NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Modifications to Coordinate Interchange Standards for Applicability and General Upgrade
Request Date	May 27, 2008
Modified Date	December 1, 2008

SAR Requester Information	**SAR Type** (*Check a box for each one that applies.*)	
Name Interchange Subcommittee	☐	New Standard
Primary Contact Don Lacen, IS Chair	☒	Revision to existing Standards INT-001-2 — Interchange Transaction Tagging INT-003-2 — Interchange Transaction Implementation INT-004-1 — Interchange Transaction Modifications INT-005-2 — Interchange Authority Distributes Arranged Interchange INT-006-2 — Response to Interchange Authority INT-007-1 — Interchange Confirmation INT-008-2 — Interchange Authority Distributes Status INT-009-1 — Implementation of Interchange INT-010-1 — Interchange Coordination Exemptions
Telephone 505-241-2032 Fax 505-241-2582	☐	Withdrawal of existing Standard
E-maildon.lacen@pnm.com	☐	Urgent Action

Purpose **(Describe the proposed standard action: Nomination of a proposed standard, revision to a standard, or withdrawal of a standard and describe what the standard action will achieve.)** Revise the set of Coordinate Interchange standards to ensure that each requirement is assigned to an owner, operator or user of the bulk power system, and not to a tool used to coordinate interchange; to address the Interchange Subcommittee concerns related to the Dynamic Transfers and Pseudo-ties; to address previously identified stakeholder comments

and applicable directives from Order 693; to define communications on reloading interchange transactions due to different operational conditions; and to bring the set of Coordinate Interchange standards into conformance with the latest versions of the Reliability Standards Development Procedure, ERO Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

There is confusion regarding the Interchange Authority "function". The need for improved clarity became apparent when entities were recently asked to register in the Compliance Registry as "Interchange Authorities" and entities had difficulty determining which entities were performing the Interchange Authority tasks identified in the set of Coordinate Interchange standards. The Interchange Authority activities in the Coordinate Interchange standards are performed by software systems and not a responsible entity. The software, not a functional entity, performs the task of accepting and disseminating interchange data between entities.

The Coordinate Interchange standards dealing with the Interchange Authority and the current Functional Model representations of the Interchange Authority do not reflect technological advances made since the Functional Model working group originally defined the Interchange authority and advances made since the Coordinate Interchange standards were written.

There are different interpretations surrounding the requirements associated with Dynamic Transfers and Pseudo-ties. Adding definitions for the terms used to reference Dynamic Transfers and Pseudo-ties (e.g., Dynamic Schedule, Dynamic Transfer, Pseudo-tie, Dynamic Schedule Curtailment) will add clarity to these requirements.

Additional requirements may be needed to address the principles outlined in the Interchange Subcommittee's Principles and Definitions Supporting Dynamic Transfers and Pseudo-ties. (Attachment 2)

Review the current NERC Glossary of Terms related to interchange to determine if any revisions or new definitions are necessary as a result of the Interchange standards development.

The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or subsequent phase(s) of the project.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

The modifications in the set of Coordinate Interchange Standards should address the following:

- Determine if the activities in the Coordinate Interchange standards correctly identify the responsible entity.
- Consider requiring each Sink Balancing Authority or its designee to be responsible for providing the Interchange Authority functions using an interchange transaction tool process as defined in the latest approved version of the e-Tag

Specifications.

- The existing requirements are tool-neutral. Consider adding specific references to the e-Tagging process, applications, and tools in the requirements
- Consider adding a requirement to have backup capability for use when the interchange transaction tool fails.
- Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.
- Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)
- Determine if there is industry-wide support for the Interchange Subcommittee's Principles and definition supporting dynamic transfers and pseudo-ties, and if there is support, modify the requirements and add definitions accordingly.
- If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

The work in this project should be done in two or more phases, with the first phase focused solely on clarifying the applicability of each requirement in the existing set of standards. All other revisions should take place in a second or subsequent phase(s).

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

Revise the following set of Coordinate Interchange Standards so that the responsibility for each of the requirements is clearly assigned to an owner, operator or user of the bulk power system, and not to a tool.

INT-001-2 — Interchange Transaction Tagging
INT-003-2 — Interchange Transaction Implementation
INT-004-1 — Interchange Transaction Modifications
INT-005-2 — Interchange Authority Distributes Arranged Interchange
INT-006-2 — Response to Interchange Authority
INT-007-1 — Interchange Confirmation
INT-008-2 — Interchange Authority Distributes Status
INT-009-1 — Implementation of Interchange
INT-010-1 — Interchange Coordination Exemptions

Consider combining requirements into a fewer number of standards so that the resultant set of requirements follows a chronological sequence that is easier to follow.

