ATC or other information related to such potential service), and (3) posting ATC or other information related to such service to their OASIS site. In proposing to require seasonal ratings, however, we propose to limit the duration of a season to three months. We do not propose to require the use of AARs for evaluations of longer-term service because we expect that 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.

88. We also propose to require that transmission providers use AARs 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) if such curtailment or interruption is both necessary because of a reduction in transmission capability anticipated to occur (start and end) within the next 10 days. For determining the necessity of curtailment or interruption of point-to-point transmission service in other (beyond 10 days) situations, we propose to require transmission providers to use seasonal line ratings as the relevant transmission line ratings.

(b) Network Transmission Service

89. For network transmission service, we propose 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 such designations are generally long-term requests and seasonal line ratings better reflect conditions over a longer-term than AARs. In proposing to require seasonal ratings for evaluation of network service requests, however, we propose to limit the duration of a season to three months. Additionally, we propose to require that transmission providers use AARs as the relevant transmission line ratings when determining whether to curtail network service or secondary network service (under section 33 of the *pro forma* OATT) or redispatch network service or secondary network 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. For determining the necessity of curtailment or redispatch of network service or secondary network service in other (beyond 10 days) situations, we propose to require transmission providers to use seasonal line ratings as the relevant transmission line ratings.

(c) RTOs/ISOs

90. With respect to RTOs/ISOs, we recognize that 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. To accommodate these variations, we propose that RTOs/ISOs comply with the proposed requirements by revising their tariffs 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 reliability unit commitment or reliability assessment commitment. For the real-time market, we propose that RTOs/ISOs update the AARs at least hourly. For any point-to-point transmission service offered by RTOs/ISOs (*e.g.,* at their borders), we propose that the AAR requirements discussed above for point-to-point service would apply.

(d) Implementation Timeline

91. We propose to apply the proposed requirements for AARs and seasonal line ratings to all transmission lines, rather than targeting only congested transmission lines, as suggested by some commenters. However, we propose to prioritize the implementation of AARs and seasonal line ratings on historically congested transmission lines. Specifically, we propose to require that AARs and seasonal line ratings be implemented on historically congested lines within one year from the date of the compliance filing for implementation of any final rule, and on all other lines within two years from the date of the compliance filing for implementation of any final rule. For purposes of this proceeding, we propose that the term ''historically congested line'' mean a transmission line that was congested at any time in the five years prior to the effective date of any final rule.[159]

92. We propose to require implementation of AARs on *all* transmission lines and not only on congested lines, because any transmission facility, whether or not historically congested, could become the most limiting element as the system changes, a point argued by MISO.[160] The 2019 FERC NERC Staff Report on the January 2018 South Central cold weather event illustrates this point.[161] As shown in that event, during times of emergency or system stress, flows may change considerably from normal operations and the increased transmission capability provided through AARs may prove valuable even on lines not typically congested.

93. Nevertheless, we recognize that a staggered implementation schedule would allow RTOs/ISOs and transmission owners to focus implementation on transmission lines where AAR implementation is likely to provide the most benefits and gain operational experience with the new AAR requirements prior to full implementation.

(e) Implementation Considerations

94. As a practical matter, the proposed requirements related to AARs and seasonal line ratings would entail specific implementation and on-going obligations on the part of the transmission provider. First, the proposed AAR requirement would necessitate that transmission providers implement an automated system that can take as an input a 10-day forecast of ambient air temperatures at locations across its service area, and calculate up-to-date AAR values for each of the 240 hours in the next 10 days and for each of their transmission lines. Under the proposed requirement, for an AAR value to be ''up-to-date,'' a transmission provider must update AAR values at least every hour. We propose that transmission providers use such AAR values when evaluating requests for transmission service (or developing ATC or other information related to potential transmission service) that will occur within the next 10 days by determining (among other things) whether the transmission provider can accommodate the requested service request without violating the AAR in any hour.

95. Under the proposed AAR requirement, transmission providers would also need to arrange to have the appropriate forecasts available to support the AAR determinations discussed above. Based on information from the 2017 Idaho National Laboratory conference on DLRs, we understand that existing users of advanced line ratings such as AARs or DLRs use a variety of approaches to produce those ratings and the forecasts that underly them. Such approaches range from using vendors to handle most of the tasks related to developing forecasts and related line ratings, to performing much or most of those tasks in-house based on developed expertise and a subscription to a weather data service, with various approaches in between. We do not propose to stipulate the approach that transmission providers take to develop AAR values under our proposed requirements, as long as they execute these responsibilities consistent with good utility practice.

96. The proposed seasonal line rating requirement, as defined in proposed Attachment M, would require similar implementation obligations as for the proposed AAR requirement discussed above, although for seasonal line ratings the transmission provider would be (1) calculating line ratings for future years (instead of calculating ratings for all hours within the next 10 days for AARs), and (2) running the seasonal rating system and calculating seasonal ratings every month (instead of calculating AARs at least every hour).

97. System safety and reliability are paramount to the proposed requirements for transmission line ratings. The proposed tariff language requires the transmission provider to develop transmission line ratings (including the forecasts that underpin AARs and seasonal line ratings) consistent with good utility practice, and the definition of ''Good Utility Practice'' in section 1.15 of the *pro forma* OATT requires consistency with safety and reliability, among other things. While we expect the nature of our proposed requirements to provide transmission providers with the latitude (and obligation) to develop accurate, safe, and reliable line ratings in the first instance, we also propose, in an abundance of caution, to make explicit in the tariff language proposed herein that if a transmission provider determines, consistent with good utility practice, that it must temporarily use a rating different than otherwise required by the tariff in order to ensure the safety or reliability of the transmission system, it may do so. While we expect that such alternate line rating authority would be needed infrequently, if ever, we provide the clarification related to such temporary ratings to resolve any instance where a transmission provider reasonably believes that the tariff requirements for transmission line ratings conflict with system safety or reliability.

ii. Justification and Response to Comments

98. 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.[162] For example, as noted above, Potomac Economics estimates that the benefits to AAR implementation in MISO alone would have produced approximately $94 million and $78 million in reduced congestion costs in 2017 and in 2018, respectively.[163] While several entities note implementation costs as a barrier, these costs are mostly initial investments in upgraded OASIS and/or EMS and ratings databases.[164] Once

[159] Congestion is a characteristic of the transmission system produced by a binding transmission constraint such that the rates for wholesale electric energy, exclusive of losses, at different locations of the transmission system are not equal.

