NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Dynamic Transfer Reference Document

Version 4

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RELIABILITY | RESILIENCE | SECURITY




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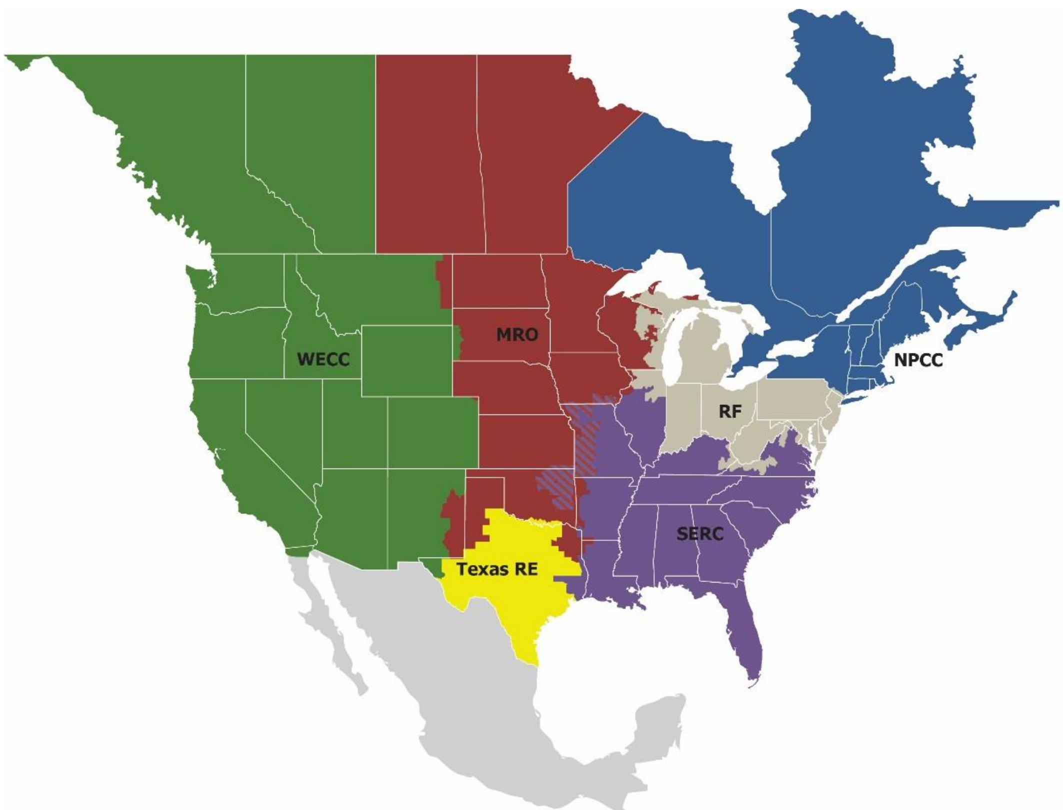
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Overview

Purpose

The purpose of this document is to provide guidance and encourage consistency in the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a Dynamic Transfer.

It is not within the scope of this reference document to require any organization to modify any existing Dynamic Transfers.

Terms

Attaining Balancing Authority: The Balancing Authority (BA) bringing generation or load into its effective control boundaries through Dynamic Transfer from the Native BA.

Dynamic Transfer: The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BA Area into another.

Dynamic Transfer Signal: The electronic signal used to implement a Pseudo-Tie or Dynamic Schedule using either a metered value or a calculated value.

Dynamic Schedule or Dynamic Interchange Schedule: A telemetered reading or value that is updated in real time and used as a schedule in the automatic generator control (AGC)/area control error (ACE) equation and the integrated value of which is treated as a schedule for interchange accounting purposes.

Integration: In the terms for Dynamic Schedule and Pseudo-Tie above means the value could be mathematically calculated or determined mechanically with a metering device and incorporated into the associated ACE calculations for the Attaining and Native BA.

Native BA: The BA 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 BA.

Attaining Reliability Coordinator: The Reliability Coordinator (RC) for the Attaining BA.

Native RC: The RC for the Native BA.

Pseudo-Tie: A time-varying energy transfer that is updated in real-time and included in the actual net interchange term (NIA) in the same manner as a tie line in the affected BA's reporting ACE equation (or alternate control processes).

Chapter 1: Dynamic Schedule versus Pseudo-Tie Fundamentals

The key difference between Pseudo-Ties and Dynamic Schedule is often viewed only as a system control issue. Discussions are typically limited to how the transfer is implemented in each BA's ACE equations and in the associated energy accounting process. Pseudo-Ties are accounted for by all parties as actual interchange, and Dynamic Schedule are accounted for as scheduled interchange. However, there are other factors that must be considered when determining which type of Dynamic Transfer should be utilized for a given situation. The descriptions provided in this document are based on practical experience where Dynamic Transfers have been successfully implemented.

From a simple perspective, a Dynamic Schedule is a means of achieving a time-varying exchange of power where traditional block scheduling is not sufficient. Examples might be the partial or complete exchange of regulating obligations (see **Appendix B**), the temporary provision of power under a reserve sharing agreement, or the exchange of power to serve a real-time demand signal.

Pseudo-Ties are typically, but not exclusively, used to represent Interconnections between two BAs at generation or load, similar to a physical tie line. These loads/generators, however, are at locations where no other physical connection exists between the load/generation and the power system network of the responsible Attaining BA's traditional control boundaries defined by its physical tie lines. In the instance of a Pseudo-Tie, the operational and procedural responsibility[1] for a source of load/generation is key and must be coordinated between all impacted BAs and RCs. In addition to system control responsibility that is traditionally considered, the responsibilities related to a Pseudo-Tie extend to such requirements as Disturbance Control Standard (DCS) recovery, load shedding, transmission and ancillary services, load forecasting, and system operating limit/Interconnection reliability operating limit mitigation, etc. associated with the load/generation.

Although both Pseudo-Ties and Dynamic Schedule involve time-varying quantities, unlike a Pseudo-Tie, a Dynamic Schedule may have no specific load/generation for which the Attaining BA is operationally or procedurally responsible.

