UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Modification of Interchange and Transmission	)	
Loading Relief Reliability Standards; and Electric	)	Docket No. RM08-7-000
Reliability Organization Interpretation of Specific	)	
Requirements of Four Reliability Standards	)	

Comments of the NRG Companies

Pursuant to the Federal Energy Regulatory Commission ("FERC" or "Commission") Notice of Proposed Rulemaking in the captioned proceeding,[1] Louisiana Generating LLC ("LaGen"), Bayou Cove Peaking Power LLC, Big Cajun I Peaking Power LLC, NRG Sterlington Power LLC, and NRG Power Marketing, LLC (collectively "NRG Companies" or "NRG") hereby submit comments with respect to NERC's proposed modification of the Transmission Line Loading Relief ("TLR") procedure and Reliability Standard IRO-006-4.

The TLR rules proposed by NERC do not address several problems with the existing TLR procedures that result in reduced system reliability and curtailments that are not consistent with the requirements of the Commission's

[1] *Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards*, Notice of Proposed Rulemaking, 73 Fed. Reg. 22856 (Apr. 28, 2008), FERC Stats. & Regs. ¶ 32,632 (2008) ("NOPR").

pro forma Open Access Transmission Tariff ("OATT"). NRG requests that the Commission direct NERC to revise its TLR standards to reduce the excessive use of TLRs and require that the Reliability Coordinators:

(1) Accurately calculate TLR curtailment requirements and distribute those curtailments to all firm and nonfirm internal schedules and interchange transactions, including the transmission provider's native load; and

(2) Ensure that nonfirm transactions affecting a transmission constraint are curtailed prior to curtailing firm transmission service.

There have been no significant improvements in the TLR procedures in the ten years since they were first designed. NERC itself has recognized that critical improvements to the TLR process are needed and that the Interchange Distribution Calculator ("IDC"), used by Reliability Coordinators to identify those transactions to be curtailed, must be revised to reflect actual system uses. The Commission cannot find consistent with the statutory requirements of Section 215 or 205 of the Federal Power Act ("FPA")[2] a proposal that clearly is flawed and that contravenes the Commission's own open access requirements on curtailments.

[2] 16 U.S.C. § 842o (Supp. V 2005); 16 U.S.C. § 824d.

I. Communications

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II. Description of the NRG Companies.

The NRG Companies are all wholly-owned subsidiaries of NRG Energy, Inc. The NRG Companies own approximately 2,400 MW of generation in Louisiana which LaGen uses to generate and sell electricity to, among others, eleven rural electric cooperative native load customers in Louisiana. LaGen's customers comprise approximately 2,100 MW of peak load located throughout the Entergy service area and across a significant portion of the geographic area of Louisiana.[3] LaGen is a registered Balancing Authority responsible for serving

[3] The cooperative customers of LaGen include Beauregard Electric Cooperative, Inc., Claiborne Electric Cooperative, Inc., Concordia Electric Cooperative, Inc., Dixie Electric Membership Corporation, Jefferson Davis Electric Cooperative, Inc., Northeast Louisiana Power Cooperative, Inc., Pointe Coupee Electric Membership Corporation, South Louisiana Electric Cooperative Association,
(footnote continued on next page)

the native load needs of its cooperative customers. The LaGen Balancing Authority Area is located entirely within the Entergy Balancing Authority Area and the native load served by LaGen is intermingled with other loads served by Entergy.

A. LaGen's Experience With TLRs.

LaGen has noted a serious increase in TLRs ordered on the Entergy system in the past two years. While Level 5 TLRs used to be relatively rare, today they are a near weekly occurrence and are seriously impacting LaGen's reliability planning and its ability to responsibly meet its native load obligations.

Based on NRG's review of NERC TLR data, in 2007, the Entergy Independent Coordinator of Transmission ("ICT") issued 29 Level 5 TLRs resulting in the curtailment of over 47,000 MW of firm transmission service, with LaGen absorbing almost 7,000 MW of those scheduled curtailments.[4] In the first

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Southwest Louisiana Electric Membership Corporation, Valley Electric Membership Corporation, and Washington-St. Tammany Electric Corp. Inc.