[160] MISO Comments at 2–3.

[161] 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.*

[162] AEP Comments at 3.

[163] Potomac Economics Comments at 6–7.

[164] While most commenters only mention the need for software changes (AEP Comments at 3) or mention the need for EMS upgrades and ratings databases to ensure AARs are implemented in near-term transmission service (Exelon Comments at 5–6), we also note that OASIS and/or related systems might also need to be upgraded in order to ensure ATC postings for near-term point-to-point transmission service transmission service requests

Continued

these systems are upgraded, adding AARs to additional lines appears to have a minimal incremental cost.[165]

99. Between the two possible approaches to increasing transmission line rating accuracy, AARs and DLRs, our proposal to require transmission providers to implement AARs in near-term transmission service is based on our preliminary finding that an AAR requirement strikes a more appropriate balance between benefits and challenges. While DLRs can represent more accurate transmission line ratings than AARs, DLRs also present additional costs and challenges that AARs do not present. Relative to AARs, these additional costs and challenges include placing sensors in remote locations, ensuring the cyber security of sensors, and various additional costs.[166] However, we seek comment on whether to require transmission providers to implement DLRs across their systems or on certain transmission lines that have the most to benefit from a dynamic rating.

100. In response to comments from OMS and Potomac Economics that suggest the Commission focus on the most heavily congested lines,[167] we note that our proposal, as discussed above, is to prioritize the implementation of AARs on historically congested transmission lines first.

101. In response to concerns articulated by MISO Transmission Owners that day-ahead forecasts could be inaccurate, causing differences between day-ahead and real-time transmission line ratings and therefore uplift,[168] we observe that day-ahead markets already rely upon forecasts for weather to inform next-day load and intermittent generation availability. Instead, we agree with PJM that temperatures can be forecast within a reasonable degree of certainty,[169] and we note that within our proposal transmission providers can (consistent with good utility practice) determine the needed degree of certainty when constructing their forecasts of ambient air temperature. We also preliminarily agree with MISO 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.[170]

102. We agree with some commenters that 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.[171] Our proposed *pro forma* OATT language accommodates such transmission lines without requiring unwarranted calculations or updates. Specifically, our proposed *pro forma* OATT language provides that where the transmission provider determines that the rating of a transmission line is not affected by ambient air temperature, the transmission provider may use a transmission line rating for that line that is not an AAR or seasonal line rating.

103. Finally, in response to Exelon's comments that AARs should not be implemented in transmission planning, we agree and reiterate that we are only proposing to require AAR implementation for certain aspects of near-term transmission service.[172]

104. Some entities argue that requiring AAR implementation would lead to operational and reliability concerns. MISO Transmission Owners caution that any AAR requirement could make operational or safety incidents more likely by reducing some of the margin between what a set of transmission facilities can safely handle at that point in time and the current operating levels.[173] ITC and NRECA raise similar reliability questions.[174] WATT contends that at times, AAR implementation may not be conservative enough because AAR implementation can assume too much wind. We do not find these concerns persuasive. We note that the ''safety margin'' cited by commenters is not dependable—it exists only during periods where the ambient air temperature happens to be lower than the temperature assumed when the static or seasonal line rating was calculated. We further note that the margin is lowest precisely during the hottest periods, which represent periods of high system stress when a dependable reliability margin would be most valuable. Furthermore, transmission providers that find they need a reliability margin have existing Commission-approved mechanisms, such as the transmission reliability margin (TRM) component of ATC, for establishing such a margin on a consistent and transparent basis. With respect to assumptions about ambient conditions, under our proposal, transmission owners have latitude, consistent with good utility practice, to develop assumptions about ambient conditions that result in transmission line ratings that reflect what transmission flows the system can safely and reliably accommodate.

105. Moreover, as Exelon points out, AARs would correct the existing occasional overestimations of transmission line ratings during periods where the actual ambient air temperature is greater than the temperature assumed when the rating was calculated. As a result, we believe that implementation of AARs will reduce transmission line ratings when extreme high temperature events occur, reducing the likelihood of inadvertently overloading a transmission line.[175] Moreover, consistent with PJM's and Potomac Economics' comments, we believe that because AARs will typically increase transmission line ratings when actual temperatures are lower than long-term assumptions, the resulting increased transmission capability will provide operators additional flexibility, which promotes reliability.[176] Specifically, by increasing the available transmission capability, system operators would be provided more options to manage congestion, and potentially ameliorate system conditions during an emergency. This is consistent with the 2019 FERC NERC Staff Report on the January 2018 South Central cold weather event, which, for example, identified and recommended adoption of transmission line ratings that better consider ambient temperature conditions. In this instance, implementing AARs would have been one way to potentially introduce additional transmission capability, which would have provided operators additional flexibility to transfer additional power to an area experiencing a potential reliability event, and thereby preventing the need for possible generator redispatch (reducing available contingency reserves), transmission reconfiguration,

also reflect AARs. For this reason, we describe initial costs to include OASIS and/or EMS upgrade costs.