The choice of a Pseudo-Tie versus a Dynamic Schedule can be adapted to suit any implementation between the Native and Attaining BAs as long as both BAs agree which one is responsible for each of the obligations associated with the load/generation. For example, a Pseudo-Tie would typically be used to represent a generator owned by an Attaining BA that is located within the physical tie line boundary of a Native BA. However, a Dynamic Schedule implementation can be used in each BA's ACE equation as long as responsibility for obligations, such as recovery during a DCS event, are clearly understood and accepted by both BAs.

[1] Procedural responsibility refers to which BA area's, RC area's and/or which ERO Region's requirements will apply to the generator or load

Chapter 2: Dynamic Transfer Implementation Considerations

There are numerous considerations that the Attaining BA and the Native BA must address during the design and implementation of a Dynamic Transfer. This chapter identifies areas that should be discussed and agreed upon during the development of a new Dynamic Transfer. Dynamic Transfers can be used for, but not limited to, the following scenarios:

- To transfer all of, or a portion of, actual output of a specific generator to another BA in real-time.
- To provide the real-time power requirements for a load physically located in the Attaining BA from resources in the Native BA.
- To supply one or more interconnected operation services to generators and/or loads between the Native and Attaining BA.
- To provide a mechanism for reserve sharing.
- To provide supplemental regulation.

The particular Dynamic Transfer method to be utilized for a specific operating arrangement may be dependent on some or all of the following:

- The desired service(s) to be provided.
- The capability to capture the Dynamic Transfer in system models.
- Responsibility for forecasting load.
- Responsibility for providing unit commitment and maintenance information.
- Energy Management System (EMS) capability.

Each BA is obligated to fulfill its commitment to the Interconnection and not burden other BAs. The use of a Dynamic Transfer does not in any way diminish this responsibility. The following list of obligations should be discussed and accounted for in the design and implementation of a Dynamic Transfer:

- Before implementing the Dynamic Transfer, all parties to the Dynamic Transfer must agree on all implementation details.
- Any errors resulting from an improperly implemented or operated Dynamic Transfer (including inadvertent interchange accumulations) must be resolved between the involved parties.
- Dynamic Transfers must not include any control offsets that are not explicitly compliant with the requirements set forth in NERC Reliability Standards (e.g., unilateral inadvertent payback, Western Interconnection automatic time error control, etc.).
- Applicable tariff requirements of all involved or affected transmission providers and BAs must be met; this includes proper handling and accounting for energy losses.
- If the Dynamic Transfer includes a prearranged calculated assistance or distribution of responsibility between the Native BA and the Attaining BA for recovery from the loss of generation, then both BAs are responsible for ensuring that their respective DCS compliance requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event.

From a system modeling perspective, the assignment of load or generation into the control response of another BA must be appropriately captured in the reliability analysis tools. It is the obligation of each BA involved in the Dynamic

Transfer to ensure that the Dynamic Transfer of load or generation is coordinated with their Transmission Operator (TOP) and RC so that the method of Dynamic Transfer can be considered in the system modeling of the generation or load affected and that the necessary data provision requirements are met. These provisions are listed as follows:

- To assure proper resource application, it is the responsibility of the Attaining BA dynamically transferring load into its effective boundaries through Pseudo-Ties to ensure that load forecasts and subsequent BA reporting reflect the load incorporated within its BA boundaries. Conversely, when a Dynamic Schedule is used to serve load within another BA area, the BA where the load is electrically connected (Native BA) must include that load in its BA load forecast and any subsequent reporting as needed.
- It is the responsibility of both the Native BA/TOP/RC and Attaining BA/TOP/RC to model any generation or load serving Dynamic Transfers in their respective power flow models, real-time assessments (RTAs) and modeled in the interchange distribution calculator (IDC) correctly. This modeling is required to ensure that affected BAs/TOPs/RCs study the generation or load regardless of the control boundary designations. This modeling also is necessary to ensure that each BA/TOP/RC can see the impact of the Dynamic Transfer on their systems.
- Dynamic Transfers must not affect reliability adversely. If the reliability impact of a Dynamic Transfer that has been implemented as a Pseudo-Tie cannot be addressed adequately without modeling it in the IDC or other applicable RTA system models that use scheduled values, then the Dynamic Transfer must be performed via a Dynamic Schedule.

For both Pseudo-Ties and Dynamic Schedule, the BAs shall adjust their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BAs in accordance with the NERC process as referenced in *Balancing Authority Area Footprint Change Tasks Reference Document* [2]

There are occasions when changes are needed to bias settings outside of the normal schedule. Examples are footprint changes between BAs and major changes in load or generation or the formation of new BAs. In such cases the changing BAs should reference the *Balancing Authority Area Footprint Change Tasks Reference Document* and work with their Regions and NERC to confirm appropriate changes to bias settings, FRO, CPS limits and Inadvertent Interchange balances.

The Native, Attaining, and Intermediate BAs must carefully coordinate many aspects related to Dynamic Transfers. Failure to do so may result in the creation of reliability problems for the Interconnection, may create after-the- fact energy accounting and billing problems, and may cause violations of industry standards. Below is a list of conditions that the participating BAs should ensure have been addressed prior to implementing a new Dynamic Transfer:

- Control offsets are compliant with applicable industry standards.
- Tariff requirements are met.
- DCS reporting requirements have been addressed.
- Transmission service has been addressed.
- Need for inclusion in reliability tools has been addressed.
- Transferred loads and/or generation are accounted for in energy dispatch.
- Transferred loads and/or generation are still included in relevant RTA tools.
- Frequency bias impacts have been addressed.
- Contingency plans for loss of Dynamic Transfer signal and telecommunications have been addressed.

[2] https://www.nerc.com/comm/OC/ReferenceDocumentsDL/BAA_Footprint_Change_Reference_Document_March_2019.pdf

- Contingency plans for transmission constraints that prohibit the Dynamic Transfer.
- Industry compliance issues such as NERC and NAESB have been addressed.
- Energy accounting practices are consistent, including losses.
- The ancillary service provision has been addressed.
- Impact on reserve requirements have been addressed.
- Impact on under-frequency load shedding relays have been addressed.
- Dynamic Transfers must be included in congestion management.
- Primary and secondary telemetry methods for required data have been addressed.
- Ramp rates limitations have been addressed.

Table 2.1 describes and outlines the obligations associated with the typical historical application of Pseudo-Ties and Dynamic Schedule related to many of the topics addressed above. In practical application, however, both the Native and Attaining BAs can agree to exchange the obligations from that shown in **Table 2.1**. Additional coordination obligations with respect to pseudo ties and RC are listed in **Chapter 4**.