[4] Percentages were calculated from two separate areas of NERC website. Total number of level 5 TLRs across the interconnect are calculated from the data chart off trend data located at following link:

www.nerc.com/pub/sys/all_updl/oc/scs/logs/trends.htm

The number of level 5 TLRs Entergy called were calculated by totaling the number of Level 5 TLRs reported in the NERC TLR logs found here:

(footnote continued on next page)

five months of 2008, the ICT has already issued 17 Level 5 TLRs curtailing more than 42,000 MW of firm transmission service.[5] These Entergy TLRs represent more than 18% of all Level 5 TLRs called throughout the Eastern Interconnection in 2007, and over 21% of the Level 5 TLRs called in the Eastern Interconnection in the first five months of 2008.

Equally alarming is the increase in redispatch of network resources experienced by LaGen in the five months of 2008. These redispatch obligations are in addition to the schedule curtailments ordered by the ICT. Based on NRG's review of 2007 tag data, the ICT directed the redispatch of about 2,933 MW of network resources Entergy wide, and the redispatch of about 74 MW of LaGen's network resources. NRG's review of tag data indicates that through May of this year, however, the ICT has already called for about 16,093 MW of redispatch of network resources, with LaGen contributing about 3,866 MW. Thus, based on this review, the tag data reveals an escalating problem, which has required

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http://www.nerc.com/~filez/Logs/tlrlogs.html

[5] *Id.*

LaGen to redispatch more of its network resources in the first four months of 2008 than the entire Entergy system redispatched in 2007.[6]

Notably, significant reliance on TLRs to manage congestion is not the rule in other Southern regions of the Eastern Interconnection. For example, TLRs are rarely if ever used in the Duke Power Company or Southern Company balancing authority areas.[7] By contrast, the Entergy region makes extensive use of TLRs to manage routine system congestion. These disparate results occur despite the fact that all Reliability Coordinators are applying the same TLR protocols, but other systems are proactive in ensuring that systems are planned and operated to avoid reliance on TLRs.[8]

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[6] By comparison, prior to 2007, Entergy never called more than 9 Level 5 TLRs in a single year. In fact, between 2000 and 2006, Entergy called a total of 25 Level 5 TLRs. *Id*.

[7] A review of the NERC TLR logs available at: http://www.nerc.com/~filez/Logs/tlrlogs.html shows a comparative absence of TLRs filed by the Duke and Southern Company systems.

[8] The issues with TLRs are not a significant problem in the organized markets because those markets use a security-constrained economic dispatch system and other tools to manage congestion. Nevertheless, because of seams issues, the RTOs have similarly recognized the problem and are supportive of such revisions. *See* Presentation of PJM and Midwest ISO at North American Energy Standards Board ("NAESB") Business Practices Subcommittee, June 4, 2008, ("RTO Presentation") included as an Attachment.

III. Background on TLRs and the Commission's Open Access Policies.

The TLR process was designed to implement the curtailment priority rules included in the Commission's *pro forma* OATT in the Eastern Interconnection.[9] Under the OATT, when curtailments are required:

> (1) Nonfirm transmission services must be curtailed before firm transmission services. Nonfirm services are curtailed in the following order:
>
> - (a) nonfirm redirects of point-to-point transmission service,
> - (b) nonfirm point-to-point transmission service (with shorter duration transactions curtailed first), and
> - (c) network customer's and transmission provider's use of resources that are not designated as Network Resources ("Nonfirm Resources"); and
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> (2) Firm point-to-point and network integration transmission service customers have an equal priority with the transmission provider's use of the system to deliver Network Resources to its native load.[10]

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[9] Other mechanisms are used to implement curtailments in the Western Interconnection and the Electric Reliability Council of Texas ("ERCOT"), NOPR at n.29.

[10] OATT §§ 13.6; 14.7. See also Petition of the North American Reliability Corporation for Approval of Proposed Reliability Standard submitted December 21, 2007 ("NERC Petition"), Exhibit D, p. 12 of 53.

