Transmission Planning Technical Guide

Appendix I: Transfer Capability Methodology

System Planning

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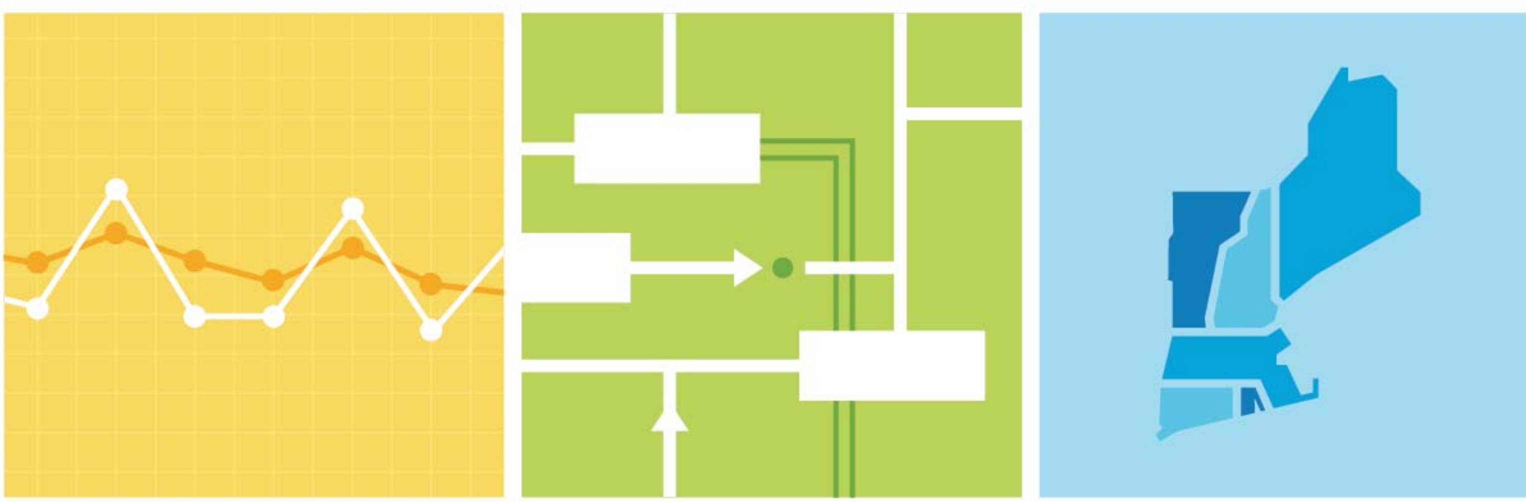

Contents

Section 1
Introduction and Background

1.1 Objective

In accordance with FAC-013 Requirement R1, this document, the power transfer capability methodology document (PTCMD), describes the methodology used to evaluate the planning Transfer Capability (PTC) of the ISO New England (ISO) interfaces for the Near-Term Transmission Planning Horizon[1]. The PTCs are determined, for a period beyond 13 months in the future, in accordance with NERC Standard FAC-013[2] and are not directly related to calculations of Total Transfer Capability (TTC) and Available Transfer Capability (ATC). The ISO New England Available Transfer Capability Implementation Document[3] describes the process for calculating TTC and ATC for the Open Access Same-Time Information Transmission System (OASIS).

1.2 Background – History of FAC-013

The Federal Energy Regulatory Commission (FERC) certified North American Electric Reliability Corporation (NERC) as the Electric Reliability Organization (ERO), as defined in Section 215 of the Federal Power Act, in July 2006. In Order No. 693, FERC reviewed an initial set of Reliability Standards as developed and submitted for review by NERC, accepting 83 standards as mandatory and enforceable. In Order No. 693, FERC accepted Reliability Standard FAC-013-1, which sets out requirements for communication of transfer capability calculations.

In Order No. 693, FERC did not act on Reliability Standard FAC-012-1, which set out proposed requirements for documenting the methodologies used by Reliability Coordinators and Planning Authorities in determining transfer capability.

