UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TRANSMISSION LOADING RELIEF RELIABILITY STANDARD AND CURTAILMENT PRIORITIES	)))	**Docket No. RM10-9-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF INQUIRY

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I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] is pleased to provide these comments in response to the Commission's Notice of Inquiry, issued January 21, 2010, seeking comments on the interplay between Reliability Standard IRO-006-4 (Reliability Coordination – Transmission Loading Relief ("TLR")) and Curtailment Priorities set forth in the Commission's pro forma open access transmission tariff ("OATT").[2] NERC appreciates the Commission's interest in this area, and believes that current industry initiatives are underway to address the concerns previously expressed by the NRG Companies, the Electric Power Supply Association, and Constellation Energy Commodities Group ("Rehearing Parties") in a request for rehearing of Order No. 713-A.[3]

By this filing, NERC provides background related to these issues, a status update regarding current work efforts and a summary of expected future steps related to the NERC TLR

[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, "Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing," 116 FERC ¶ 61,062 (July 20, 2006).
[2] *Transmission Loading Relief Reliability Standard and Curtailment Priorities*, "*Notice of Inquiry*," 130 FERC ¶ 61,033 (2010) ("NOI").
[3] NOI at P 5 (*citing Request for Rehearing and Clarification of the NRG Companies, the Electric Power Supply Association and Constellation Energy Commodities Group*, Docket No. RM08-7-002 (Apr. 20, 2009)).

procedure, IRO-006-4, and the Interchange Distribution Calculator ("IDC"). In addition, NERC responds to the seven questions posed in the Notice of Inquiry.

II. NOTICES AND COMMUNICATIONS

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III. BACKGROUND

A. Regulatory Framework

Through its enactment of the Energy Policy Act of 2005 ("the Act"), Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval.[4] Section 215 of the Federal Power Act provides that all users, owners and operators of the bulk power system in the United States will be subject to Commission approved Reliability Standards.

On July 20, 2006, the Commission certified NERC as the ERO.[5] Pursuant to Section 215 of the Federal Power Act, the ERO was charged with developing mandatory and enforceable Reliability Standards, which are subject to Commission review and approval.[6] Upon approval by the Commission, the Reliability Standards may be enforced by the ERO, subject to Commission oversight, or the Commission can independently enforce these Reliability Standards.[7]

B. <u>Overview of the TLR Procedure and IDC</u>

The TLR procedure has been in existence since 1997, and was developed as a response to increasing demands on the bulk power system due to Open Access and increased market activity fostered by FERC Order No. 888.[8] Initially, the TLR procedure was developed as a response to the increasing demands on the bulk power system because of wholesale wheeling. While utilities were able to manage congestion by curtailing transmission service that was sold on their own systems, it soon became clear that transmission sales often had significant impacts on the transmission systems of third parties, who had not sold transmission rights on their systems. These issues with "parallel flows" were initially limited to causing economic concerns, as the party experiencing congestion could expend its own resources through redispatch to mitigate the

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[4] 16 U.S.C. § 824o.
[5] *Rules Concerning Certification of the Electric Reliability Organization: Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, 71 FR 8662 (2006), FERC Stats. & Regs. ¶ 31,204 (2006), *order on reh'g*, Order No. 672-A, 71 FR 19814 (2006), FERC Stats. & Regs. ¶ 31,212 (2006). ("Order No. 672").
[6] 16 U.S.C. § 824o.
[7] *Id.*
[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 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996).

congestion. However, in some cases, utility resources could be fully depleted without alleviating the congestion, leading to concerns about the reliability of the entire system.

By not having in place a congestion management procedure with a broad view of multiple transmission systems and their associated transmission sales, it was challenging to develop responses to limit exceedances without granting superior transmission rights to entities with transactions scheduled on a "contract path" basis that was different from the actual "physical path" over which energy flowed. More importantly, the lack of a multi-party congestion management procedure created a potential reliability gap in which a local operator on the transmission system might not have access to the resources necessary to reliably operate their transmission system.