When the Commission initially approved TLR procedures in 1998, it identified as a flaw that the TLR procedures applied only to interchange transactions and not to native load or network service.[11] The Commission directed transmission providers in the Eastern Interconnection to modify the TLR procedures to address this flaw and required that Native Network Load ("NNL") service be included in the curtailments issued by the IDC calculator.[12]

However, the reforms made to the IDC calculator in response to the Commission's prior directives did not fulfill the directive and there remain significant numbers of native load transactions that are still not recognized by the IDC calculator. As discussed below, the IDC: (1) is not required to utilize real-time data to calculate internal schedule curtailments; (2) never curtails nonfirm internal schedules (i.e., schedules with the source and sink within the same balancing area) even prior to curtailing firm transmission; and (3) does not include power purchases by a host balancing authority in the NNL curtailment calculations, because NNL is calculated taking into account only those generation facilities owned by the host balancing authority. In areas such as Entergy, where the host balancing authority routinely transacts (both short and

[11] *North American Electric Reliability Council*, 85 FERC ¶ 61,353 at 63,261 (1998).

long-term) with nonaffiliated generators, and designates those resources Network Resources under its OATT, the resulting NNL calculation for the host balancing authority is severely understated.

The NERC proposal indicates that NERC intends to consider improvements to the IDC calculator and other undefined modifications to the basic TLR model in the future.[13] Realistically, however, it will be years before these improvements are even considered, and there is no assurance that NERC will remedy these deficiencies. In fact, there may be significant resistance to change by transmission providers that may benefit from these flaws. An indefinite delay, measured at best in years, to resolve the significant impacts on system reliability caused by the current TLR proposal is clearly unacceptable. Accordingly, NRG requests that the Commission require NERC to implement modifications on an expedited basis that address these flaws in the current TLR procedures that violate the Commission's OATT curtailment requirements and threaten system reliability.

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[12] *Id*.

[13] NERC Petition at 26.

IV. Comments.

NRG does not disagree with NERC's statement of the appropriate standard of review, and, simply put, this filing does not satisfy the legal standard.[14] Notwithstanding the fact that the TLR standards proposed by NERC in this proceeding (and more specifically the flaws therein) are currently in effect, the Commission's acceptance of these standards would elevate these practices by finding them consistent with the FPA standard -- and as such -- NERC must be compelled, on an expedited basis, to fix the flaws that NERC otherwise would reserve for Phase III.[15]

A. The NERC Proposal Does Not Remedy The Reliability Problems Caused By The Current Overuse Of TLRs.

The excessive use of TLRs is reducing system reliability in some non-organized markets and the Commission should require NERC to modify its TLR rules to limit the excessive use of TLRs. Large numbers of TLRs prevent adjoining balancing authorities from effectively managing their systems or planning for emergencies. A balancing authority can analyze the potential

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[14] FPA §215 specifies that all propose reliability standards must be "just, reasonable, not unduly discriminatory or preferential, and in the public interest." 16 U.S.C. §824o(f) (Supp. V 2005).

reliability impacts of a single generation contingency, however TLR impacts are much harder to include in a reliability plan. The excessive use of TLRs as routine congestion management limits the ability of surrounding balancing authority areas to adapt to contingencies. LaGen routinely utilizes firm capacity scheduled on firm transmission from the Entergy system and outlying system to meet its native load obligations. However, the current TLR situation makes it impossible for LaGen to depend on this "firm" capacity.

Further, neighboring balancing authorities have been forced to call Emergency Energy Alert 3 ("EEA3") emergencies resulting from the excessive curtailments issued by the Entergy system over the past 18 months.[16] The excessive use of TLRs also adversely impacts competitive markets by further undermining confidence in firm transmission and the forward market and is largely responsible for a recent reduction in peak hour energy trading liquidity taking place at the Entergy Hub.

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[15] *Id.* FPA §215(f) specifies that the legal standard of review applies to both proposed rules and proposed rule changes.

[16] EEA3 reports are filed when a balancing authority is incapable of satisfying its reserve requirements. An EEA3 Report indicates that a balancing authority was short energy and that a contingency could result in it shedding firm load. *See* http://www.nerc.com/~filez/alertlogs.html

B. Flaws In The IDC Model Relied Upon By The NERC Proposal Result in Improper Allocation Of Reliability Obligations.

The IDC calculator is critical to the TLR process, since Reliability Coordinators rely on the curtailments specified by the IDC. Thus, flaws in the IDC lead to flaws in the curtailments and NNL relief obligations relied upon by Reliability Coordinators to ensure the integrity of the transmission system. LaGen has identified two particularly significant problems with the IDC calculator that the NERC standards proposed in this proceeding do not address:

(1) The generation and load data relied on by the IDC is static, with no requirement that it is regularly updated or accurately reflect real-time conditions; and

(2) The IDC methodology does not curtail certain schedules or determine NNL obligations accurately in some cases, leading to a discriminatory assignment of reliability obligations.