Table 2.1: Assignment of BA Obligations

BA's Obligation/modeling	Pseudo-Tie	Dynamic Schedule
Generation planning and reporting and outage coordination	Attaining BA	Typically, Native BA but may be reassigned (wholly or a portion) to the Attaining BA
CPS and DCS recovery/reporting and RMS	Attaining BA	Attaining and/or Native BA (depending on agreements)
Operational responsibility	Attaining BA	Native BA
BA services	Attaining BA	Native BA
FERC Open Access Transmission Tariff (OATT) Schedules 3–6 and other ancillary services as required		
Ancillary services associated with transmission FERC OATT Schedules 1–2 and other ancillary services as required	Attaining/Native BA (as agreed)	Attaining/Native BA (as agreed)
ACE frequency bias calc/setting	The Native and Attaining BAs shall adjust their frequency bias setting to account for the frequency bias characteristics of the loads and/or resources being assigned between BAs by the Pseudo-Tie	The Attaining BA should include the load from its Dynamic Schedule as a part of its forecast load to set frequency bias requirement. The Native BA should change its load used to set frequency bias setting by the same amount in the opposite direction.
Load forecasting and reporting	Attaining BA	Native BA
Manual load shedding during an Energy Emergency Alert	Attaining BA	Native BA
Coordination with RC for inclusion in congestion	Attaining BA if within one RC	Native BA if within one RC

Table 2.1: Assignment of BA Obligations		
BA's Obligation/modeling	**Pseudo-Tie**	**Dynamic Schedule**
Management	Both Attaining and Native BA if spanning multiple RC's	Both Attaining and Native BA if spanning multiple RC's
Note: **Table 2.1** contains the typical BA obligations that have been utilized throughout the industry for pseudo- ties and Dynamic Schedule. However, for any specific Dynamic Transfer implementation, both the Native and Attaining BAs can agree to exchange the obligations.		

Chapter 3: Dynamic Schedule Implementation and Coordination

A Dynamic Schedule is implemented as an interchange transaction that is modified in real-time to transfer time-varying amounts of power between BAs. A Dynamic Schedule typically does not change a BA's or RC's operational responsibility (i.e., the Native BA/RC continues to exercise operational control over and provides basic BA/RC services to the dynamically scheduled resources).

Dynamic Schedule are to be accounted for as interchange schedules by the source, sink, and contract intermediary BAs both in their respective ACE equations and throughout all of their energy accounting processes. Requirements to incorporate a Dynamic Schedule into the contract intermediary BA's ACE are subject to regional procedures.

All Dynamic Schedule used for supplemental regulation or to assign the control of generation, loads, or resources from one BA to another must meet the following requirements:

- **Telemetry:** Appropriate telemetry must be in place and incorporated by all affected BAs in accordance with all NERC Reliability Standards, especially the Disturbance Control Performance standard.
- **Transmission Service:** Prior to implementation of the Dynamic Schedule of load or generation, all applicable NERC interchange Reliability Standards need to be met, including ancillary services and provision of losses.
- If transmission service between the source and sink BAs is curtailed then the allowable range of the magnitude of the schedules between them, including Dynamic Schedule, may have to be curtailed accordingly. All BAs involved in a Dynamic Schedule curtailment must also adjust the Dynamic Schedule signal input to their respective ACE equations to a common value. The value used must be equal to or less than the curtailed Dynamic Schedule tag. Since Dynamic Schedule tags are generally not used as Dynamic Transfer signals for ACE, this adjustment may require manual entry or other revision to a telemetered or calculated value used by the ACE.
- **System Modeling:** When a Dynamic Schedule is used to serve load within another BA area, the BA where the load is electrically connected (Native BA) must include this load in its BA load forecast for both energy dispatch and RTA 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).
- **Dynamic Schedule Coordination and Scheduling:** The implementation of a Dynamic Schedule must be through the use of an interchange transaction between BAs. As such, all Dynamic Schedule shall be implemented in accordance with NERC reliability standards. All Dynamic Schedule impacts are reflected in market flow calculations for entities that report market flows unless that entity has requested an exemption and that exemption has been requested and approved as specified in: ACE Equation Implications of Dynamic Transfers Appendix A: ACE Equation Implications of Dynamic Transfers.

  Energy exchanged between the source, sink, and intermediary BAs as a Dynamic Schedule is the metered or calculated (obtained by the integration of the Dynamic Schedule signal) energy for the loads and/or resources. Agreements must be in place with the applicable transmission providers to address the physical or financial provision of transmission losses.

  The Native BA must ensure that agreements are in place that define the responsibility for providing applicable ancillary/interconnected operations services.

  If the power flows associated with the Dynamic Schedule are expected to be bi-directional, two separate Dynamic Schedule are required (each schedule to be implemented as unidirectional following the "gen-to-load" direction convention). This expectation is a result of the fact that transmission service would be required for the Dynamic Schedule and most often import and export transmission services are provided as separate reservations.

- **Contingency Response:** Before implementation of the Dynamic Schedule, the involved BAs shall agree on a plan. The plan should ensure that operating practices have been established:
    - To operate during a loss of the Dynamic Schedule telemetry signal such that all involved BAs are using the same value (including periods of time when the interconnection between them is unavailable). The BAs 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.
    - To serve the load during system conditions which prevent delivery of the Dynamic Schedule from the generation to the load.
    - To re-dispatch the generation that had served the dynamically scheduled load prior to the system conditions which prevent delivery from the generation to the load.
- Compliance with NERC Reliability Standards.

The implementation of a Dynamic Schedule may confer upon the Attaining BA additional responsibilities for compliance with NERC Reliability Standards for the load or generation that has been transferred.

Chapter 4: Pseudo-Tie Implementation and Coordination

Pseudo-Ties are often employed to assign generators, loads, or both from the BA to which they are physically connected to a BA that has effective operational control. Thus, Pseudo-Ties often provide for a change of BA operational responsibility from the Native to the Attaining BA and make the Attaining BA provider of BA services at the same time. In practice, Pseudo-Ties may be implemented based upon metered or calculated values. All BAs involved account for power exchange and associated transmission losses as actual interchange between the BAs 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 BA to the Attaining BA must meet the following requirements:

- **Telemetry:** Prior to implementation of the Pseudo-Tie transfer of load or generation, all applicable NERC Reliability Standards need to be met, including:
  - common metering points
  - adequate communications infrastructure

  The requirement for common metering points and adequate communications infrastructure does not imply specific ownership of telemetry devices.