[165] AEP Comments at 2–3.

[166] EEI Comments at 8–10; Exelon Comments at 11–13.

[167] OMS Comments at 2; Potomac Economics Comments at 9–10.

[168] MISO Transmission Owners Comments at 7.

[169] PJM Comments at 3.

[170] MISO Comments at 3.

[171] Dominion Comments at 3; Exelon Comments at 10, 22–23; September 2019 Technical Conference, Day 1 Tr. at 141 (AEP opening statement to Panel Three).

[172] Exelon Comments at 4–5.

[173] MISO Transmission Owners Comments at 6.

[174] ITC Comments at 3–4; NRECA Comments at 3.

[175] *See* Exelon Comments at 9.

[176] *See* PJM Comments at 2; Potomac Economics Comments at 8.

and/or transmission loading relief,[177] and helping mitigate future cold weather reliability events.[178] Implementing AARs may also improve the ability to schedule and perform planned equipment outages for maintenance purposes and project upgrades.[179]

106. Additionally, RTOs/ISOs already periodically request *ad hoc* transmission line rating changes based on differences between actual and assumed ambient temperatures.[180] These requests are typically needed to either manage congestion or support reliable grid operations, but further demonstrate the benefits of AAR implementation. Our proposed AAR requirements would help ensure all market participants are consistently able to access the benefits of such transmission line rating changes.

b. RTO/ISO Capability To Allow Electronic Updates to Line Ratings

107. Having preliminary found above that the use of transmission line ratings that are based on long-term assumptions may not be just and reasonable, we propose, pursuant to section 206 of the FPA, to revise the Commission's regulations 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. We propose to require that such data be submitted by transmission owners directly into an RTO's/ISO's EMS through Supervisory Control and Data Acquisition (SCADA) or related systems.[181] Absent these capabilities, 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.

108. We expect that many of the systems and procedures RTOs/ISOs would need to develop under this proposal are likely to already be required as part of compliance with the requirement proposed in the previous section for transmission providers to adopt AAR. Nonetheless, we seek comment on the additional costs, if any, needed to comply with this proposed requirement that RTOs/ISOs also be able to accommodate frequently updated transmission line ratings from transmission owners. We also seek comment on whether there is any need to extend this same requirement to transmission providers that operate outside of an RTO/ISO.

109. Finally, we seek 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.

c. Emergency Ratings

110. We seek comment on whether to require transmission providers to use unique emergency ratings. As discussed above, we expect that such ratings would not be arbitrarily set equal to the normal ratings, but rather developed from the appropriate, unique technical inputs.[182] We understand that many RTOs/ISOs already have requirements in place for transmission owners to provide emergency ratings. However, we also understand that many of the emergency ratings provided to RTOs/ISOs by transmission owners may be the same as the normal (pre-contingency) ratings. While Potomac Economics explains that 63% of all post-contingency ratings used by MISO are the same as their normal ratings,[183] we do not have comparable information from other RTO/ISO regions or information regarding whether non-RTO/ISO regions tend to use unique emergency ratings. For this reason, we seek comment on the degree to which other transmission providers use or are provided with unique emergency ratings and the emergency rating durations that are commonly used.

111. We recognize that there may be tradeoffs in requiring transmission owners to implement unique emergency ratings and therefore seek comment on the costs and benefits of such a requirement. On one hand, as Potomac Economics explains, emergency ratings result in additional capability being made available in shorter timeframes.[184] Because 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.[185] Such additional transmission capability can provide significant cost savings and afford transmission providers additional flexibility in how to respond to unforeseen events.

112. On the other hand, we recognize that there are concerns that the use of emergency ratings could impact reliability. As Entergy explained in the September 2019 Technical Conference, the use of emergency ratings may degrade affected transmission facilities and ultimately reduce the equipment's useful life.[186] Therefore, we request comment on whether and how a requirement to implement unique emergency rating would impact the useful life of transmission equipment as well as on the feasibility of calculating emergency ratings on transmission equipment other than conductors and transformers.

B. Transparency

113. While some transmission owners and/or operators make both their transmission line ratings and/or ratings methodologies public, many do not. While NERC Regional Entities are responsible for auditing line ratings for compliance with Reliability Standards, FAC–008–3 R8 allows other entities, including other Transmission Service Providers, Planning Coordinators, Reliability Coordinators, or Transmission Operators, to request facility ratings up to 13 months later for internal examination.[187] Such data requests remain non-public. However, NERC has proposed retiring FAC–008–3 R8, which would end the option of non-public facility rating requests.[188]

1. Comments

114. During the September 2019 Technical Conference, some participants expressed a desire for additional transmission line rating transparency. Potomac Economics stated that additional transparency regarding rating methodologies was ''essential'' for administering an AAR requirement.[189] WATT noted that transmission owners may have an incentive to be overly conservative with

[177] FERC and NERC Staff Report at 56–57.

[178] *Id.* at 96.

[179] Commission Staff Paper at 12 (describing outreach discussions that noted that the increased transfer capability, which typically results from *ad hoc* transmission line rating uprates (but would also result from AAR implementation) provides RTOs/ISOs additional options to manage challenges due to maintenance outages).

[180] *Id.* at 10 and 21.

[181] The NERC Glossary defines ''Supervisory Control and Data Acquisition'' as: ''A system of remote control and telemetry used to monitor and control the transmission system.'' NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 2, 2020), *https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.*

[182] *See supra* note 7, at P6 and note 58 at P 46.

[183] Potomac Economics Comments at 5.

[184] *Id.* at 4.

[185] *See supra* P 31.

[186] September 2019 Technical Conference, Day 2 Tr. at 293–294.

[187] NERC Standard MOD–001–1a—Available Transmission System Capability, R9.