First, there is no requirement in the NERC proposal that the IDC calculator use real-time data to determine reliability obligations. While the IDC uses real-time data in evaluating interchange transactions, it uses static information to model native load uses. Because there is no requirement to update the inputs into the IDC, the data relied upon by the Reliability

Coordinator can be day-ahead, daily, weekly, monthly or seasonal data.[17] If the data is not updated, then the previous day's inputs are simply rolled over and re-used. Accordingly, the IDC calculations which determine flowgate relief are incorrect since they are solving for constraints based on a transmission topology which differs from real-time system topology. The NERC filing includes no standards on how often native load assumptions are updated, such as generation dispatch and load forecasting data.

Second, while the IDC evaluates interchange transactions properly (i.e., transactions where the source and sink are in different balancing authorities), it does not properly reflect internal schedules (i.e., transactions where the source and sink are in the same balancing authority). Calculations made by the IDC ignore internal purchases by a host balancing authority from entities within its footprint, such as sales from an independent power producers ("IPPs") to the host balancing authority.[18] Hence, the impacts on the flowgate are not considered by the IDC even though they could have a significant impact on the constraint. The result is that entities engaging in interchange transactions bear a disproportionate share of the system's reliability obligations.

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[17] RTO Presentation at 14.

For example, a single IPP located in the Entergy balancing authority and simultaneously selling firm power to LaGen and nonfirm power to Entergy could have its firm transmission to LaGen curtailed by the IDC, while the nonfirm transmission purchased by Entergy would remain intact. This is true even if the transactions flowed across the same constrained flowgate because the internal Entergy schedule would not be considered by the IDC.[19] Further, since every transaction in or out of the LaGen system is considered an interchange transactions, the IDC evaluates each LaGen firm transmission transactions for curtailment. Internal purchases by Entergy, however, are not subject to the same rigorous curtailment analysis. Forcing neighboring balancing authorities to bear a disproportionate share of the reliability obligations in a region degrades the ability of that balancing authority to properly respond to potential system emergencies.

In addition, the IDC calculation does not distinguish between firm and nonfirm native load transmission services. As noted *supra*, under the OATT, when the transmission provider or network customer uses nonfirm transmission

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[18] NERC Petition, Exhibit E, p. 16 of 90, §3.11.2.5.

to access nondesignated resources, these uses are assigned a nonfirm curtailment priority and must be curtailed before any firm transactions are curtailed. However, the IDC presumes that all internal NNL transactions are firm and assigns them a firm curtailment priority.

Further, even if the IDC did include all of a host balancing authority's generation transactions, the IDC calculation is biased in favor of geographically large balancing authorities. The bias results from the lack of granularity in the IDC calculator since the calculator evaluates all of the generation and load owned by a host balancing authority – even if the vast majority of the host balancing authority's generation is geographically isolated from the constrained portion of the system. The result is that the IDC calculator assigns all of the relief obligations to smaller balancing authorities, while effectively ignoring the contribution of the larger balancing authority to creating the constraint. The discriminatory assignment of reliability obligations occurs even if the host balancing authority owns the majority of generation and serves most of the load in the constrained region.

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[19] There would be a similar discriminatory impact even if Entergy were also purchasing firm power because these purchases are not picked up in the IDC on either a firm or nonfirm basis.

The Commission should direct NERC to modify the IDC to base its curtailment decisions on accurate native load information and based consistently on local load and generation amounts. Alternatively, as a short term fix, the Commission should direct that NERC identify regions where this inconsistency has the most serious impacts and make adjustments to the IDC calculator to account for these types of internal schedules.

C. All Nonfirm Transactions Should Be Curtailed Before Firm

There is currently a gap in the proposed TLR standards that allows certain nonfirm transactions to escape curtailment prior to the issuance of a Level 5 TLR. This is a clear violation of the Commission's OATT curtailment priority rules and must be remedied.

Under the current TLR procedures, a transaction is curtailed only if its impact on the constrained facilities is shown to have a Transfer Distribution Factor ("TDF") of 5% or more.[20] Accordingly, if the Reliability Coordinator determines that curtailment of nonfirm transactions with a TDF of 5% or more will not fully relieve the constraint, the Reliability Coordinator will initiate

curtailment of firm transactions.[21] By allowing nonfirm transactions with a TDF of less than 5% to continue to flow, the TLR procedures violate the OATT requirement that all contributing nonfirm transactions be curtailed first.