- **Transmission Service:** Prior to implementation of the Pseudo-Tie transfer of load or generation, each involved BA shall ensure that the Dynamic Transfer is implemented such that the tariff requirements of the applicable transmission provider(s), including applicable ancillary services and provision of losses, are met.

  If transmission service between the Native and Attaining BAs is curtailed, then the allowable range of the magnitude of the Pseudo-Ties between them must be limited accordingly to these constraints.

  Agreements must be in place with the applicable transmission providers to address the physical and/or financial provision of transmission losses.

- **System Modeling:** The Attaining BA dynamically transferring load into its effective boundaries through a Pseudo-Tie shall ensure that load forecasts used for energy dispatch and subsequent BA reporting reflect the load incorporated within its BA boundaries. The Native BA would continue to consider this load in load forecasts used for its RTA.

  If the reliability impact of the Pseudo-Tie cannot be accurately captured in the IDC and/or any other RTA system models of the reliability entities impacted by the Dynamic Transfer, then the Dynamic Transfer must be implemented as a Dynamic Schedule.

- **Pseudo-Tie Coordination and Scheduling:** Subsequent to moving load or resources into an Attaining BA through Pseudo-Tie transfers, all interchange transactions or other energy transfers to the loads or from the resources must be coordinated among the Attaining intermediary and Native BAs in accordance with the NERC Reliability Standards.
  - The Attaining BA assumes responsibility for BA services required by the assigned loads and/or resources. The Attaining BA assumes all regulation, contingency reserves, and other BA responsibilities for the loads and/or resources in question.
  - Energy exchanged between the Native and Attaining BAs by the Pseudo-Tie method is accounted for by the associated revenue meter reading (if such meter exists at the dynamically assigned resource or load) or energy calculated by integrating the associated telemetered real-time signal.

- **Contingency Response:** Before implementation of the Pseudo-Tie transfer, the involved BAs shall agree on a plan:

    - To operate during a loss of the Pseudo-Tie transfer telemetry signal such that all involved BAs are using the same value, including periods of time when the interconnection between them is unavailable. The BAs 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.
    - To serve the load during system conditions that prevent delivery of the Pseudo-Tie transfer from the generation to the load.
    - To re-dispatch the generation that had served the Pseudo-Tie transfer load prior to the system conditions which prevent delivery from the generation to the load.
- **Compliance with NERC Operating Standards**: The implementation of a Pseudo-Tie transfers may confer upon the Attaining BA additional responsibilities for compliance with NERC Reliability Standards for the load or generation that has been transferred.

In addition to the BA to BA coordination requirements listed above, the following items must also be addressed to ensure proper coordination between all impacted BAs and RCs:

- **BA and RC interaction during approval process:** Attaining, Intermediate, and Native BAs should be part of the approval process for implementing Pseudo-Ties as well as Attaining and Native RCs. Attaining BA is defined as a BA that brings generation or load into its effective control boundaries through a Dynamic Transfer from the Native BA. Native BA is defined as BA from which a portion of its physically interconnected generation and/or load is transferred from its effective control boundaries to the Attaining BA through a Dynamic Transfer.
    - Requirements to submit outages for Pseudo-Tied equipment as well as other RC responsibilities (i.e. next day studies, etc.) will be coordinated between the Attaining and Native RCs.
    - RC responsibilities for the Pseudo-Ties shall be agreed upon between involved parties at time of registration of the arrangement. Unit commitment/dispatch plan information for up to seven days out should be made available to the Native RC and interconnected TOP upon request.
    - Transmission service that uses Pseudo-Ties should be accurately reflected in the available Flowgate capability or available transfer capability calculations.
    - Prior to the implementation of new Pseudo-Ties or changes to existing Pseudo-Ties, both the Attaining and Native RCs should have a mutual understanding how operational issues related to the Pseudo-Ties will be administered. These discussions should include designation of each RC responsibilities for the Pseudo-Tied facility and how reliability-related changes to the Pseudo-Tied transaction will be implemented.
- **Firm transmission should be used for the entire path for the Eastern Interconnection:** For proper allocation of network and Native load based on current generation-to-load calculation in the IDC, a Pseudo-Tie must use firm transmission service. Transmission service should be studied with the points of receipt and points of delivery reflecting the specific location of generator or load being Pseudo-Tied. If a transmission service provider offers conditional firm transmission service based on their tariff, the service must be coordinated with their Native RC to ensure the accuracy of their congestion management.

  If firm transmission service is not used for all portion of the path between the Native and Attaining BAs, the Attaining BA must set the pseudo tied generator's priority to non-firm to be consistent with the Parallel Flow Visualization (PFV) requirements set forth by NAESB.[3]
- **Native RC should have authority to direct the generator/load, in order to address local area issues:** The Native RC/TOP should coordinate with the Attaining BA/RC of a Pseudo-Tied generator to dispatch the

[3] https://www.naesb.org/pdf4/weq_bps011812w7.docx

Pseudo-Tied generator to a level that is deemed reliable to manage congestion in a local area issue. The Native RC/TOP may need to request commitment modifications to manage congestion in a local area.

The Native RC and/or TOP should retain the right to issue operating instructions to the Pseudo-Tied unit to modify unit output if needed to resolve a local transmission reliability issue. If there are conflicts in operating instructions between the Native RC/TOP and the Attaining RC/TOP of a Pseudo-Tied generator, the Native RC/TOP and Attaining RC/TOP shall work to resolve the conflict with the Native RC/TOP having priority authorization to resolve the reliability issue.

- **The market entity must be able to accurately calculate market flow impacts from the source:** The market entity, including an external resource/load or collection thereof, should only implement a Pseudo-Tie if the market entity's real-time network model is expanded to at least the location of the source/sink of the Pseudo-Tie and its surrounding buses. This is to ensure that the market entity reports market flow that is reflective of the system conditions throughout the path of the transfer inclusive of external areas on that path and is able to achieve any relief obligation that may be assigned as result of this arrangement. If relief obligation is not met through an accepted congestion management (market flow reallocation or transmission loading relief), manual RC actions may apply.