[188] NERC, Petition of the North American Electric Reliability Corporation for Approval of Revised and Retired Reliability Standards Under the NERC Standards Efficiency Review, Docket No. RM19–16–000 (filed June 7, 2019). In the SER NOPR, the Commission sought further information on NERC's proposed retirement of FAC–008 R7 and R8 inquiring how such requirements are redundant.

[189] Michael Chiasson, Potomac Economics, *FERC Technical Conference on Managing Line Ratings: AD19–15 Panel 5—Transparency of Transmission Line Rating Methodologies* (Sept. 11, 2019).

their transmission line rating methodologies, and that increasing transparency around these methodologies could improve efficiency.[190] Conversely, many transmission owners at the September 2019 Technical Conference stated that they did not believe additional transparency requirements should be required.[191]

115. Arguing in favor of further transparency, Potomac Economics presented data showing a large variation in transmission line ratings for similar lines. In addition, Potomac Economics pointed to instances when the same ratings were used for a given transmission line in both summer and winter, and instances in which the same ratings were used for both emergency and normal operations. Potomac Economics explained that, in MISO, 30% of lines use the same ratings for summer as they do for winter. Potomac Economics further noted that, at least during the winter, 63% of lines use emergency ratings that are equal to their normal ratings.[192]

116. However, some panelists argued that current transparency levels were adequate. For example, AEP stated that it has shared details of its facility rating methodology and assumptions in past technical industry publications and noted that review of facility rating parameters and assumptions is common in competitive transmission development.[193] MISO Transmission Owners stated that FERC Form No. 715 data in many cases describe the rating methodology.[194] Similarly, the Exelon representative stated that their NERC Regional Entity, ReliabilityFirst, validates some of Exelon's ratings against the ratings methodology Exelon provides. Exelon stated that PJM publishes ratings and guidelines for transmission owners on facility ratings, and that Exelon tries to make their methodology closely conform to PJM's guidelines.[195] NYISO noted that it publishes seasonal rating sets as part of its operating studies, making them available to all interested parties. NYISO also stated that it makes the transmission line ratings to which it secures the system available on a limited basis to all interested parties.[196]

117. Regarding RTO/ISO audits of transmission line ratings, MISO indicated that their audit process was more of a ''sanity check'' rather than a comprehensive validation of line ratings.[197] Similarly, SPP described its use of ''reasonability limits'' that gets the transmission owner to ''sign-off'' on upper and lower bounds to cap the amount by which transmission line ratings can change and thereby ''get rid of possible erroneous data or anything else that shouldn't be used.'' [198]

118. Following the September 2019 Technical Conference, the Commission requested comments on a variety of issues involving transparency. Specifically, the Commission asked whether transmission owners' transmission line rating methodologies and transmission line ratings should be made more transparent, and, if so, how and to what extent. The Commission requested comment on who should have access to this information. The Commission also requested comment on whether transmission owners or other entities, such as NERC Regional Entities or RTOs/ISOs, should be required to develop a database to document each transmission facility's most limiting element, what burdens would be associated with reporting and maintaining such a database, and who should have access to such a database and what levels of confidentiality protections would need to exist for such a limiting elements database. Finally, the Commission asked whether requests from transmission system operators to transmission owners to allow an *ad hoc* increase in transmission line ratings above seasonal or static ratings should be publicly posted.

119. Commenters were divided over the extent to which the Commission should require further transparency with regard to transmission line ratings and transmission line rating changes. Commenters in support of greater transmission line rating methodology transparency include Potomac Economics and Monitoring Analytics, which argue that transmission line rating methodologies should be fully transparent and public.[199] Potomac Economics contends that, should AARs be required, additional transparency regarding rating methodologies and independent oversight is ''essential.'' Potomac Economics states that very little information is shared with MISO on transmission owner rating methodologies or calculations, and that the ability to validate transmission line rating methodologies and calculations by RTOs/ISOs and other transmission providers would enhance reliability by increasing operational and situational awareness and identifying incorrect ratings.[200]

120. OMS agrees that rating methodologies should be as transparent as possible and suggests incorporating the transparency model applied to load forecasting methodologies.[201] Industrial Customers also support methodology transparency, suggesting that the Commission enable market monitors, customers, and other stakeholders (such as state commissions) to have broad access to transmission line rating methodologies, assumptions, and values.[202] PJM supports a requirement for additional transmission line rating transparency, explaining that it currently posts ratings on the PJM website every 15 minutes, including ad hoc changes.[203] DTE states that transmission owners currently have a monopoly on all transmission line rating information, and suggests that enhanced transmission line rating transparency could help identify more cost-effective congestion management solutions.[204] TAPS agrees that greater transmission line rating transparency is essential,[205] encouraging the Commission to enforce greater transmission line rating accuracy through FPA section 206 authority regarding non-discriminatory open access instead of through FPA section 215 authority over reliability.[206] Finally, WATT also suggests that additional transmission line rating transparency is appropriate.[207] WATT contends that transmission owners should face no additional litigations risk if they post and follow their transmission line rating methodologies and are subject to audit by an independent entity. Instead, WATT suggests that more accurate transmission line ratings should reduce litigation risks.[208]

121. Other commenters, while not fully opposed, were less supportive of increased rating methodology transparency, citing reasons such as lack of need and concerns that their ratings will be challenged and subject to increased litigation. Dominion, EEI, Exelon, MISO Transmission Owners, and AEP all generally contend that the

[190] September 2019 Technical Conference, Day 1 Tr. at 23 and 25.

[191] *Id.* at 281–82.

[192] September 2019 Technical Conference, Day 2 Tr. at 311–12.

[193] AEP Comments at 5.