In the summer of 1996, such scenarios developed several times within the Southern Company ("Southern") and Tennessee Valley Authority ("TVA") transmission systems. In response, Southern and TVA developed a coordinated line loading relief procedure that took into account multiple utilities. NERC's Security Coordinator Subcommittee, Commercial Practices Working Group, and Operating Committee worked with Southern and TVA to convert their process into one with an Interconnection-wide perspective. As a result, the TLR procedure was developed and subsequently implemented on an interim basis in the summer of 1997. Concurrently, NERC developed the Interim Interchange Distribution Calculator ("iIDC").

On June 5, 1998, NERC filed with the Commission a request for a declaratory order, asking that FERC, among other things, accept NERC's TLR procedures for use in managing Eastern Interconnection flows.[9] On December 16, 1998, the Commission responded in the affirmative, stating that the TLR process was "…generally consistent with or superior to the *pro*

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[9] *North American Electric Reliability Council*, "Petition for Declaratory Order Regarding NERC's Transmission Loading Relief Procedures and Request for Expedited Consideration," Docket No. EL98-52-000 (June 5, 1998).

forma tariff adopted in Order No. 888…" but also that "…further efforts by NERC and industry participants are necessary."[10] Some entities that protested NERC's filing raised the point that the TLR Procedures and iIDC only considered transmission uses associated with Interchange.[11] The Commission concurred, and directed the Eastern Interconnection utilities, working through NERC, to develop interim modifications to the TLR procedure to address the treatment of flows caused by network service and the serving of native load, to be filed with the Commission no later than March 1, 1999.

On March 1, 1999, NERC filed a response to the FERC Order, on behalf of the Eastern Interconnection utilities. In that response, NERC provided an overview of the interim manner in which it would address the treatment of flows caused by network service and the serving of native load. NERC proposed that by using a "Transaction Contribution Factor," Reliability Coordinators could identify the amount of congestion attributed to Network Service and Native Load ("NNL"), and direct Transmission Service Providers to curtail NNL service consistent with its tariff when Firm point-to-point service was being curtailed.

On May 12, 1999, the Commission accepted NERC's interim proposal, and indicated that it was open to further refinements and expansion of the TLR procedures. On May 20, 1999, NERC filed an updated TLR procedure reflecting the interim proposal, which FERC accepted on July 14, 1999.[12] Consistent with FERC Orders,[13] NERC modified the TLR procedure on February 22, 2000, to remove the redispatch provisions from their original location (following

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[10] *North American Electric Reliability Council*, "Order on Petition for Declaratory Order," 85 FERC ¶ 61,353 (1998) ("December 16, 1998 Order").
[11] Interchange generally refers to the transfer of power from one control area, bounded by metering, to another.
[12] *North American Electric Reliability Council*, "Order on Compliance Filing," 88 FERC ¶ 61,046 (1999).
[13] *See, e.g.*, *Mid-Continent Area Power Pool*, "Order Accepting for Filing Proposed Redispatch Service as Modified," 87 FERC ¶ 61,190 (1999). NERC notes that the language in these issuances makes no clear distinction between redispatch to support firm transmission service, and redispatch of non-designated resources to mitigate a constraint.

curtailment of non-firm service, but prior to curtailment of firm service) and to include them instead with the curtailment of firm service.

NERC's iIDC was replaced in 1999, with the IDC, a more robust implementation than the interim version. In 2001, the IDC was upgraded to use a more sophisticated approach to determining the impact of NNL service. This new approach utilized the advances in computing power to more effectively model the impacts of internal generation serving internal load on a constraint. Load forecast data from the System Data eXchange ("SDX"), as well as utility-specified participation factors for each generator that can be used to estimate an economic dispatch, were combined to estimate internal flows. This was a significant improvement over the existing processes, and it offered greater insight into what was occurring within the Control Area boundaries.