  The attaining entity must ensure sufficient detail in the IDC model to calculate generation-to-load impacts from the source:

  An entity whose Pseudo-Tie is not being tagged, including an external resource/load or collection thereof, must ensure there is sufficient detail in the IDC model to calculate the generation-to-load impacts that are reflective of the system conditions throughout the path of the transfer that is inclusive of external areas on that path. The RC should ensure any relief obligation that may be assigned as result of this arrangement are realistic. If relief obligation is not met through TLR, a manual RC intervention may apply.

- **Notification to the industry stakeholders:** A notification of future requests for Pseudo-Ties should be made to the NERC Operating Reliability Subcommittee (ORS) by the Attaining RC. The Attaining RC will confirm how these guidelines will be met before implementation of the Pseudo-Ties. To make this process manageable, only Pseudo-Tie notifications where the resource capacity exceeds 20 MW at a single bus, or where the amount of peak load exceeds 50 MW at a single bus, will need to be made to the NERC ORS. The Attaining RC notifies the NERC ORS of such Pseudo-Tie changes to improve situational awareness, and the NERC ORS will not be providing approval or denial of such changes.

  Sufficient notice of a Pseudo-Tie addition needs to be given to affected BAs, TOPS, and RCs to allow changes to be made to their EMS and accounting systems when a Pseudo-Tie is added or removed. This work can take several months to complete.

- **Pseudo-Tie removal:** There are no similar requirements to notify NERC ORS under this guideline when a Pseudo-Tie is removed that results in returning the resource/load back to its Native BA/RC.

  Sufficient notice of a Pseudo-Tie removal needs to be given to affected BAs, TOPS, and RCs to allow changes to be made to their EMS and accounting systems when a Pseudo-Tie is added or removed. This work can take several months to complete.

Appendix A: ACE Equation Implications of Dynamic Transfers

A BA's internal obligations, along with the small additional "bias" obligation to maintain frequency, is represented via a real-time value called ACE, estimated in MW. Dynamic Transfers have an impact on the calculation of ACE and should be included into the respective ACE calculations as part of implementation. This appendix provides the base ACE equation along with examples of how to adjust the base a BA's ACE equation to support the implementation of Dynamic Transfers.

$$ACE = \{[\text{net actual interchange}] - [\text{net schedule interchange}]\} - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$ [4]

$$ACE = \{[NI_A] - [NI_S]\} - 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}$$

$$\begin{aligned} ACE = \{&[(NI_a) + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NI_{ARSE} - NI_{ARSI})] \\ &- [(NI_s) + (- NI_{SDSGE} + NI_{SDSGI} + NI_{SDSLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})]\} \\ &- 10F_b\,(F_A - F_S) - I_{ME} \end{aligned}$$

Where:

Net Actual Interchange (NI_A)

Affected by Pseudo-Ties/AGC interchanges

NI_A = (SUM of Tie Lines) + (SUM of Pseudo-Ties)
$NI_A = (NI_a) + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NI_{ARSE} - NI_{ARSI})$

Where:

NI_a = Net sum of tie line flows

NI_{APTGE} = Sum of AGC Pseudo-Tie interchange generation external to the Attaining BA.

NI_{APTGI} = Sum of AGC Pseudo-Tie interchange generation internal to the BA (Native BA).

NI_{APTLE} = Sum of AGC Pseudo-Tie interchange load external to the BA (Attaining BA).

NI_{APTLI} = Sum of AGC Pseudo-Tie interchange load internal to the BA (Native BA).

NI_{ARSE} = Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via Pseudo-Tie. See **Appendix C**.

NI_{ARSI} = Supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via Pseudo-Tie. See **Appendix C**.

And where values for all generation and load terms are assumed to be positive quantities.

[4] I_{ATEC} is specifically used in the Western Interconnection

Net Scheduled Interchange (NI_S)

Affected by Dynamic Schedule and supplemental regulation services.

NI_S **=** (SUM of non-dynamically scheduled transactions) + (SUM of Dynamic Schedule) $NI_S = (NI_s) + (- NI_{SDSGE} + NI_{SDSGI} + NI_{SDSLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})$

Where:

NI_s	=	Net sum of non-dynamically scheduled transactions
NI_{SDSGE}	=	Sum of dynamically scheduled generation external to the Attaining BA
NI_{SDSGI}	=	Sum of dynamically scheduled generation internal to the Native BA
NI_{SDSLE}	=	Sum of dynamically scheduled load external to the Attaining BA
NI_{SDSLI}	=	Sum of dynamically scheduled load internal to the Native BA
NI_{SRSE}	=	Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service). See **Appendix B**
NI_{SRSI}	=	Supplemental regulation service internal to the BA (BA selling the supplemental regulation service). See **Appendix B**

Where values for all generation and load terms are assumed to be positive quantities.

Terms Unaffected by Dynamic Transfers

B = BA frequency bias

F_A = actual frequency

F_S = scheduled frequency

I_{ME} = meter error correction

I_{ATEC} = automatic time error correction (If implemented within Interconnection)

$$
\begin{aligned}
ACE = \{&[(NI_a) + (NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + NI_{ARSE} - NI_{ARSI})] \\
&- [(NI_s) + (- NI_{SDSGE} + NI_{SDSGI} + NI_{SDSLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})]\} \\
&- 10B\,(F_A - F_S) - I_{ME} + I_{ATEC}
\end{aligned}
$$

ACE Equation Component Tables

The following tables depict the specific ACE equation components that should be included by each BA if implementing Dynamic Transfers.