[194] September 2019 Technical Conference, Day 2 Tr. at at 322.

[195] *Id.* at 297.

[196] *Id.* at 243.

[197] *Id.* at 264.

[198] *Id.* at 247.

[199] Potomac Economics Comments at 15; Monitoring Analytics Comments at 4.

[200] Potomac Economics Comments at 14–16.

[201] OMS Comments at 3–4.

[202] Industrial Customers Comments at 13.

[203] PJM Comments at 6–7.

[204] DTE Comments at 4.

[205] TAPS Comments at 8.

[206] *Id.* at 11–12.

[207] WATT Comments at 8–9.

[208] WATT Reply Comments at 3.

current transparency provisions are satisfactory and expressed concerns about challenges or litigation upon publication of transmission line rating methodologies.[209] For example, while Exelon does not oppose posting transmission line ratings, it states that the PJM transparency method is sufficient, suggesting that no further transmission line rating transparency requirements is necessary.[210] MISO Transmission Owners do not believe that increased transparency will improve reliability, adding that information on transmission line rating methodologies is already provided through FERC Form No. 715.[211] MISO Transmission Owners contend that transmission line ratings should not be reviewed or challenged by market participants because such parties do not bear reliability obligations and that justifying transmission owner ratings to market participants would be costly.[212] Similarly, while AEP states that it would support any rule that required the publication of transmission line rating methodologies, AEP also suggests it is unnecessary and requests protection from litigation.[213] Finally, NERC states that it does not see a reliability benefit to increasing the transparency of rating methodologies, noting that it ended its own requirements for sharing rating methodologies in 2013,[214] and that it already audits for compliance with the NERC Reliability Standards.[215]

122. Regarding the transparency of ad hoc line transmission line ratings changes specifically, commenters against further transparency include ITC and MISO. ITC contends they should not be posted because change requests may not be granted,[216] and MISO argues that publicly posting ad hoc ratings would be unduly burdensome with no commensurate benefit.[217]

123. Finally, regarding audits, comments were split on whether additional audits are needed. Those that describe the current auditing and review procedures as adequate include NRECA, NERC, ITC, EEI, Exelon, the MISO Transmission Owners, Dominion, and AEP.[218] These commenters largely believe the current transmission line rating review and audit procedures are sufficient,[219] or that new NERC standards are the appropriate path for auditing changes.[220] Conversely, Industrial Customers, Monitoring Analytics, TAPS, DTE, Potomac Economics, and WATT contend that additional oversight would be beneficial.[221] These commenters argue that lax line ratings oversight is pervasive,[222] that transmission providers should review all line ratings,[223] that NERC Reliability Standards are not suitable for auditing,[224] and that the Commission should occasionally audit.[225]

2. Proposal

124. To remedy any potentially unjust and unreasonable rates caused by inaccurate transmission line ratings, we propose, pursuant to section 206 of the FPA, to revise the Commission's regulations to require transmission owners to share transmission line ratings for each period for which transmission line ratings are calculated (with updated ratings shared each time ratings 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.

125. We preliminarily find that this proposal will afford transmission providers and market monitors more operational and situational awareness. Because transmission line ratings and transmission line rating methodologies will be shared only with transmission providers and, in regions served by an RTO/ISO, also with the market monitor(s) of that RTO/ISO rather than with the broader public, we believe that this proposal should address confidentiality concerns as well as litigation risks and compliance burdens.

126. We preliminarily find that this proposal to require transmission owners to share transmission line ratings 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, will enhance operational and situational awareness by ensuring that transmission providers know the effect that changes in ambient temperature would have on transmission line ratings within their system. This information is critical to transmission providers because it allows them to reasonably anticipate increases and decreases in transmission capability and coordinate system operations accordingly. Moreover, we believe that sharing transmission line rating methodologies with transmission providers and, in regions served by an RTO/ISO, also with the market monitor(s) of that RTO/ISO will provide transmission providers and market monitors the information necessary to verify the resulting transmission line ratings and to identify potential errors.

127. We disagree with suggestions that further transparency measures are not needed. To the contrary, the proposed requirement would provide transmission providers and market monitors, where applicable, essential information needed both to validate transmission line ratings and to ensure operational and situational awareness. While current NERC Reliability Standards provide some transparency regarding transmission line ratings and methodologies, current transparency levels may be insufficient to ensure accurate transmission line ratings and, thereby just and reasonable rates. Moreover, while some commenters note that they already provide transmission line rating methodologies pursuant to FERC Form No. 715, Form No. 715 collects information that relates only to transmission line rating methodologies used in long-term transmission planning analyses. By contrast, the proposal would apply to transmission line ratings and methodologies used in near-term transmission service. In addition, while § 37.6 of the Commission's regulations requires all data used to calculate ATC, TTC, TRM, and CBM for congested paths be made publicly available upon request, such data may not necessarily include the transmission line rating methodology and may not be well suited for RTOs/ISOs, which typically make ATC available only at external seams.

128. While we propose to limit the sharing of a transmission owner's transmission line ratings and transmission line rating methodologies

[209] AEP Comments at 5; Dominion Comments at 13; EEI Comments at 11–12; Exelon Comments at 33; MISO Transmission Owners Comments at 18–19.

[210] Exelon Comments at 14–15.

[211] MISO Transmission Owners Reply Comments at 9 (citing FERC Form No. 715, at part IV(D)).

[212] MISO Transmission Owners Comments at 19–20.

[213] AEP Comments at 4–5.

[214] NERC Comments at 4 (citing *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards,* Order No. 788, 145 FERC ¶ 61,147 (2013) (retiring NERC Reliability Standard FAC–008, R4 and R5)).

[215] *Id.* at 5–6.

[216] ITC Comments at 6.

[217] MISO Comments at 8.