In 2003, the IDC was further modified to support the market operations of the PJM Interconnection ("PJM") and the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). Going beyond the NNL provisions implemented previously, the PJM/Midwest ISO approach utilized the same basic concepts, but modified them in several ways to identify "Market Flow." First, the PJM/Midwest ISO approach calculated flows much more frequently, using more current data. Additionally, it identified both firm and non-firm components of internal dispatch based on resource designation. Most recently, the IDC was modified to use a different threshold for identifying the impact of Market Flow, which aligns more closely with the physical capabilities of entities to meet their redispatch obligations.

At this point, the IDC is a tool used by Eastern-Interconnection Reliability Coordinators to help manage congestion and mitigate actual and potential operating limit exceedances. As the industry has identified additional needs, the IDC has been improved and enhanced on a nearcontinuous basis. The IDC is currently provided to the industry as a service through a contract between NERC and Open Access Technology International, Inc. ("OATI"). NERC staff oversees the contract with OATI, while industry stakeholders (as participants in the NERC IDC Working Group) oversee the technical and engineering aspects of the IDC related to its implementation. The North American Energy Standards Board ("NAESB") oversees development of business practices that specify the commercial aspects of the IDC's operation.

C. Development of the NERC TLR Reliability Standard (IRO-006) and the NAESB TLR – Eastern Interconnection Business Practice (WEQ-008)

Prior to 2005, the majority of NERC's TLR procedures were included in NERC Policy 9 Appendix 9C1. This appendix described TLR levels, curtailment order, on- and off-path constraint rules, curtailment formulas, and logging procedures. In 2005, NERC developed the "Version 0" Reliability Standards, which partially incorporated Appendix 9C1 into Reliability Standard IRO-006-0. Three subsequent versions of IRO-006 have included minor, non-substantive changes to the standard.

While the NERC "Version 0" effort was intended to distinguish existing NERC policies that were reliability-based from those with commercial aspects, the nature of some Reliability Standards made it difficult to do so. For example, it was difficult to separate IRO-006 and the associated TLR process into separate standards, as TLR represents the real-time merging of a reliability need (to remove flows from a constrained facility) and a commercial need (to ensure the actions taken to remove those flows are fair and equitable across all market participants).

In order to devote more resources towards splitting reliability and commercial responsibility, NERC Project 2006-08 was developed. Working jointly with NAESB's Wholesale Electric Quadrant Business Practices Subcommittee, NERC developed Reliability

Standard IRO-006-4. Along with its NAESB companion standard, WEQ-008, this version of IRO-006 identified both the reliability and the commercial aspects of the TLR process, but separated them such that the NERC standard no longer addressed the commercial aspects of TLR. While IRO-006-4 still referred to TLR and the levels used to communicate severity, it no longer identified the specific levels of transmission service that were to be curtailed at each of those levels. Rather, the NAESB companion standard WEQ-008 contained that information.

These changes appropriately split the responsibilities associated with implementing the TLR process between NERC and NAESB. Specifically, NERC retained the reliability aspects of the procedure (implementing TLR to mitigate congestion), while NAESB handled the commercial aspects (identifying what transmission service to curtail at what points in the procedure). In order to assist with the transition of information, NERC and NAESB jointly developed a reference manual that would provide operators with a seamless view of the process as a whole, while simultaneously introducing them to the new allocation of responsibility between NERC and NAESB.

At this time, NERC is in the process of developing version 5 of IRO-006, which will further streamline the Reliability Standard and improve its enforceability. As discussed below, NAESB is also developing modifications to WEQ-008, as well as other business practices, to ensure compliance with provisions of the pro-forma tariff.