NRG understands that the purpose of the TDF threshold is to focus on those transactions that have the greatest potential for effective relief; however, nonfirm transactions at some level below a 5% TDF threshold (e.g., anything with a TDF above 1%) should be curtailed before curtailing firm transmission service. This will reduce the severity of OATT violations that are inherent in the current TLR procedure. Moreover, this change should be fairly easy to implement since it simply requires a reduction in the threshold used in the IDC.

D. Transmission Owners Should Be Required To Hold Sales Of Additional Transmission Affecting A Path Or Flowgate Experiencing A TLR

Section 2.2.2 of the TLR procedure requires a transmission owner to hold additional interchange transactions, but the hold requirement does not apply to internal schedules (those that do not cross a balancing authority boundary) or to

[21] Of course, as noted in Section IV.B, native load use of nonfirm transmission to reach nondesignated resources will not be curtailed pro rata with other nonfirm uses regardless of the TDF.

transactions having less than a 5% Transfer Distribution Factor ("TDF").[22] By not holding new internal transactions, the amount of load on the affected facilities is increased, further impairing reliability and increasing the exposure of existing customers to additional curtailment. Similarly, by not holding new transactions with a TDF below 5%, the only certainty is that the new transaction will increase the constraint and require further curtailments by existing customers. The Commission should direct NERC to immediately change the TLR procedure to require that all new transactions impacting the constraint be held during the TLR, including internal transactions, such as the transmission provider's use of nonfirm resources, as well as all nonfirm transaction with a TDF below 5%.

V. Conclusion

The flaws identified in the NERC TLR proposal result in a violation of Sections 13.6 and 14.7 of the OATT. The fact that the TLR systems currently in use are flawed does not eliminate the discriminatory impact or the violation of FERC requirements. These violations impact LaGen on a routine basis, increasing its costs and impairing its ability to operate reliably and efficiently.

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[22] Attachment 1-IRO-006, § 2.2. A "hold" means that a transaction that had never started and was submitted after the TLR being declared is not allowed to start. *Id*. at Appendix E.

The Commission cannot allow years to pass to resolve these key flaws. Accordingly, the Commission should direct NERC to address these flaws on an expedited basis and adopt procedures, even if on a temporary basis, which ensure that the transmission provider's nonfirm uses will be curtailed before any firm customer transactions and to ensure that TLRs reflect current information on the then-effective network resource dispatch, including purchased power.

Wherefore, the NRG Companies respectfully request that the Commission consider these comments and provide the clarifications discussed herein.[23]

Respectfully submitted,

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[23] If the Commission determines that it will not require NERC to address these problems systematically on an expedited basis, the Commission should make clear that customers are not precluded from seeking relief from the discriminatory effect of TLR procedures through a case-by-case complaint against a transmission provider's OATT.

ATTACHMENT

Future Path for TLR Proposal

NAESB Business Practices Subcommittee
June 4, 2008
(revised)

pjm

MidwestISO
Energizing the Heartland

History of TLR in Eastern Interconnection

- Primary congestion management procedure used during the past 10 years. Only minor modifications have been made during this time period.
- Where TLR is not the primary congestion management mechanism, it has been used as a reliability backstop when significant, externally induced parallel flows make local procedures insufficient to control facility loading.
- Historically, Reliability Coordinators (RCs) have relied on tag curtailments to curtail non-firm usage and a combination of tags and NNL relief obligations to curtail firm usage (share-the-pain approach).

Three Complaints with the Share-the-Pain Approach

- This approach has resulted in large amounts of tag curtailments for small amounts of relief, it is disruptive to the markets and it has resulted in entities scheduling around bottlenecks.
- The NNL relief obligation is based on a static set of assumptions contained in the IDC. Does not rely on real-time generator, load or net interchange information.
- Because the NNL calculation is based on static assumptions, the RCs lack visualization of the magnitude and the source of parallel flows when they experience congestion.

Recent Enhancements to the TLR Procedure

- With the expansion of the PJM market and the start of the Midwest ISO and SPP markets, the TLR procedure has been enhanced to include market flows on the systems of these entities in place of tags.
- Midwest ISO and PJM have implemented a M2M congestion management process where they use the most cost effective generation in the two markets to meet their combined relief obligations during TLR.