[218] NRECA Comments at 7; NERC Comments at 5–6; ITC Comments at 6; EEI Comments at 10–11; Exelon Comments at 17–19; MISO Transmission Owners Comments at 22–25; Dominion Comments at 16; AEP Comments at 4–5.

[219] ITC Comments at 6; EEI Comments at 10–11; Exelon Comments at 17–19; MISO Transmission Owners Comments at 22–25; Dominion Comments at 16; AEP Comments at 4–5.

[220] NRECA Comments at 7.

[221] Industrial Customer Comments at 10–14; Monitoring Analytics Comments at 4–5; TAPS Comments at 12–13; DTE at 6–8; Potomac Economics Comments at 18; WATT Comments at 9.

[222] Industrial Customer Comments at 13–14.

[223] Monitoring Analytics Comments at 4–5; Potomac Economics Comments at 18.

[224] TAPS Comments at 12–13.

[225] WATT Comments at 9.

to only the transmission owner's transmission providers and, in regions served by an RTO/ISO, also to the market monitor(s) of that RTO/ISO, we acknowledge that sharing such information with other interested parties may yield benefits. Sharing transmission line ratings and transmission line rating methodologies with other interested parties allows for 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. For this reason, we seek comment on whether to require transmission owners to share upon request their transmission line ratings and rating methodologies with transmission providers other than the transmission owner's own transmission providers. We also seek comment on whether to require transmission owners to make their transmission line ratings and rating methodologies available to other interested stakeholders, including posting information on their OASIS pages or other password protected online forum.

129. In response to arguments that additional auditing of transmission line ratings to ensure accuracy is needed, while we propose no new auditing requirements, we reiterate that the Commission will continue to conduct reviews of line ratings as a component of broader tariff compliance audits.

VI. Compliance

130. We propose that each public utility transmission provider be required to submit a compliance filing within 60 days of the effective date of any final rule. We note that this compliance deadline would be for public utility 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, and for transmission owners to submit tariff changes implementing the proposed transparency reforms or for each entity to otherwise comply with any final rule. We understand that implementing the reforms required by any final rule in this proceeding may be a complex endeavor. However, we preliminarily find that implementation of these reforms is important to ensure rates are just and reasonable. Therefore, for the AAR reforms, we propose a staggered approach that would prioritize implementation on historically congested lines (within one year from the date of the compliance filing for implementation to any final rule), and propose to require a less aggressive implementation of AARs on all other lines (within two years from the date to the compliance filing for implementation of any final rule). For the DLR reforms, we propose that tariff changes filed in response to a final rule in this proceeding must become effective within one year from the date of the compliance filing for implementation to any final rule. Likewise, for the transparency reforms, we propose that tariff changes filed in response to any final rule in this proceeding must become effective within one year from the date of the compliance filing to any final rule in this proceeding.

131. 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 or are permissible under the independent entity variation standard or regional Reliability Standard. Where these provisions would be modified by this final rule, public utility transmission providers must either comply with this 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 continue to be permissible under the independent entity variation standard or regional Reliability Standard.[226]

132. We seek comment on whether 60 days is sufficient time for public utility transmission providers to develop new tariff language in response to the final rule.

133. To the extent that any public utility transmission provider believes that it already complies with the reforms proposed in this proceeding, the public utility transmission provider would be required to demonstrate how it complies in the compliance filing required 60 days after the effective date of any final rule in this proceeding. To the extent that any public utility transmission provider believes that its existing market rules are consistent with or superior to the reforms adopted in any final rule, the Commission will entertain those at that time.

134. As discussed above, we propose the following compliance timelines for the proposals in this NOPR:

Proposed due date (from the date of the compliance filing to any eventual final rule)	Proposed compliance obligation
1 year	Requirement for Transmission Providers to implement AARs on historically congested transmission lines.
2 years	Requirement for Transmission Providers to implement AARs on all other transmission lines.
1 year	Requirement for RTOs/ISOs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly.
1 year	Requirement for transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in RTOs/ISOs, their respective market monitor(s).

VII. Information Collection Statement

135. The information collection requirements contained in this NOPR are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[227] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[228] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this 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.

136. This NOPR would, pursuant to section 206 of the FPA, reform the *pro forma* Open Access Transmission Tariff (OATT) and the Commission's regulations to improve the accuracy and transparency of transmission line

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

[227] 44 U.S.C. 3507(d).

[228] 5 CFR 1320.11.

ratings used by transmission providers. These provisions would 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).

137. 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).

138. The Commission solicits 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.

139. Please send comments concerning the collections of information and the associated burden estimates to the Office of Information and Regulatory Affairs, Office of Management and Budget, through *www.reginfo.gov/public/do/PRAMain.* Attention: Federal Energy Regulatory Commission Desk Officer. Please identify the OMB Control Numbers 1902–0096 and 1902–0244 in the subject line of your comments. Comments should be sent within 60 days of publication of this notice in the **Federal Register**.

140. Please submit a copy of your comments on the information collections to the Commission via the eFiling link on the Commission's website at *http://www.ferc.gov.* Comments on the information collection that are sent to FERC should refer to RM20–16–000.

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

142. *Action:* Proposed revision of collections of information in accordance with Docket No. RM20–16–000 and request for comments.

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

144. *Respondents:* Transmission owners, transmission service providers, generation owners, and RTOs/ISOs.

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

146. *Necessity of Information:* The proposed reform to the *pro forma* Open Access Transmission Tariff (OATT) and the Commission's regulations, if adopted, would improve the accuracy and transparency of transmission line ratings used by transmission providers. Specifically, the proposal would require: (1) Transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; (2) Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and (3) transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in RTOs/ISOs, with their respective market monitor(s).

147. *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.