D. <u>Recent improvements to the IDC through the Enhanced Flow Visualization Initiative, the related NAESB Initiatives, and NERC Change Orders</u>

In August of 2008, three of NERC's stakeholders (PJM, Midwest ISO, and the Southwest Power Pool, Inc. ("SPP")) prepared a Standards Authorization Request ("SAR") related to "Parallel Flow Visualization/Mitigation for [Reliability Coordinators] in Eastern

Interconnection." This SAR proposed the development of a Reliability Standard that would mandate a new calculation method for the IDC to account for internal flows (NNL) similar to the manner in which PJM, Midwest ISO, and SPP calculate their Market Flow. NERC referenced this proposal in its September 11, 2008, compliance filing.[14]

Progress on the proposal has been made since NERC's September 11, 2008 filing, although the path of the project has changed. NERC's TLR Standard Drafting Team reviewed the SAR, and several options for developing a Reliability Standard in support of the request were discussed. Subsequently, PJM, Midwest ISO, and SPP brought their request to the NERC Operating Reliability Subcommittee ("ORS") and the Reliability Coordinator Working Group ("RCWG") for further discussion. Given that the IDC contained a mechanism for calculating NNL, the ORS determined that the changes requested by PJM, Midwest ISO, and SPP were simply an incremental improvement to an existing implementation. Moreover, NERC Reliability Standards do not specify the functions of the IDC. While much of the older Policy 9 Appendix 9C1 specified details regarding the implementation of business and engineering rules that constitute the operation of the IDC, this information is generally no longer included in NERC's Reliability Standards. Therefore, the ORS decided that it would be more appropriate to develop the proposed modifications as a change to the IDC, rather than through the Standards Development Process.

The ORS and RCWG requested that PJM, Midwest ISO, and SPP develop a business case for the change, which was provided with the assistance of the IDC Working Group

[14] *Modifications of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, "Compliance Filing of the North American Electric Reliability Corporation in Response to Paragraph 50 of Order No. 713-Modifications of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards," Docket No. RM08-7-000, at p. 10 (2008).

("IDCWG"). Accordingly, the IDCWG developed Change Order #283,[15] which described the key aspects of the proposal. In general, the proposal described in Change Order #283 attempts to improve the quality of data used in the IDC to calculate the impacts of NNL use on a given constraint. This is accomplished through more frequent updates to data and calculations, as well as the inclusion of more generator specific information than previously utilized.

The NNL calculation in the current IDC relies on the use of several assumptions, in addition to operating data from the SDX. Generator outages in the SDX include units on forced outage and planned maintenance outage, but do not include units not in use due to economic considerations. Lacking the status of these generators, the NNL calculation assumes those units are online, producing impacts on the congested facility, and are subject to potential curtailments during TLR (despite the fact that, in reality, they are not contributing to the constraint). Additionally, units of 20 MW in size or less are not considered during TLR. Because of these assumptions, combined with the fact that unit output is estimated on a proportional basis and based on the reported load forecast and net Interchange, the Balancing Authority's impact is estimated based on data that may vary significantly from reality.

Under the new proposal, generator impacts would primarily be based on per-generator measured output (although some provisions have been made for aggregate reporting to address the case of small generators). Rather than estimating generator output based on load and whether or not units are on outage, the calculation would utilize real-time output and projected next-hour output to calculate NNL. These calculations would occur every fifteen minutes, and would apply

[15] Change Orders are requests for modification to the IDC tool submitted to the IDC Vendor, which are evaluated for estimation of cost and schedule, and then authorized by NERC for development. Funding for these change orders is generally accomplished through NERC's budgeting process, although in the instant case stakeholders that requested the modification may contribute in part or in full toward the costs of implementation.

to all generators of 1 MW in size or greater. The determination of which quantities of generation will be treated as firm and non-firm will be addressed by NAESB.

The IDC vendor, OATI, has evaluated Change Order #283, and funding sources have been identified. NERC began the implementation of this Change Order in February 2010; however, because of the scope of the changes, NERC will utilize an extensive test period of the software changes prior to using the new approach in actual TLR events. NERC expects the new approach to become effective on or before November 2010, based on the current schedule proposed by the IDC vendor, after which the ORS recommends a twelve to eighteen-month parallel operations test period.