Application of Pseudo-Ties in ACE by BAs

Application of Pseudo-Tie between adjacent BAs (BA_A and BA_B are adjacent)

Table A.1: Application of Pseudo-Ties between Adjacent BAs			
Pseudo-Tie Transfer	**Path**	**BA_A ACE Inclusions**	**BA_B ACE Inclusions**
Generator from BA_A to BA_B	BA_A -> BA_B	NI_{APTGI}	NI_{APTGE}
Load from BA_A to BA_B	BA_A -> BA_B	NI_{APTLI}	NI_{APTLE}

Application of Pseudo-Tie between two BAs including an Intermediate BA (BA_D and BA_F are non-adjacent and flow traverses BA_E)

Table A.2: Application of Pseudo-Ties between Intermediate BAs				
Pseudo-Tie Transfer	**Path**	**BA_D ACE Inclusions**	**BA_E ACE Inclusions**	**BA_F ACE Inclusions**
Generator from BA_D to BA_F	BA_D -> BA_E -> BA_F	NI_{APTGI}	NI_{APTGE} NI_{APTGI}	NI_{APTGE}
Load from BA_A to BA_B	BA_A -> BA_B	NI_{APTLI}	NI_{APTLE} NI_{APTLI}	NI_{APTLE}

Application of Dynamic Schedule in ACE by BAs

Application of Dynamic Schedule between adjacent BAs

Table A.3: Application of Dynamic Schedule between Adjacent BAs			
Dynamic Schedule Transfer	**Path**	**BA_A ACE Inclusions**	**BA_B ACE Inclusions**
Generator from BA_A to BA_B	BA_A -> BA_B	NI_{SDSGI}	NI_{SDSGE}
Load from BA_A to BA_B	BA_A -> BA_B	NI_{SDSLI}	NI_{SDSLE}

Application of Dynamic Schedule between two BAs, including an Intermediate BA (BA_D and BA_F are non-adjacent and flow traverses BA_E)

Table A.4: Application of Dynamic Schedule between Intermediate BAs				
Dynamic Schedule Transfer	**Path**	**BA_D ACE Inclusions**	**BA_E ACE Inclusions**	**BA_F ACE Inclusions**
Generator from BA_D to BA_F	BA_D -> BA_E -> BA_F	NI_{SDSGI}	NI_{SDSGE} NI_{SDSGI}	NI_{SDSGE}
Load from BA_A to BA_B	BA_D -> BA_E -> BA_F	NI_{SDSLI}	NI_{SDSLE} NI_{SDSLI}	NI_{SDSLE}

Dynamic Transfer Numeric Examples

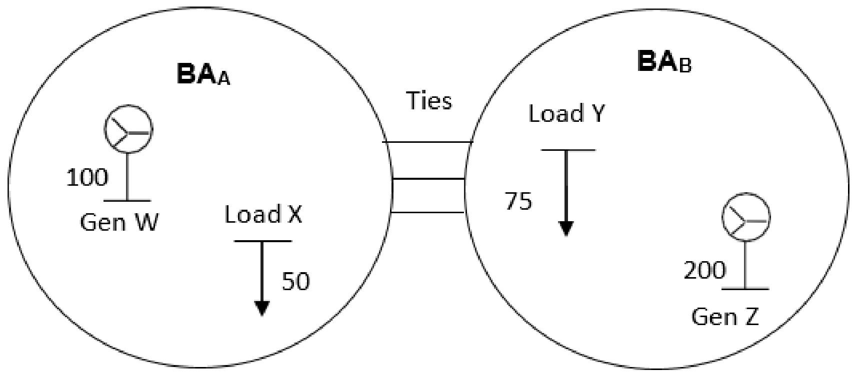


Figure A.1: Numeric Examples

Assume: Net sum of tie flows = 0, Net sum of non-dynamically scheduled transactions = 0, $F_S = F_A$, and $I_{ME} = 0$

In **Figure A.1**, BA$_A$ will become the Attaining BA for load Y and generator Z. Similarly, BA$_B$ East will become the Attaining BA for load X and generator W.

Using Pseudo-Ties

Using **Table A.1** to obtain the correct net actual interchange terms for the Pseudo-Ties, the ACE equation becomes the following:

$ACE\ BA_A = NI_A - NI_S = (NI_A + NI_{APTGI(Z)} - NI_{APTGE(W)} - NI_{APTGI(Y)} + NI_{APTGE(X))} - NIS = (NI_a + Gen\ Z - Gen\ W - Load\ Y + Load\ X) - NI_S$

Substituting the values in the example as positive quantities, the equation becomes as follows:

$ACE\ BA_A = (0 + 200 - 100 - 75 + 50) - 0 = 75$

Using Dynamic Schedule

Using **Table A.3** to obtain the correct net scheduled interchange terms for the Dynamic Schedule, the ACE equation for BA$_A$ becomes the following:

$ACE\ BA_A = NI_A - NI_S = NI_A - (NI_s - NI_{SDSGE(Z)} + NI_{SDSGI(W)} + NI_{SDSLE(Y)} - NI_{SDSLI(X)}) = NI_A - (NI_s - Gen\ Z + Gen\ W + Load\ Y - Load\ X)$

Substituting the values in the example as positive quantities, the equation becomes as follows:

$ACE\ BA_A = 0 - (0 - 200 + 100 + 75 - 50) = 0 - (-75) = 75$

Using both Pseudo-Ties and Dynamic Schedule

Assume that the generation will be modeled as Dynamic Schedule and the loads as Pseudo-Ties. Using **Table A.1** and **Table A.3** to obtain the correct net scheduled interchange and net actual interchange terms for the Dynamic Transfers, the ACE equation for BA West becomes as follows:

$ACE\ BA_A = NI_A - NI_S = (NI_A - NI_{APTLI(Y)} + NI_{APTLE(X)}) - (NI_S - NI_{SDSGE(Z)} + NI_{SDSGI(W)}) = (NI_a - Load\ Y + Load\ X) - (NI_s - Gen\ Z + Gen\ W)$

Substituting the values in the example as positive quantities, the equation becomes as follows:

$ACE\ BA_A = (0 - 75 + 50) - (0 - 200 + 100) = (-25) - (-100) = -25 + 100 = 75$

Note: In all cases, the ACE value is the same regardless of the Dynamic Transfer method used.

Appendix B: Supplemental Regulation Service as a Dynamic Schedule

Supplemental regulation service is when one BA provides part of the regulation requirements of another BA. The BAs implement a Dynamic Schedule that incorporates the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the scheduled interchange ACE equation for both BAs. Care should be taken to maintain the proper sign convention to ensure proper control with the BA purchasing regulation service subtracting the supplemental regulation service from the scheduling component of their ACE while the BA providing the service adds it to the scheduling component of their ACE.

