When completed, e-mail to: mark.ladrow@nerc.net

Standard Authorization Request Form

Title of Proposed Standard	Modification to IRO-006-1 to allow Market Flow Information as input to IDC
Request Date	12/15/05

SAR Requestor Information	**SAR Type** (Check box for one of these selections.)	
Name Lanny Nickell	☐	New Standard
Primary Contact same	☒	Revision to existing Standard
Telephone 501.614.3232 Fax	☐	Withdrawal of existing Standard
E-mail lnickell@spp.org	☐	Urgent Action

Purpose (Describe the purpose of the proposed standard — what the standard will achieve in support of reliability.)

Industry Need (**Provide** a detailed statement justifying the need for the proposed standard, along with any supporting documentation.)

SPP is requesting a modification to the NERC Transmission Loading Relief (TLR) procedure to expand the scope of values accepted by the Interchange Distribution Calculator (IDC) to include Market Flows. Market Flows represent the impacts on flowgates of energy dispatched in a market, such as that operated by a Regional Transmission Organization or Independent System Operator, that are not tagged as an interchange transactions. Allowing Market Flow impacts to be represented in the IDC allows markets to participate in the Eastern Interconnection transmission loading relief method on a basis equivalent to that of tagged interchange transactions. The reliability benefit is that these market resources then are able to participate in the reduction of flows on a specified flowgate during a transmission loading relief event. The proposed change is similar to and replaces the regional differences that currently exist for MISO and PJM. The proposed revision to the standard has been endorsed by the NERC Operating Reliability Subcommittee. The proposed revision, if approved, will replace the waivers for PJM and MISO that were carried over in the Version 0 standards. The changes to the standard will be applicable to any market entity and will therefore remove the presence of a regional difference from the standard.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☒	Reliability Coordinator	Ensures the reliability of the bulk transmission system within its reliability coordinator area.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within its metered boundary and supports system frequency in real time
☐	Interchange Authority	Authorizes valid and balanced Interchange Schedules
☐	Planning Authority	Plans the bulk electric system
☐	Resource Planner	Develops a long-term (>1year) plan for the resource adequacy of specific loads within a Planning Authority area.
☐	Transmission Planner	Develops a long-term (>1 year) plan for the reliability of transmission systems within its portion of the Planning Authority area.
☐	Transmission Service Provider	Provides transmission services to qualified market participants under applicable transmission service agreements
☐	Transmission Owner	Owns transmission facilities
☐	Transmission Operator	Operates and maintains the transmission facilities, and executes switching orders
☐	Distribution Provider	Provides and operates the “wires” between the transmission system and the customer
☐	Generator Owner	Owns and maintains generation unit(s)
☐	Generator Operator	Operates generation unit(s) and performs the functions of supplying energy and Interconnected Operations Services
☐	Purchasing-Selling Entity	The function of purchasing or selling energy, capacity and all necessary Interconnected Operations Services as required
☐	Market Operator	Integrates energy, capacity, balancing, and transmission resources to achieve an economic, reliability-constrained dispatch.
☐	Load-Serving Entity	Secures energy and transmission (and related generation services) to serve the end user

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☐	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
☐	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*	
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes	
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes	
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes	
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes	
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes	

Detailed Description (Provide enough detail so that an independent entity familiar with the industry could draft a Standard based on this description.)

NNL Calculations

Attachment 1-IRO-006-1, Section 5 (Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service)

Section 5 of Attachment 1-IRO-006-1 currently requires that the "Per Generator Method Without Counter Flow" methodology be utilized to calculate the portion of parallel flows on any Constrained Facility due to Network Integration (NI) transmission service and service to Native Load (NL) of each control area.

SPP intends to use a "Market Flow Calculation" methodology to calculate the portion of parallel flows on all facilities included in the RTO's "Coordinated Flowgate List" due to NI service or service to NL of each control area.

Pro Rata Curtailment of Non-Firm Market Flow Impacts

Attachment 1-IRO-006-001, Appendix B (Transaction Curtailment Formula)

Appendix B (Transaction Curtailment Formula) details the formula used to apply a weighted impact to each non-firm tagged transaction (Priorities 1 thru 6) for the purposes of curtailment by the IDC. For the purpose of curtailment, the non-firm market flow impacts (Priorities 2 and 6) submitted to the IDC by the RTO should be curtailed pro-rata as is done for INTERCHANGE TRANSACTIONS using firm transmission service. This is because several of the values needed to assign a weighted impact using the process listed in Appendix B will not be available:

- Distribution Factor (no tag to calculate this value from)
- Impact on Interface value (cannot be calculated without Distribution Factor)
- Impact Weighting Factor (cannot be calculated without Distribution Factor)
- Weighted Maximum Interface Reduction (cannot be calculated without Distribution Factor)
- Interface Reduction (cannot be calculated without Distribution Factor)
- Transaction Reduction (cannot be calculated without Distribution Factor)

While the non-firm market flow impacts submitted to the IDC would be curtailed pro rata under this proposal, the impacting non-firm tagged transactions could still use the existing processes to assign the weighted impact value.

Assignment of Sub-Priorities

- Attachment 1-IRO-006-1, Appendix E (How the IDC Handles Reallocation), Section E2 (Timing Requirements)

Under the header "IDC Calculations and Reporting" in Section E2 of Appendix E

to Attachment 1-IRO-006-001, the following requirement exists:

"In a TLR Level 3a the INTERCHANGE TRANSACTIONS using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities.

SPP intends to use a "Market Flow Calculation" methodology to calculate the amount of energy flowing across all facilities included in the RTO's "Coordinated Flowgate List" that is associated with the operation of the RTO market. This energy is identified as "market flow".

These market flow impacts for current hour and next hour will be separated into their appropriate priorities and provided to the IDC by SPP. The market flows will then be represented and made available for curtailment under the appropriate TLR Levels.

Even though these market flow impacts (separated into appropriate priorities) will not be represented by conventional "tags", the impacts and their desired levels will still be provided to the IDC for current hour and next hour. Therefore, SPP proposes that for the purposes of reallocation, a sub-priority (S1 thru S3) be assigned to these market flow impacts by the NERC IDC as follows, using comparable logic as would be used if the impacts were in fact tagged transactions. Since SPP market flow is always present, sub-priority 4 is not applicable.

ADDITIONAL DETAIL is INCLUDED in ATTACHED DOCUMENT

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation
None Assigned	A TLR Modifications SAR is currently being developed in parallel by a joint NERC and NAESB committee. Their efforts are aimed at both updating the procedure and then subdividing the standard into reliability requirements and business practices. Modifications need to be coordinated, but the modifications needed to implement the SPP market changes need to be accomplished by May 1, 2006 to meet the schedule submitted to FERC.

Regional Differences

Region	Explanation
ECAR	
ERCOT	
FRCC	
MAAC	
MAIN	
MAPP	
NPCC	
SERC	
SPP	
WECC	