Address the directives issued by FERC in Order 693, and the stakeholder comments from the V0 drafting team and the Violation Risk Factor drafting team. (See Attachment 1)

Address the principles and definitions proposed by the Interchange Subcommittee in support of dynamic transfers and pseudo-ties. (See Attachment 2)

Make other changes to the standards to bring them into conformance with the latest version of the Reliability Standards Development Procedure, Sanctions Guidelines and Uniform Compliance Monitoring and Enforcement Program.

If there are no tasks assigned to the Interchange Authority function, then make conforming changes to the CIP-002-1 through CIP-009-1 standards by removing the Interchange Authority as an applicable responsible entity.
The work in this project should be addressed in at least two phases with a ballot conducted at the end of each phase. The first phase is needed as soon as possible and should focus on the revisions needed to ensure that each requirement is assigned to a user, owner or operator of the bulk power system. All other proposed revisions should be addressed in the second or later phases of the project.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☒	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☒	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power 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 power 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 power 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 power 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 power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability 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

Related Standards

Standard No.	Explanation
CIP-002-1 through CIP-009-1	If the industry determines that the IA Function is not an “owner, operator or user” of the BES, then the applicability section of these standards should be modified to remove the IA as a responsible entity.

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1

(Issues originally intended for Project 2009-03 – Interchange Information)

INT-001-2 Interchange Information

Directives from FERC Order 693

– Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and “non-Order No. 888” transfers.

– Consider Santa Clara’s comments about the applicability of the LSE in the standard as part of the standards development process.

V0 Industry Comments

– R1 - Too stringent
– R1 – Who tags dynamic schedules?
– Load PSE responsibility is new restriction
– Clarify tagging of reserves
– R2.2 – 60 minute time frame questioned
– Question on generation scheduling
– Onerous to BA’s
– More commercial problem than reliability
– Lack of compliance

VRF Comments

– R1, 1.1, 2, 2.1, 2.2 – commercial and administrative

INT-003-2 Interchange Transaction Implementation

Unresolved Directives from FERC Order 693 – none

VRF Comments

– R1, 1.1, 1.1.2, 1.2 – commercial and administrative

INT-004-1 Dynamic Interchange Transaction Modifications

Unresolved Directives from FERC Order 693 – none

V0 Industry Comments

– Replace TSP with TOP
– Need to address tag curtailment
– Suggested non-compliance levels
– Non-compliance based on %
– Use WECC criteria

VRF Comments

– R2, 2.2, 2.3 – commercial and administrative

INT-005-2 Interchange Authority Distributes Arranged Interchange

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R5 – administrative

INT-006-2 Response to Interchange Authority

Directives from FERC Order 693

- Include reliability coordinators and transmission operators as applicable entities.
- Require reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities' necessary transaction modifications before implementation.
- Consider the suggestions made by EEI and TVA and address questions raised by Entergy and Northern Indiana as part of the standard development process.

INT-007-1 Interchange Confirmation

Unresolved Directives from FERC Order 693 – none

VRF Comment

- R1, 1.1, 1.3, 1.3.1, 1.3.2, 1.3.3, 1.3.4, 1.4 – administrative

INT-008-2 Interchange Authority Distributes Status

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

VRF Comments

- R1.1.1 & 1.1.2 – commercial and administrative

INT-009-1 Implementation of Interchange

Directives from FERC Order 693

- Consider APPA's suggestion to clarify what reliability entity the standard applies as part of the standard development process.

INT-010-1 Interchange Coordination Exemptions

Directives from FERC Order 693

- Consider Northern Indiana's and ISO-NE's suggestions in the standards development process.

VRF Comments

- R1 & 3 – administrative

Attachment 2 – Interchange Subcommittee's Principles and Definitions for Dynamic Schedules and Pseudo-ties

Dynamic Schedules

A dynamic schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between balancing areas. A dynamic schedule must not change a balancing area's jurisdiction; that is, the native balancing area continues to exercise operational jurisdiction over, and provides basic balancing area services to, the dynamically scheduled resources.

All dynamic schedules used to assign the control of generation, loads, or resources from one balancing area to another must meet the following requirements:

1. Telemetry

1.1. Appropriate telemetry for a dynamic schedule must be in place and incorporated by all affected balancing areas. Standards requirements associated with this should address appropriateness issues related to accuracy, sampling rate, etc. which would impact reliability. For example, the relationship of BAL-005-1 R10 and BAL-005-1, R16 should be confirmed.