Proposal to Address Complaints

- Congestion management within the TLR procedure in the Eastern Interconnection (EI) would be split into a reliability component managed by NERC and an equity component managed by NAESB.

Reliability Component

- The IDC would indicate the source of all flows on a flowgate and the priority of these flows (tag impacts, gen-to-load impacts and market flow impacts).
- RCs would report their gen-to-load impacts to the IDC on a real-time basis similar to the market flow reporting.
- An RC experiencing congestion would have visualization of the magnitude and source of all flows affecting their flowgate using information from the IDC.
- An RC experiencing congestion would request an amount of flow reduction that would be processed by the IDC. A relief obligation would be issued to all parties contributing to the loading.

Phase I Proposal – Address Reliability Component

- RCs in the EI will report gen-to-load impacts to the IDC similar to Midwest ISO, PJM and SPP.
- There will be an industry-wide criteria developed that explains how the calculation will be made.
- Priority of gen-to-load impacts will fall into one of three categories (Priority 7, 6 or 2).
- All gen-to-load impacts are available for viewing in the IDC.
- The IDC will use tag impacts, market flow impacts and gen-to-load impacts to assign relief obligations on a proportional basis during TLR.

Phase I Proposal – Address Reliability Component (cont.)

- There will be monitoring for compliance in achieving the assigned relief obligations.
- This Phase I implementation will require infrastructure and IDC enhancements.
- This Phase I implementation should still be considered a share the pain approach since tag cuts will be done on a proportional basis with market flows and gen-to-load cuts.
- This Phase I implementation does not require tariff changes and would only require minor edits to the NERC TLR standard and NAESB business practices.
- This Phase I implementation will need detailed procedures on the gen-to-load impact calculation, determination of coordinated flowgates, enhancements to the IDC and communication protocols with the IDC.

Equity Component

- The parties with an assigned relief obligation would rely on business practices and procedures in their tariffs to meet the relief obligation.
- If a party with an assigned relief obligation has both redispatch and tag curtailments available to them, they could use either method or a combination of both methods to meet their relief obligation.
- Equity issues on how the relief obligation will be accomplished in the most cost effective manner should be addressed in the filed tariffs with FERC.
- All parties would be encouraged to expand their tools to meet their relief obligations. NAESB would lead the effort to identify methods available to meet relief obligations and to include these methods in the filed tariffs.

Summary of Future Path for TLR Proposal

- Provides RCs with visualization of the magnitude and source of all flows they experience. These flows are used in the assignment of relief obligations.
- Allows the parties responsible for meeting relief obligations to do so using FERC filed business practices and procedures. To the extent there are equity issues, FERC is the proper forum to address.
- The IDC would be expanded to accept gen-to-load impacts reported by RCs similar to the market flows reported by Midwest ISO, PJM and SPP.
- The IDC would be used to assign relief obligations based on tag impacts, market flow impacts and gen-to-load impacts.

Seek Industry Support for Future Path for TLR

- Line item included in NAESB 2008 Annual Plan. Midwest ISO and PJM will work with both NERC and NAESB to address reliability component and equity component.
- The initial focus will be to move forward with the Phase I proposal to address the reliability component. Midwest ISO and PJM developed a draft SAR that contains a Phase I proposal. Seeking input on this Phase I proposal before submitting the SAR for public comment.
- A detailed description of the Phase I proposal was given at the May 7 NERC ORS meeting.

NERC ORS Reaction to Phase I Proposal

- Some RC's are not impacted by parallel flows and question whether there are loading problems in the EI due to parallel flows.
- Some RC's are unaware of the use of static data in the IDC and how this impacts the NNL calculation.
- Some RC's do not use TLR and question the benefits they will receive by having an expanded IDC.
- To obtain RC support will require developing a business case that supports the need for visualization of parallel flows in the EI and that supports the need to use real-time data in the NNL calculation.

Instances of High Parallel Flows in the EI

- Midwest ISO/PJM Loop Flow Study issued May 2007 documents times prior to 2007 when high circulation flows have existed around Lake Erie.
- An updated Midwest ISO/PJM Loop Flow Study is now underway that is documenting parallel flows that occurred in 2007.
  - On June 12, 2007 a combination of transmission contingencies and generator contingencies plus high Lake Erie circulation contributed to IESO initiating its voltage reduction procedures.
  - On August 19, 2007 PJM initiated TLR 5b on its interface with Duke to manage congestion caused by a N. to S. bias (mild temp in NE vs. hot temp in SE).
  - On August 20, 2007 PJM initiated TLR 5a on its interface with CPL to manage congestion caused by a N. to S. bias (mild temp in NE vs. hot temp in SE).
  - On December 3-6, 2007 PJM initiated TLR 3a/3b on its interface with CPL to manage congestion caused by a S. to N. bias (mild temp in SE vs. cold temp in NE).