If the supplemental regulation service includes a calculated assistance between the Native BA and the Attaining BA for recovery from the loss of generation, then both BAs are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from Balancing Contingency Event.[5]

ACE Equation Modifications

The ACE equation modifications required for supplemental regulation service are as follows:

Typically:

$ACE = (NI_A - NI_S) - 10B\,(F_A - F_S) - I_{ME}$

Where:

NI_A = net actual interchange
NI_S = net scheduled interchange B = BA frequency bias
F_A = actual frequency
F_S = scheduled frequency I_{ME} = meter error correction

For a Dynamic Schedule the NI_A remains unchanged, but to implement supplemental regulation service, the NI_S term becomes as follows:

$NI_S = NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI}$

Where:

NI_s = Net sum of non-dynamically scheduled transactions
NI_{SDSGE} = sum of dynamically scheduled generation external to the BA (Attaining BA)
NI_{SDSGI} = sum of dynamically scheduled generation internal to the BA (Native BA)
NI_{SDSLE} = sum of dynamically scheduled load external to the BA (Attaining BA)
NI_{SDSLI} = sum of dynamically scheduled load internal to the BA (Native BA)
NI_{SRSE} =Supplemental regulation service external to the BA (BA purchasing the supplemental regulation service)
NI_{SRSI} = Supplemental regulation service internal to the BA (BA selling the supplemental regulation Service)

And where supplemental regulation service for an overgeneration condition is assumed to be negative and for under generation it is positive to achieve the desired effect via NI_S on ACE as described in the *"NAESB WEQ Area Control Error (ACE) Equation Special Cases Standards - WEQBPS – 003-000"*[6]

[5] NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from Balancing Contingency Event
[6] https://www.naesb.org/pdf2/weq_bklet_011505_ace_mc.pdf

Supplemental Regulation as Dynamic Schedule - Numeric Example

Assume: Net sum of tie flows = 0, net sum of non-dynamically scheduled transactions = 20 MW from BA_{-WestA} to BA_{-EastB}, $F_S = F_A$, and $I_{ME} = 0$

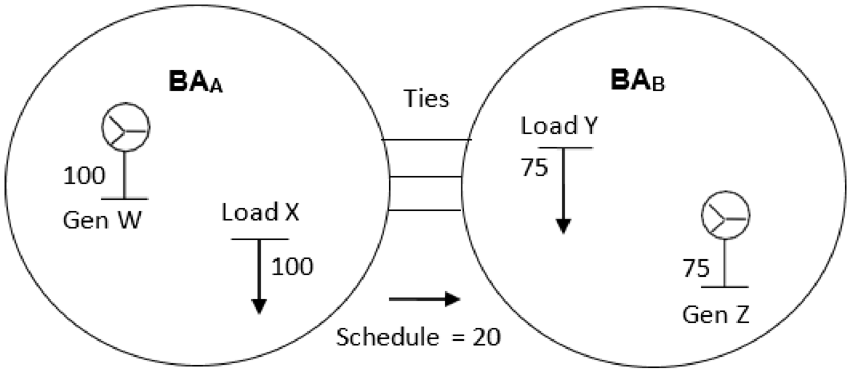


Figure B.1: Numeric Examples

In Numeric Examples**Figure B.1**, BA_A is purchasing 15 MW of supplemental regulation. Similarly, BA_B is selling 15 MW of supplemental regulation.

Using the correct net scheduled interchange terms for supplemental regulation as a Dynamic Schedule, the ACE equation for BA_A becomes as follows:

> ACE $BA_A = NI_A - NI_S = NI_A - (NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})$, simplifying for applicable terms for this example yields, $= NI_A - (NI_s - NI_{SRSE})$

Since purchaser BA_A is in an under-generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes:

> ACE $BA_A = 0 - (20 - 15) = 0 - (5) = -5$

Similarly, the ACE equation for BA East becomes:

> ACE $BA_B = NI_A - NI_S = NI_A - (NI_s - NI_{SDSGE} + NI_{SDSGI} + NI_{SDGLE} - NI_{SDSLI} - NI_{SRSE} + NI_{SRSI})$, simplifying for applicable terms for this example yields, $= NI_A - (NI_s + NI_{SRSI})$

Again, since purchaser BA_A is in an under generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

> ACE $BA_B = 0 - (-20 + 15) = 0 - (-5) = 5$

Appendix C: Supplemental Regulation Service as a Pseudo-Tie

Supplemental regulation service is when one BA provides all or part of the regulation requirements of another BA. The BAs implement a Pseudo-Tie that incorporates the calculated portion of the ACE signal that has been agreed upon between them. This is accomplished by adding another component to the actual interchange component of the ACE equation for both BAs. Care should be taken to maintain the proper sign convention to ensure proper control.

If the supplemental regulation service includes a calculated assistance between the Native BA and the Attaining BA for recovery from the loss of generation, then both BAs are responsible for assuring that DCS compliance reporting requirements are met in accordance with NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event.[7]

ACE Equation Modifications

The ACE equation modifications required for supplemental regulation service are as follows:

Typically:

$ACE = (NI_A – NI_S) – 10B (F_A – F_S) – I_{ME}$

Where:

NI_A = net actual interchange
NI_S = net scheduled interchange B = BA frequency bias
F_A = actual frequency
F_S = scheduled frequency I_{ME} = meter error correction

For a Pseudo-Tie with supplemental regulation, the NI_S remains unchanged, but the NI_A term becomes as follows:

$NI_A = NI_a + (NI_{APTGE} – NI_{APTGI} – NI_{APTLE} + NI_{APTLI} + N_{ARSE} - N_{ARSI})$

Where:

NI_a = Net sum of tie line flows.
NI_{APTGE} = sum of AGC interchange generation external to the Attaining BA.
NI_{APTGI} = sum of AGC interchange generation internal to the BA (Native BA).
NI_{APTLE} = sum of AGC interchange load external to the BA (Attaining BA).
NI_{APTLI} = sum of AGC interchange load internal to the BA (Native BA).
NI_{ARSE} = supplemental regulation service external to the BA (BA purchasing the supplemental regulation service) via Pseudo-Tie.
NI_{ARSI} = supplemental regulation service internal to the BA (BA selling the supplemental regulation service) via Pseudo-Tie.

As with Dynamic Schedule for both the purchasing and selling BAs, supplemental service being provided to alleviate overgeneration has a negative sign while supplemental service being provided to alleviate under generation has a positive sign.