While the Change Order will improve the visibility of internal NNL uses of the transmission system, it will not change the manner in which those uses are treated as firm or non-firm. Transmission Service Providers and other industry participants, working through NAESB's consensus-based, ANSI-approved stakeholder processes, are developing the business practices that define how these NNL uses are prioritized and curtailed. NERC is working with NAESB to ensure that the IDC Change Order includes the appropriate configuration capabilities so that once a business practice has been established to define these priorities it will not be difficult to implement. However, despite the joint effort with NAESB, NERC cautions that the changes needed to support the prioritization process being developed may be different than anticipated, and, therefore, may require additional time and funding beyond that described above.

In January 2010, NERC issued an additional Change Order (#310) related to TLR issues. Change Order #310 would allow for transactions sourcing and sinking within a single Balancing Authority to be more accurately modeled, using a unit-specific Generation Shift Factor ("GSF") and an aggregate Balancing Authority Load Shift Factor ("LSF").

Consistent with FERC Order No. 693,[16] NERC's Coordinate Interchange Standard Drafting Team is preparing a draft standard that would require the "tagging" of internal point-to-point transactions, including all grandfathered and non-Order No. 888 transfers. However, unlike Interchange transactions, which assume an effective redispatch through the transfer of generation from one Balancing Authority to another, and reflect this through the use of a GSF-to-GSF comparison, the redispatch associated with the curtailment of an internal transaction may not be accurately represented due to the use of the GSF-to-LSF comparison. Change Order #310 is still being considered for implementation, and additional work remains to evaluate its impact.

E. <u>Responses to Specific Commission Questions</u>

In the NOI, the Commission posed seven specific questions, to which NERC provides the following responses:

> *(a) Whether Reliability Standard IRO-006-4, as implemented by various transmission providers, reliability coordinators and balancing authorities, results in firm service being made subordinate to non-firm service?*

As written, Reliability Standard IRO-006-4 is neutral with regard to firm and non-firm service. NAESB's Business Practice Standard WEQ-008 currently contains the rules for the TLR Procedure, which defines the manner that firm and non-firm service is to be curtailed when implementing Interconnection-wide congestion management in the Eastern-Interconnection. As previously noted, NERC contracts with OATI to make available a tool (the IDC) that implements the rules defined in WEQ-008.

The implementation of the IDC in most cases ensures that firm service is unlikely to be made subordinate to non-firm service; however, there are areas in which the IDC, as currently

[16] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 at P 821 (2007) (Order No. 693).

implemented, is unable to ensure this. NERC believes the three most common cases where the IDC cannot ensure that firm service will not be made subordinate to non-firm service are:

1.) Untagged, non-firm uses of NNL service (such as service of native load from internal, non-designated resources).

2.) Generators of a size less than that recognized by the current IDC model (20 MW), which essentially makes them uncurtailable.

3.) Tagged, non-firm uses of Point-to-Point that source and sink in the same Balancing Authority, where the IDC model has not been modified to account for the resultant null Transaction Distribution Factor. Today, this issue is addressed on a case-by-case basis as directed by the Reliability Coordinator through the creation of “pseudo Balancing Areas” in the IDC model, but there is no global default solution.

A potential fourth case involves granularity issues when evaluating transactions, where the size of a large Balancing Authority may dilute the apparent impact of one or more of its generators on a given constraint, making it difficult to analyze the unit-specific impacts on that constraint — particularly when compared to the calculated impact of a similar transaction from a specific merchant generator hosted within that same Balancing Authority. NERC believes this is a side-effect of the nature of point-to-point service and the manner in which it is analyzed and curtailed. Absent significant changes to transmission service products, NERC does not have a proposal to address this issue at this time.

(b) How do Transmission Providers currently implement OATT sections 13.6 and 14.7? Specifically, discuss whether Transmission Providers rely solely on the Interchange Distribution Calculator in determining which transactions to curtail, or whether they also take into account non-firm transactions internal to the Balancing Authority which are currently not reflected in the Interchange Distribution Calculator.