Static Assumptions Used by IDC in NNL Calculation

- The NNL calculation relies heavily on operating information submitted to the SDX to model system conditions. However, there is no requirement that operating information be submitted to the SDX.
- There is no real-time load used in NNL calculation. Relies on forecasted load data submitted by BA to SDX. If BA does not submit hourly or daily peak load data, uses seasonal load for NNL calculation.
- All generators not on outage in the SDX are assumed to be on-line and serving load. All units are scaled in proportion to their PMAX in order to match generation and load. The RC can manually remove units from the NNL calculation. However, this is a tedious process that delays calling TLR5.

Static Assumptions Used in NNL Calculation (cont.)

- Where SDX has a negative net interchange for the BA (net importer), the BA load is reduced by the amount of import before generation is dispatched.
- Transmission system topology used in the NNL calculation is based on the reported outages in the SDX.
- Unlike tag impacts and market flow impacts that can be viewed in the IDC, there are no gen-to-load impacts that can be viewed in the IDC.
  - The NNL calculation is made on an on-demand basis prior to calling TLR5. RCs have the opportunity to adjust some of the static data (this is tedious work and would only be done to improve the NNL relief obligation). This means there is no parallel flow information to review in real-time and no parallel flow information to store in an archive for after the fact reviews.

IDC Provides Limited Flexibility in NNL Calculation

- If a unit has been split between two BAs (i.e. a JOU that has been pseudo-tied), can apply a percent ownership that will result in separate dispatches and separate NNL calculation for the two BAs.
- If a portion of the unit output has been dedicated to a transaction that has been tagged, can remove it from the NNL calculation.
- An RC can remove a unit from the input data and rerun the NNL calculation before issuing the TLR5. However, the SDX files must be updated prior to the next file upload to reflect this change in status (NNL calculation reverts back to the SDX status after the next SDX upload).

IDC Problems in NNL Calculation (Beyond the Use of Static Data)

- Even though loads are reported on a BA level, many of these reported loads are from the entity that has BA responsibility and may not be the total load in the BA.
- There is a 20 MW minimum limit on generator buses that have an NNL calculation made.
- There is no special treatment of non-designated resources. Assumes all generators have firm use of the transmission system on all flowgates. There is no assignment of gen-to-load to non-firm usage of the transmission system.
- Not aware of any process that holds gen-to-load impacts during TLR. Not aware of any steps taken to verify BA NNL relief obligations have been met.
- Calculation of how a BA should meet its NNL relief obligation is a manual process that consumes RC time. CO254 provides limited improvement to manual process.

Recommend a Tag Archive be Created in the IDC

- Midwest ISO and PJM made a recommendation in the May 2007 Loop Flow Study that a tag archive be created that would store tag impacts, market flow impacts and gen-to-load impacts on a flowgate-by-flowgate basis for after the fact analysis.
- IDC currently archives all tags but without knowing system topology, it is nearly impossible to determine flowgate impacts.
- Midwest ISO and PJM are following-up on this earlier recommendation by including it in the Future Path for TLR Proposal.

Next Steps for Future Path for TLR Proposal

- Midwest ISO and PJM will schedule a call with the NERC RCWG to seek RC support for the Phase I proposal.
- Midwest ISO and PJM will schedule a meeting with FERC Staff to discuss parallel flows in EI and how this Phase I proposal would address parallel flows. This is follow-up to September 2007 meeting where Phase I Loop Flow Study was reviewed with FERC Staff.
- Midwest ISO and PJM are seeking CMP Council support for SAR prior to submitting it at NERC.
- Midwest ISO and PJM are seeking support from their stakeholders to endorse the SAR after it has been submitted at NERC.

Future Path for TLR Proposal

- Questions?

CERTIFICATE OF SERVICE

I hereby certify that the foregoing document has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 12th day of June 2008.

/s/*Michael J. Rustum*
Michael J. Rustum