2. Transmission Service

2.1. Prior to implementation of the dynamic schedule of load or generation, it is the obligation of each involved balancing area to ensure that the dynamic schedule is implemented such that the tariff requirements of the applicable transmission provider(s) are met, including applicable ancillary services and provision of losses.

2.2. If transmission service between the source and sink balancing areas is curtailed then the allowable range of the magnitude of the schedules between them, including dynamic schedules, must be curtailed accordingly. Since dynamic schedules are implemented in ACE via telemetry, curtailment of e-Tags associated with dynamic schedules must be complemented with appropriate adjustments to the telemetered values used in ACE to make the curtailment be physically implemented via ACE control action.

3. System Modeling

3.1. Each balancing area must ensure that the dynamic transfer of load or generation through a dynamic schedule is coordinated with the Reliability Coordinator(s) with responsibility over the native, attaining, and contract intermediary balancing areas so that the dynamic schedule can be properly implemented in the system modeling of the affected generation or load, and necessary data provision requirements are met. Coordination must include tagging of the resultant scheduled interchange for use by other transmission providers and balancing areas for system security analysis and calculation of ATC.

3.2. When a dynamic schedule is used to serve load within another balancing area, the balancing area where the load is electrically connected (native balancing area) must include that load in its balancing area load forecast and any subsequent reporting as needed. This is necessary because the system models must adequately capture the projected demand on the system (load forecast), and the projected supply (provided by the electronic tagging system).

4. Dynamic Schedule Coordination and Scheduling

4.1. Although implemented in the ACE via telemetry, implementation of a dynamic schedule for NERC-identified reliability analysis services must be through the use of an interchange transaction between balancing areas. As such, all dynamic schedules must be tagged and implemented in accordance with NERC Standards.

4.2. Energy exchanged between the source, sink, and intermediary balancing areas as a dynamic schedule is the metered or calculated (obtained by the integration of the dynamic schedule signal over the operating hour) energy for the loads and/or resources for the hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.
4.3. The native balancing area must ensure that agreements are in place defining the responsibility for providing applicable ancillary/interconnected operations services.
4.4. The drafting team should consider reliability impacts and draft appropriate standards related to how dynamic schedules are modeled from various perspectives such as level of detail (i.e. degree to which composite representation is allowed such as each generator having dynamic schedule or allowing a composite plant dynamic schedule) and use of block schedules to serve part of a dynamic schedule. In the latter case, although a single telemetered value may be used in the ACE for a load, it can be represented in the e-Tagging by a combination of one or more block schedules for part of the load and a dynamic schedule for the remainder to represent the dynamic nature of a load.

5. Trouble Response
5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the dynamic schedule on a plan for how the balancing areas will operate during a loss of the dynamic schedule telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.
5.2. The native balancing area, attaining balancing area and intermediary balancing areas shall agree before implementation of the dynamic schedule upon a plan for how the load will be served during abnormal system conditions including periods of time when the transfer path between them is unavailable. The native balancing area, attaining control area and intermediary balancing areas shall also agree before implementation of the dynamic schedule as to how the generation serving the dynamic schedule will respond during abnormal system conditions, including periods of time when the transfer path between them is unavailable.

Pseudo-Ties
Pseudo-ties are often employed to assign generators, loads, or both from the balancing area to which they are physically connected into a balancing area that has effective operational control of them. Thus, pseudo-ties provide for change of balancing area jurisdiction from the native to the attaining balancing area and at the same time make the attaining balancing area provider of balancing area services. This methodology is also referred to as “AGC Interchange” or “Non-Contiguous Pool Tie.” In practice, pseudo-ties may be implemented based upon metered or calculated values. All balancing areas involved account for the power exchange and associated transmission losses as actual interchange between the balancing areas, both in their ACE equations and throughout all of their energy accounting processes.

All pseudo-ties used to assign generation, loads, or resources from the native balancing area to the attaining balancing area must meet the following requirements:
1. Telemetry
1.1. Appropriate telemetry must be in place and incorporated by all affected balancing areas.

2. Transmission Service
2.1. Prior to implementation of the dynamic transfer of load or generation by pseudo-tie, each involved balancing area shall ensure that the pseudo-tie is implemented such that the

tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.

2.2. If transmission service between the native and attaining balancing areas is curtailed, then the allowable range of the magnitude of the pseudo-ties between them must be limited accordingly to these constraints. Since pseudo-ties are implemented in ACE via telemetry, appropriate adjustments must be made to the telemetered values used in ACE to make a curtailment be physically implemented via ACE control action.