Subsequently, as part of its submission of revised modeling, data, and analysis (MOD) Reliability Standards, which govern the calculation of ATC, NERC requested that it be permitted to withdraw FAC-012-1 and retire FAC-013-1. In Order No. 729, the FERC found that FAC-012-1 and FAC-013-1 had not been wholly superseded by the revised MOD Reliability Standards because they did not address the calculation of transfer capabilities in the planning horizon. Moreover, the FERC found that the existing versions of FAC-012-1 (as adopted by NERC) and FAC-013-1 (as approved by FERC) were insufficient to address the FERC's concerns, and ordered NERC to develop specific modifications to comply with those outstanding directives.

In its petition, NERC explained that FAC-013-2 was developed in response to FERC directives in Order Nos. 693 and 729 to require appropriate entities to perform an annual assessment of transfer capability in the planning horizon and to do so using data inputs and modeling assumptions that are consistent with other planning uses.

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[1] The transmission planning period that covers years one through five.

[2] FAC standards cover facilities design, connections, and maintenance of the Bulk Electric System.

[3] http://www.oasis.oati.com/ISNE/ISNEdocs/ISNE_ATCID.docx

On November 17, 2011, FERC approved FAC-013-2 and the proposed implementation plan for Reliability Standard FAC-013-2, which retired Reliability Standards FAC-012-1 and FAC-013-1 when FAC-013-2 became effective. The effective date of FAC-013-2 was April 1, 2013.

Section 2
Assessment Information

2.1 Use of Transfer Capability Produced by this Methodology

The planning Transfer Capability (PTC) limits produced by this methodology may be used for the following purposes:

- Creation of base cases to be used for, among others, Needs Assessments and Solutions Studies, System Impact Studies (SIS), Proposed Plan Application (PPA) studies, and various Forward Capacity Market (FCM) analyses
- Transmission Security Assessment calculations
- Performance of Loss-Of-Load-Expectation analyses
- Determination of Installed Capacity and Reserve requirements
- Reporting of PTC limits in reports and filings such as the FERC715

Note: for some uses, a margin may be applied to PTC limits

The calculation of PTCs for the Near-Term Transmission Planning Horizon is not intended to be appropriate to support the real-time operation and scheduling of the ISO transmission system.

2.2 Frequency of Assessment

In accordance with FAC-013 Requirement R4 and Section 2.3 below, the ISO will conduct simulations and document an assessment, during each calendar year, on the planning Transfer Capability across its internal and external interfaces for at least one year in the Near-Term Transmission Planning Horizon. The PTCs may all be evaluated for a single case year, individually for different years, or a combination of both, as appropriate.

The PTCs will be available each year, typically in the first quarter, for inclusion into the FERC 715 filing and during which preparations are done for the upcoming Forward Capacity Auction (FCA). The FCA, performed each February, procures resources three years and four months into the future.

2.3 Interfaces Studied

The ISO calculates PTCs for interfaces that both have significance in the real-time operation of the system and are critical stress points when performing planning or Tariff studies. The selection of interfaces to analyze each year will be based on those listed in the FERC 715 filing. PTCs for interfaces known to be needed to support FCM related activities will be given the highest priority. Next, focus and attention will be given to interfaces that will be impacted by forthcoming significant transmission and/or generation changes.

It's unlikely that the PTC of all New England interfaces will need to be fully assessed, using the approach outlined in Section 5.6, each year. Interfaces for which PTCs have been recently evaluated will not be assessed unless significant transmission and/or generation changes are newly planned. If necessary, these valid PTCs may be re-evaluated for confirmation. Interfaces that are re-assessed will be based on the most limiting conditions unless significant changes are planned which will trigger complete evaluation of the interface(s).

The assessment of the PTC for interfaces internal to the New England transmission system will follow the methodology contained in this document. Where possible, the ISO will work with adjacent Planning Coordinators (PC) when assessing PTC across interfaces between New England and its neighboring systems.

Section 3
Assumptions

The assumptions listed in this methodology and used for the assessment of interface planning Transfer Capabilities are consistent with the ISO's planning procedures.

3.1 Generation Dispatch Assumptions

All existing generating units and those that have received Section I.3.9 approval will be included for assessments of interface planning Transfer Capability. Retired generators will be excluded starting from the year they are to be retired. Additionally, generators associated with the following bids will be modeled as out-of-service if the ISO determines the removal of the generator is likely to have an impact on the transmission transfer limits for the relevant period: Retirement De-List Bids, Permanent De-List bids, demand bids submitting for the upcoming substitution auction, and rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

Known generator outages with a duration that meets or exceeds 12 months, and coincide with a planning Transfer Capability assessment year and season of study shall be considered.