148. Our estimates are based on the NERC Compliance Registry as of September 3, 2020, which indicates that 78 transmission service providers,[229] 797 generator owners,[230] and 289 transmission owners are registered within the United States and are subject to this proposed rulemaking.[231] There are also 6 RTOs/ISOs in the United States subject to this proposed rulemaking.

149. *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 the NERC Reliability Standard FAC–008–3, Facility Ratings.[232]

150. The Commission estimates that the NOPR would affect the burden [233] and cost of FERC–516H and FERC–725A as follows:

PROPOSED CHANGES IN NOPR IN DOCKET NO. RM20–16–000

Area of modification A.	Number of respondents B.	Annual estimated number of responses per respondent C.	Annual estimated number of responses (column B × column C) D.	Average burden hours & cost [234] per response E.	Total estimated burden hours & total estimated cost (column D × column E) F.
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 [235] not in RTOs/ISOs [236]).	1	129	1,440 hrs; $120,485	185,760 hrs; $15,542,539.

[229] 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 proposed rulemaking.

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

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

[232] The burden associated with Reliability Standard FAC–008–3, approved by the Commission under section 215 of the FPA, is included in the OMB-approved inventory for FERC–725A. Reliability Standard FAC–008–3 has not been revised in this proceeding however the requirements proposed in this proposed rulemaking under section 206 of the FPA affects the burden for three requirements in Reliability Standard FAC–008–3.

[233] "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.

PROPOSED CHANGES IN NOPR IN DOCKET NO. RM20–16–000—Continued

Area of modification A.	Number of respondents B.	Annual estimated number of responses per respondent C.	Annual estimated number of responses (column B × column C) D.	Average burden hours & cost[234] per response E.	Total estimated burden hours & total estimated cost (column D × column E) F.
Where network transmission service is provided, use hourly AARs to determine curtailment or redispatch of network 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.
Implement software and systems to communicate the required line ratings with relevant parties. (One-Time Burden in Year 1).	78 (TSPs[237])	1	78	320 hrs; $26,774	24,960 hrs; $2,088,403.
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	320 hrs; $26,774	1920 hrs; $160,646.
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.
Compliance Filings (One-Time Burden in Year 2).	289 (TOs)	1	289	160 hrs; $13,387	46,240 hrs; $3,868,901.
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	960 hrs; $80,323	5,760 hrs; $481,939.
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	160 hrs; $13,387	46,240 hrs; $3,868,901.
Net Subtotal for FERC–516H (Year 1).			373	4,800 hrs; $401,616	542,240 hrs; $45,369,221.
Net Subtotal for FERC–516H (Year 2).			289	320 hrs; $26,774	92,480 hrs; $7,737,802.
Net Subtotal for FERC–516H (Ongoing).			289	160 hrs; $13,387	46,240 hrs; $3,868,901.
FERC–725A, Mandatory Reliability Standards for the Bulk-Power System—Reliability Standard FAC–008–3					
Review and update facility ratings methodology, Requirements R2 and R3. (One-Time Burden in Year 1).	369 (TO & GO)[238].	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 (TO & GO)[238].	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.

151. For the purposes of estimating burden in this NOPR, we conservatively

[234] 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.

[235] Transmission Owners. While the proposed AAR reforms apply to transmission providers, we compute an implementation burden based on the number of transmission owners because transmission owners typically calculate

estimate these values based on the maximum number of entities and burden. As discussed elsewhere in this NOPR, some entities may, for example, already use AARs in their existing operations, in which case the actual burden associated with specific proposals associated with the use of AARs would be lower than the estimate. On the other hand, we also acknowledge that changing approaches to facility ratings may require extra testing and training for some entities to ensure reliable operations and gain familiarity with the approach. We estimate that the majority of the additional burden associated with this NOPR occurs in the first year, and that, once established, the ongoing burden will closely approach the existing burden of operating the transmission system. We seek comment on the estimates in the table above and the assumptions described here.

VIII. Environmental Analysis

152. 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.[239] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under § 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.[240]

IX. Regulatory Flexibility Act

153. The Regulatory Flexibility Act of 1980 [241] 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. Under SBA's size standards,[242] 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).[243]

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

155. We estimate that 337 transmission owners and six planning authorities are also affected by the NOPR. 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.

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

157. We estimate that 78 transmission service providers are affected by the NOPR. We estimate again that 68% of these are small entities.

158. We estimate additional one-time costs associated with the NOPR (as shown in the table above) of:

—$93,710 for each RTO/ISO (FERC–516H)
—$134,541 for each transmission owner (FERC–516H)
—$3,347 for each transmission owner (FERC–725A)
—$13,387 for each affected generation owner (FERC–516H)
—$3,347 for each generation owner (FERC–725A)
—$26,774 for each transmission service provider (FERC–516H)

159. Therefore, the estimated additional one-time cost per entity ranges from $16,734 to $137,219.

160. We estimate that the majority of the additional burden associated with this NOPR 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.

161. 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.'' [244] We do not consider the estimated cost to be a significant economic impact. As a result, we certify that the proposals in this NOPR will not have a significant economic impact on a substantial number of small entities.

X. Comment Procedures

162. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due January 22, 2021. Comments must refer to Docket No. RM20–16–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

164. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

165. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

XI. Document Availability

166. 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

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.

[236] Regional Transmission Organizations/Independent System Operators.

[237] Transmission Service Providers.

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

[239] Regulations Implementing National Environmental Policy Act of 1969, Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[240] 18 CFR 380.4(a)(15).

[241] 5 U.S.C. 601–612.

[242] 13 CFR 121.201.

[243] 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.

[244] 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.*

Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

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

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

List of Subjects in 18 CFR Part 35

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

By direction of the Commission.