[7] NERC Standard BAL-002-3 — Disturbance Control Standard – Contingency Reserve for Recovery from Balancing Contingency Event

Supplemental Regulation as Pseudo-Tie - Numeric Example

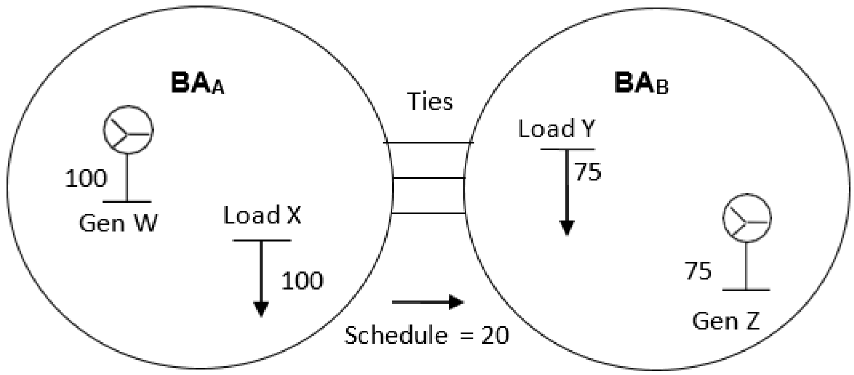


Figure C.1: Numeric Example

Assume:

> Net sum of tie flows = 0,
> Net sum of non-dynamically scheduled transactions = 20 MW from BA_A-West to BA_B-East,
> $F_S = F_A$ and $I_{ME} = 0$

In **Figure C.1**, BA_A will become the BA purchasing 15 MW of supplemental regulation. Similarly, BA_B will become the BA selling 15 Mw of supplemental regulation.

Using the correct net actual interchange terms for supplemental regulation as a Pseudo-Tie, the ACE equation for BA_A becomes as follows:

> ACE $BA_A = NI_A - NI_S = (NI_a + NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + N_{ARSE} - N_{ARSI}) - NI_S$, simplifying for applicable terms for this example yields, $= (NI_a + N_{ARSE}) - NI_S$

Since purchaser BA_A is in an under-generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

> ACE $BA_A = (0 + 15) - 20 = 15 - 20 = -5$

Similarly, the ACE equation for BA-East becomes:

> As follows: ACE $BA_B = NI_A - NI_S = (NI_a + NI_{APTGE} - NI_{APTGI} - NI_{APTLE} + NI_{APTLI} + N_{ARSE} - N_{ARSI}) - NI_S$, simplifying for applicable terms for this example yields, $= (NI_a - N_{ARSI}) - NI_S$

Again, since purchaser BA_A is in an under generating condition in this example, the supplemental regulation term is positive and substitution in the equation becomes as follows:

> ACE $BA_B = (0 - 15) - (-20) = -15 + 20 = 5$

Appendix D: Dynamic Tag Exclusion Process

Over the years, numerous requests were made to the Interchange Distribution Calculator Working Group (IDCWG) and the ORS in order to accommodate special arrangements for different BAs to support congestion management actions that need to be reflected in the IDC, such as the exclusion of tags with a specific source and sink combination due to the MW impact being included in different curtailable products. These requests have been, up to this point, handled on a case-by-case basis as there is not a consistent process or set of guidelines to ensure such arrangements are implemented with no degradation to reliability or change in equity status for the products.

The ORS created a Task Force to work with the IDCWG to develop a process for the exclusion of tags.

Applicability

This process is applicable to RCs and BAs that manage dynamic tags.

Dynamic Tag Exclusion Management

Approval process

The NERC ORS is not tasked or qualified to approve equity-related issues. The ORS is tasked with ensuring reliability is maintained. Therefore, prior to requesting NERC ORS approval to allow the IDC to ignore a Dynamic Schedule tag, the requesting entity is expected to coordinate with NAESB BPS and/or applicable congestion management oversight policy committees to ensure no equity concerns exist. In addition, the requesting entity must also have approval from the IDCWG to ensure no technical concerns exist. Then the entity may request approval from the ORS.

Requirements for incorporating Dynamic Schedule into Market Flow

If the tagged Dynamic Schedule MW are converted to market flow and ignored by the IDC, the market flow MW representing the converted tag shall have a priority that is no higher than it would have been if the tag was not ignored.

For nonmarket entities, an otherwise tagged MW shall preserve the priority of the transaction if converted to a product not requiring a tag (gen-to-load).

Entity with Flowgates impacted by >5% from tag

Any entity that has Flowgates that are impacted by >5% from the tag can have their Flowgate marked as market coordinated if requested. Any entity that has a Flowgate with >5% impact should be notified prior to the incorporation of the tag and given the opportunity to request market coordinated Flowgates.

To address the impact to these converted transactions, a process or situational awareness tool, such as an IDC display enhancement, may be used to assist non-market entities to determine the impact of the market on a Flowgate in such a situation.

Market entity must be able to accurately calculate market Flow impacts from the source

A market entity, including an external resource or collection of external resources, should only request a tag be ignored by the IDC and reported in market flows if the expanded market base case models or other arrangements are made to maintain accurate market flows. This is to ensure that the market entity reports a market flow that is reflective of the system conditions throughout the transfer path, inclusive of external areas on that path, and is able to achieve any relief obligation that may be assigned as a result of this arrangement. If the relief obligation is not met through an accepted congestion management process (market flow reallocation or transmission loading relief), manual RC intervention may apply.

Appendix E: Revision History

Version	Date	Action	Change Tracking
3	May 10, 2016	Replaced the Frequency Bias Setting section in Chapter 3 to reflect the frequency bias methodology used in BAL-003--1	
4	May 27, 2019	NERC ORS/RS 3-year review and modifications • Updated Version • Addition of Appendix D NERC ORS Dynamic Tag Exclusion Process • Updated Terms and definitions to match NERC Glossary • Minor grammar corrections • Clarified responsibilities and coordination with RC and TOP • Updated Standard References • Clarified inclusion of Dynamic Transfers into congestion management • Added reference to *Balancing Authority Area Footprint Change Task Reference Document* • Removed duplicate sections and sections covered in other referenced documents • Clarified and Added coordination considerations • Updated Equation subscripts to match NERC Definitions • Simplified Tables and Examples	