The following ratings shall be used for all generators:

- Maximum rating at 0°F or higher shall be used for light load system conditions
- Maximum rating at 50°F or higher shall be used for summer peak system conditions

The maximum and minimum reactive power limits for all generators shall be based on ISO New England Operating Procedure No. 12 (OP 12), *Voltage and Reactive Control*, Appendix B.

3.2 Transmission Topology Assumptions

All existing transmission elements shall be initially modeled as in service or available when assessing planning Transfer Capability. Transmission projects with Proposed Plan Application (PPA) approval, in accordance with Section I.3.9 of the Tariff, shall be included in the base cases dependent on their in service dates. Retired transmission elements will be excluded starting from the year they are to be retired. Transmission projects that do not have a PPA approval but have been certified under the Forward Capacity Market (FCM) process will be included in the calculation of transfer limits used in the FCM process.

Known transmission system outages with a duration that meets or exceeds 12 months and coincide with a planning Transfer Capability assessment year and season of study shall be considered.

3.3 Load & Demand Resource Assumptions

Assessments of planning Transfer Capability shall utilize the forecasted load as published in the most current ISO New England's Forecast Report of Capacity, Energy, Loads, and Transmission (the CELT Report). Base cases used shall be set up with appropriate loads for the year of study. Station service loads will be explicitly modeled for major generating stations.

Two different load levels are typically used to determine interface transfer limits:

- Light load
- Peak load (defined as 90/10 load)

The load levels and the associated power factors are defined in Section 2.2 of the Transmission Planning Technical Guide.

Active Demand Capacity Resources (ADCR), On-Peak Demand Resources and Seasonal Peak Demand Resources (collectively referred to as passive Demand Capacity Resources) available for a given study year will be utilized for assessments of planning Transfer Capability. Section 2.3.11 of the Transmission Planning Technical Guide lists how demand resources[4] are modeled in base cases.

3.4 Transmission Use Assumptions

The Tariff does not provide a means for long-term transmission service reservations of its Pool Transmission Facilities (PTF). Therefore, no firm or non-firm transmission reservations are modeled.

3.5 Loop Flow Assumptions

Generation dispatches in New York have a significant impact on loop flow through New England, particularly in Massachusetts and Connecticut. The network models explicitly model the tie-lines between the New York and New England Control Areas. Therefore, there are no loop flow adjustments required for assessments of the ISO interface planning Transfer Capability. Any parallel path impacts on inter- and intra-regional interfaces are captured in the simulation results.

3.6 Other Modeling Assumptions

All existing and planned reactive power resources will be assumed available and dispatched as conditions require.

All existing and planned protection and control devices, such as Special Protection Systems (SPS), also known as Remedial Action Schemes (RAS), and phase shifting transformers (PST), will be modeled in the study.

Relevant operating practices will be assumed for the study, such as typical settings for PSTs, series compensation, and HVDC control settings. Section 2 of the Transmission Planning Technical Guide provides information on the operating characteristics of these devices located throughout the New England Control Area.

[4] The generic term demand resource (DR) may include forecasted EE and solar PV.

Section 4
Criteria

The criteria listed in this methodology and used for the assessment of interface PTCs are consistent with the ISO's planning procedures and guidelines.

The following criteria and standards are used when assessing interface PTCs:

- NERC Standard TPL-001, *Transmission System Planning Performance Requirements*
- NPCC Directory #1, *Design and Operation of the Bulk Power System*
- NPCC Document A-10, *Classification of Bulk Power System Elements*
- ISO New England Planning Procedure No. 3 (PP 3), *Reliability Standards for the New England Area Pool Transmission Facilities*

All assessments of interface PTC shall respect all known System Operating Limits (SOL), identified per NERC Standard FAC-010, *System Operating Limits Methodology for the Planning Horizon*, for New England and its neighboring systems. These SOLs are respected by applying the thermal, voltage, and stability criteria in this document, which are as stringent as those used in System Operations. SOLs shall not exceed associated pre-contingency and post-contingency facility ratings. A SOL may be classified as an Interconnection Reliability Operating Limit (IROL). At this time within the ISO Control Area, SOLs and IROLs are not differentiated in the planning horizon because all SOLs are respected independent of the consequence to the transmission system performance. Interfaces that are shared with adjacent PCs will be evaluated using the adjacent PC's criteria on its portion of the system. The criteria listed here will be used for the portion of the system within the ISO Control Area.