Issued: November 19, 2020.

Kimberly D. Bose,

Secretary.

In consideration of the foregoing, the Commission is proposing to amend 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 as follows:

■ a. In paragraph (b), revise paragraphs (10) and (11) and add paragraphs (12) and (13);

■ b. In paragraph (c), add paragraph (5); and

■ c. In paragraph (g), revise the paragraph (g) subject heading, paragraph (12) subject heading, and paragraph (12)(i).

The additions and revisions read as follows:

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(b) * * *

(10) *Ambient-adjusted line rating* means a transmission line rating that applies to a time period of not greater than one hour and reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.

(11) *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 irradiance intensity, transmission line tension, or transmission line sag.

(12) *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.

(13) *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) Every public utility that owns, controls, or operates facilities must have on file a joint pool-wide or system-wide open access transmission tariff, which provides for the following to be shared with its transmission provider(s) (and its Market Monitoring Unit(s), if applicable):

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

(ii) Written transmission line rating methodologies used to calculate the transmission line ratings provided under paragraph (c)(5)(i).

* * * * *

(g) *Tariffs and operations of Commission-approved independent system operators and regional transmission organizations—*

* * * * *

(12) *Transmission line ratings. (i)* Each Commission-approved independent system operator or regional transmission organization must 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 independent system operator's or regional transmission organization's Energy Management System through Supervisory Control And Data Acquisition or related systems.

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

Appendix A: List of Short Names/Acronyms of Commenters

Short name/ acronym	Commenter
AEP	American Electric Power Company, Inc.
AWEA	American Wind Energy Association.
CAISO	California Independent System Operator Corporation.
Dominion	Dominion Energy Services, Inc.
DESC	Dominion Energy South Carolina.
DEV	Dominion Energy Virginia.
DTE	DTE Electric Company.
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council.
Entergy	Entergy Services, LLC.
ERCOT	Electric Reliability Council of Texas.
Exelon	Exelon Corporation.
IEEE	The Institute of Electrical and Electronics Engineers.
Industrial Customers	Includes ELCON, the PJM Industrial Customers Coalition, and the Coalition of MISO Transmission Customers.
ITC	International Transmission Company d/b/a ITCTransmission, Michigan Electric Transmission Company, LLC, ITC Midwest LLC, and ITC Great Plains, LLC.
MISO	Midcontinent Independent System Operator, Inc.

Short name/ acronym	Commenter
MISO Transmission Owners.	The MISO Transmission Owners consists 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 ITCTransmission; 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; MontanaDakota 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.
NRECA	National Rural Electric Cooperative Association.
NYISO	New York Independent System Operator, Inc.
ISO–NE	ISO New England Inc.
ITC	ITC Transmission.
OMS	Organization of MISO States.
PJM	PJM Interconnection, L.L.C.
SPP	Southwest Power Pool, Inc.
TAPS	Transmission Access Policy Study Group.
WATT	Working for Advanced Transmission Technologies.

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

Appendix B: *Pro Forma* Open Access Transmission Tariff

ATTACHMENT M

Transmission Line Ratings

General

The Transmission Provider will implement Ambient-Adjusted Ratings and Seasonal 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 line rating methodology and consistent with Good Utility Practice, considering the technical limitations (such as thermal flow limits) on conductors and relevant transmission equipment, 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) 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 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.

(c) Is calculated monthly, if not more frequently, for each season in the future for which Transmission Service can be requested.

(4) ''Near-Term Point-To-Point Transmission Service'' means Point-To-Point Transmission Service which ends not more than ten 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.

(5) ''Historically Congested Transmission Line'' means a transmission line that was congested (*i.e.,* whose Transmission Line Rating was a binding constraint) at any time on or between [insert date five years prior to the effective date of this final rule] and [insert the effective date of this final rule].

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 under the Obligations of the Transmission Provider set forth in this Attachment is necessary to ensure the safety and reliability of the Transmission System, then the Transmission Provider will use such an alternate rating.

Obligations of Transmission Provider

After the relevant dates specified below in the Implementation section of this Attachment, 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 Point-To-Point Transmission Service, (2) responding to requests for information on the availability of potential Near-Term Point-To-Point Transmission Service (including requests for ATC or other information related to potential service), or (3) posting ATC or other information related to Near-Term Point-To-Point Transmission Service to the Transmission Provider's OASIS site.

The Transmission Provider must use AARs as the relevant Transmission Line Ratings when determining the necessity of curtailment or interruption of Point-To-Point Transmission Service (under section 14.7) 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. For determining the necessity of curtailment or interruption of 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 the necessity of curtailment (under section 33) or redispatch (under sections 30.5 and/or 33) of 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 the following 10 days. 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 any Transmission Service not otherwise covered above in this section (including, but not limited to, requests for non-Near-Term Point-To-Point Transmission Service or requests to designate or change the designation of Network Resources or Network Load), and when developing any ATC or other information posted or provided to potential customers related to such services.

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.

Exception: 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, the Transmission Provider may use a Transmission Line Rating for that line that is not an AAR or Seasonal Line Rating. Examples of such a transmission line include (1) a transmission line where the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature, and (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.

Implementation

The Transmission Provider will implement the use of AARs and Seasonal Line Ratings as required in this Attachment in accordance with the following schedule.

Prior to these implementation dates, the requirements above will not apply.

(1) Historically Congested Transmission Lines: Transmission Provider will complete implementation of AARs and Seasonal Line Ratings for Historically Congested Transmission Lines not later than [insert date one year after the date of the compliance filing to the final rule].

(2) Other Transmission Lines: Transmission Provider will complete implementation of AARs and Seasonal Line Ratings for any other transmission lines not later than [insert date two years after the date of the compliance filing to the final rule].

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