NERC does not know how all Transmission Providers currently implement OATT sections 13.6 and 14.7. In some cases (*i.e.*, PJM, Midwest ISO, and SPP), specific changes have been made to the IDC to ensure that non-firm transactions within the Balancing Authority are reflected in the IDC and curtailed accordingly. However, this represents only a portion of the Eastern Interconnection. It is our understanding, that some Transmission Providers rely solely on the IDC in determining which transactions to curtail, but NERC also believes that some Transmission Providers take into account non-firm transactions internal to the Balancing Authority, which are not currently reflected in the IDC. Therefore, a single approach has not been implemented throughout the Eastern Interconnection.

(c) If the Interchange Distribution Calculator results in firm service being made subordinate to non-firm service, would including transactions internal to a Balancing Authority help resolve the problem? If so, what parties would be impacted? If there are affected parties, please provide examples of what the impacts on those parties would be.

Modifying the IDC to include transactions internal to a Balancing Authority may in certain cases help resolve the issue of firm service being subordinate to non-firm service. As discussed in NERC's response to question "a," there are three common cases where the IDC cannot ensure that firm service will not be made subordinate to non-firm service. Including transactions internal to the Balancing Authority in the IDC would not address the problem associated with untagged, non-firm uses of NNL service, but IDC Change Order #283, in concert with the

NAESB Parallel Flow Visualization effort, would do so. Change Order #283 will also address the second problem, as it will reduce the minimum generator size threshold to units of 1 MW or greater. Including in the IDC transactions internal to the Balancing Authority would address the third problem (tagged, non-firm uses of Point-to-Point that source and sink in the same Balancing Authority when the IDC model has not been modified to account for the resultant null Transaction Distribution Factor), and IDC Change Order #310 proposes modifications that would make such inclusions easier. At this time, NERC does not have any proposed solutions for the potential fourth case, where the size of a Balancing Authority can make it difficult to analyze its impact on a specific constraint.

> *(d) If the Interchange Distribution Calculator results in firm service being made subordinate to non-firm service, would modifying it to calculate the Transfer Distribution Factors (TDF) for transactions within a Balancing Authority solve the identified issue of firm transactions being curtailed before non-firm transactions within a Balancing Authority?*

As discussed in our response to question "c," the analysis of transactions within a Balancing Authority will only address the third of the three common cases described above (tagged internal transactions using non-firm Point-to-Point service). However, doing so will not provide a complete solution to the issue of firm transactions being curtailed before non-firm transactions within a Balancing Authority.

> *(e) What is the role and responsibility of the transmission provider, reliability coordinator and balancing authority, in the TLR procedures and curtailment?*

With regard to the TLR procedure and curtailment, the Transmission Provider serves two functions. First, the Transmission Provider identifies the appropriate service and priority of that service, so that the service can be correctly curtailed if need be. This is generally accomplished by the Transmission Service Provider ensuring that Interchange information sent to the IDC accurately represents the service sold, such that it can be appropriately prioritized should curtailment be required. Second, the Transmission Provider identifies potential and actual System Operating Limit ("SOL") and Interconnected Reliability Operating Limit ("IROL") exceedances and requests the assistance of the Reliability Coordinator to mitigate each as needed.

The Reliability Coordinator identifies potential and actual IROL exceedances. The Reliability Coordinator also prepares Mitigation Plans (such as implementing TLR and requesting transactions and internal flows to be curtailed) to address potential and actual SOL and IROL exceedances. The Reliability Coordinator does this with the assistance of other Reliability Coordinators as necessary. With regard to reliability issues, the Reliability Coordinator is the highest operating authority. Thus, the Reliability Coordinator has an obligation to assist in these duties, pursuant to NERC Reliability Standard IRO-001-1.

Balancing Authorities are responsible for providing the necessary adjustments to schedules in order to provide the mitigation requested. In general, this is accomplished by curtailing transactions and internal flows as requested by the Reliability Coordinator.