2.3. Pseudo-ties must be implemented on firm transmission and are subject to curtailment on a pro rata basis with other firm transactions.

3. System Modeling

3.1. The assignment of load or generation into the control response of another balancing area must be appropriately captured in the IDC and security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators. It is the obligation of each balancing area to ensure that the dynamic transfer of load or generation by pseudo-ties is coordinated with the Reliability Coordinator(s) that have responsibility over the native, attaining, and contract intermediary balancing areas so that the pseudo-tie can be properly implemented in the system modeling of the generation or load affected, and necessary data provision requirements are met.

3.2. The attaining balancing area dynamically transferring load into its effective boundaries through a pseudo-tie shall ensure that load forecasts and subsequent balancing area reporting reflect the load incorporated within its balancing area boundaries.

3.3. If the reliability impact of the pseudo-tie cannot be accurately captured in the IDC and the security analysis system models of other transmission providers, balancing areas, and Reliability Coordinators, the parties must implement the dynamic transfer either through use of a dynamic schedule, or through a combined implementation of pseudo-tie and dynamic schedule where the load or generation within the native balancing area is separately modeled in the IDC.

3.4. The drafting team should consider clarifying how pseudo-tie can be used in reliability analysis activities. For example, since they are not physical ties, should they be omitted from being used as part of a defined flowgate and in physical interface calculations yet be included in inadvertent calculations

4. Pseudo-Ties Coordination and Scheduling

4.1. Subsequent to moving load or resources into an attaining balancing area through pseudo-ties, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated by the attaining balancing area.

4.2. The attaining balancing area assumes responsibility for balancing area services required by the assigned loads and/or resources. The attaining balancing area assumes all regulation, contingency reserves, and other balancing area responsibilities for the loads and/or resources in question.

4.3. Energy exchanged between the native and attaining balancing areas by the pseudo-tie method is accounted for by the associated revenue meter reading for the operating hour (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal over the operating hour. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

5. Trouble Response

5.1. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie on a plan for how the balancing areas will operate during a loss of the pseudo-tie telemetry signal such that all involved balancing areas are using the same value. The balancing areas may agree to hold the last known good value, use an average load profile value, or have one party provide the other with a manual override value at some acceptable frequency of update.

5.2. The native balancing area, attaining balancing area, and intermediary balancing areas shall agree before implementation of the pseudo-tie upon a plan for how the load will be served during abnormal system conditions including periods of time when the interconnection between them is lost. The native balancing area, attaining balancing area, and intermediary balancing areas shall also agree before implementation of the pseudo-tie how the entities will respond during abnormal system conditions, including periods of time when the connection between them is unavailable.

Dynamic Transfer Reference Document

The Drafting Team should take the existing Dynamic Transfer Reference Document, update it as necessary to reflect Functional Model terms and any changes necessary as a result of new requirements from the standards drafting resulting from this SAR and submit it for ballot as a formal reference document linked to those standards. This will provide the industry with a formal, official document to provide guidance on the implementation of dynamic transfers covered in the standards.

The Interchange Subcommittee recommends moving INT-001 standard requirement R.1. to a more appropriate INT standard such as INT-001 or INT-003.

Note: In addition to the above requirements, the NERC Glossary of Terms may need to be amended to include the following new or revised definitions:

ATTAINING BALANCING AREA — A balancing area bringing generation or load into its effective control boundaries through dynamic transfer from the Native Balancing area.

DYNAMIC SCHEDULE — A telemetered reading, or value that is updated in real-time and used as a schedule in the AGC/ACE equation of the affected balancing areas and the integration of which is treated as a schedule for interchange accounting purposes. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a scheduled MWh value for interchange accounting purposes.

DYNAMIC TRANSFER — The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to implement a dynamic schedule or pseudo-tie.

INTEGRATION in the context of dynamic schedules and pseudo-ties means the value could be mathematically calculated or determined mechanically with a metering device.

INTERCONNECTED OPERATIONS SERVICE (IOS) — A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected bulk electric systems.

NATIVE BALANCING AREA — A balancing area from which a portion of its physically interconnected generation and/or load is assigned from its effective control boundaries through dynamic transfer to the attaining balancing area.

PSEUDO-TIE — A telemetered reading, or value that is updated in real time, representative of generation or load assigned dynamically between balancing areas and used as a tie line flow in the affected balancing areas’ AGC/ACE equation, but for which no physical balancing area tie actually exists. To the extent that no associated energy metering equipment exists, the integration of the telemetered real time signal is used as a metered MWh value for interchange accounting purposes.