> *(f) As noted above, a Level 5 TLR is called to allow certain firm transactions to continue or to mitigate further operating limit violations and a Level 6 TLR is called to implement emergency procedures. Are commenters aware of Level 5 or Level 6 TLR procedures being called for reasons other than to allow certain other firm transactions to continue or to mitigate any further operating limit violations?*

First, the purpose of TLR Level 5 is to provide congestion relief through the curtailment of all non-firm flows and the partial curtailment of firm flows. In order to ensure fair treatment of all firm service, the TLR process assumes all firm transactions are flowing, including those scheduled to start, and then develops pro-rata curtailments based on those flows. By definition, the pro-rata curtailment process does not allow preferential treatment of specific firm transactions. While it is accurate to say that a TLR Level 5 allows firm transactions to start, it is not necessarily accurate to say, "a Level 5 TLR is called to allow certain firm transactions to continue."

With regard to the question "f," NERC is not aware of any misuses of TLR Levels 5 or 6, but notes that, as the ERO, NERC's focus is largely on whether or not the mitigation of a potential or actual SOL or IROL violation is successful. As such, our ability to identify misuses of TLR Levels 5 and 6 may be somewhat limited. As discussed in FERC's December 16, 1998 Order regarding TLR procedure, Reliability Coordinators act on behalf of Transmission Providers, and are obligated to take actions consistent with FERC regulations related to Open Access. However, NERC does not conduct OATT oversight or enforcement, because it is not a part of NERC's core reliability mission.

This should not imply that NERC condones inappropriate use of TLR procedures. NERC has a TLR investigation procedure in place that was approved by the NERC Operating Committee on July 18, 2002, which requires that all TLR level 5 initiations be investigated. These investigations are conducted to identify the lessons learned, reliability impacts, and ensure general fairness in implementation; however, investigations are not undertaken with the purpose of measuring compliance with open access tariffs. Reliability Coordinators review investigation reports for TLR Level 5 events at quarterly regular meetings. NERC does note that Level 5b TLRs have been rising over the past several years, with over 85 occurring in 2008, as compared with only five in 2002. More than 50% of level three Energy Emergency Alerts issued in 2007 and 2008 were due to TLR 5a or 5b declarations, when firm load interruption was imminent or in progress. While TLRs are more an indicator of congestion on popular paths, they do indicate that the grid is being pushed harder than it was in the past, which raises reliability concerns.[17] Therefore, NERC is continuing to monitor this situation.

(g) If this is an issue, does it occur in non-RTO/ISO regions, within ISO/RTO footprints, or both?

As discussed above, NERC is unaware of any such abuses, and cannot speak to the location of any such potential abuses. However, NERC notes that Reliability Coordinators have authority under NERC Reliability Standards to take the actions required to protect the reliability of the bulk power system. With regard to SOL and IROL exceedances, Reliability Coordinators may take proactive action under NERC Reliability Standards to prevent such exceedances, as well as direct non-economic redispatch or other specific action on a reactive basis to recover from an exceedance and return operations to within system limits. In this case, that wide latitude applies to the ability to choose the appropriate level of TLR to invoke. There are no mandatory NERC reliability criteria that must be met in order to call a particular level of TLR. This is by design for three primary reasons:

1.) To reinforce that a Reliability Coordinator's primary responsibility is to ensure reliability of the bulk power system;

2.) To allow Reliability Coordinators to exercise their own judgment and experience to guide their actions; and

[17] *See* NERC, *Transmission Loading Relief Requests*, http://www.nerc.com/page.php?cid=4|37|257|272 (last visited Mar. 26, 2010).

3.) To encourage Reliability Coordinators to make critical choices, under circumstances where they have a limited amount of time.

As discussed above, to the extent entities misuse TLR Levels 5 or 6, it is unlikely that such misuses would be considered violations of NERC's Reliability Standards. Moreover, NERC's reliability mandate under section 215 of Federal Power Act does not include authority to monitor and enforce such market-based issues.[18]

[18] *See 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 109 (2009).

IV. CONCLUSION

NERC respectfully requests that the Commission consider the comments set forth herein as it determines the need for future actions related to this topic.

Respectfully submitted,

/s/ Willie L. Phillips

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CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 29th day of March, 2010.

/s/ Willie L. Phillips
Willie L. Phillips

Attorney for North American Electric Reliability Corporation