4.1 Steady State Thermal Limits

Line and equipment loading shall be applied as described in Section 3.1.1 of the Transmission Planning Technical Guide.

4.2 Steady State Voltage Limits

Steady state voltage limits shall be applied as described in Section 3.1.2 of the Transmission Planning Technical Guide.

4.3 Stability Performance Requirements

Interface PTCs shall adhere to stability performance requirements as listed in Section 3.3 of the Transmission Planning Technical Guide and PP 3.

Section 5
Methodology

Planning Transfer Capability is determined by finding the point where an increase in power transfers causes a limit violation under pre- or post-contingency conditions. The limits governing such power transfers are either based on thermal, voltage, or stability constraints. Various study area dispatch scenarios and system conditions shall be studied to fully assess planning Transfer Capability under all reasonably foreseeable stressed conditions.

5.1 System Models

Power flow cases used in planning Transfer Capability assessments are obtained from the ISO's Model On Demand (MOD) database and supporting applications. The MOD system facilitates the control and organization of the base case and associated data (e.g. projects, loads, etc.). Cases produced by MOD shall reflect system conditions for the year of study. The MOD cases are based on data from the energy management system (EMS) and future system upgrades. The ISO also maintains the stability models for the New England system.

Power flow and stability models for systems external to the ISO originate from the NERC Multi-Regional Modeling Working Group (MMWG).

5.2 Software Tools

Software tools that may be used when assessing planning Transfer Capability include:

1. Siemens Power System Simulation for Engineers (PSS®E)
2. Siemens Managing and Utilizing System Transmission (PSS®MUST)
3. Powertech Dynamic Security Assessment Tools (DSA Tools)
4. PowerGEM Transmission Adequacy and Reliability Assessment (TARA)

Other software tools may be used as required.

5.3 Contingency Selection

The contingencies considered for assessments of planning Transfer Capability are provided in the NERC TPL Standards, NPCC Directory #1, and ISO PP 3.

Interfaces will be evaluated under all contingencies noted in those documents. Consistent with the above standards, certain interfaces will be evaluated with a facility initially out of service (N-1-1). Generation re-dispatch in New England, system adjustments such as phase-angle regulator adjustment, or HVDC adjustments between the first and second contingency event will also be applied to avoid thermal and voltage violations. Some of the key interfaces that may be evaluated under N-1-1 are:

- Boston Import
- Connecticut Import
- Southwest Connecticut Import

For those areas that require N-1-1 testing, each interface element may be tested as the initial facility-out condition. Other significant transmission elements may include:

- 345/115 kV transformers surrounding the interface being tested
- 345 kV lines supplying single or multiple transmission lines of the interface being tested
- 115 kV lines that are anticipated to have a significant effect on transfer capability
- Generating stations relevant to the interface being tested

Planning events and design criteria in the NERC TPL Standards, NPCC Directory #1, and ISO PP 3 will be primarily considered in determining interface planning Transfer Capability. Due to unique New England system characteristics and to be consistent with ISO operating practices, the three-phase fault with delayed clearing extreme event may be evaluated to measure system strength and determine the extent of a widespread system disturbance. Depending on the system performance as a result of an extreme event, an additional reduction in an interface planning Transfer Capability may be imposed. Also, the limit to the planning Transfer Capability of an interface may be based on Bulk Power System (BPS) testing performance.

5.4 Monitored Facilities

Elements 69 kV and above in the following areas will be monitored, as required, when conducting assessments of planning Transfer Capability:

- New England
- Maritimes
- New York
- Hydro Québec

Additional network facilities may be monitored as required.

5.5 Types of Analysis

The following types of analyses may be used when assessing planning Transfer Capability:

- Thermal Analysis
  - DC power flow analysis to determine thermally constrained transfer limits
  - AC power flow analysis to determine or verify thermally constrained transfer limits
- Voltage Analysis
  - PV analysis to determine or verify voltage constrained transfer limits
- Stability Analysis
  - Transient stability analysis to determine stability constrained transfer limits. The NPCC A-10 BPS classification test is included in this category.

Other types of analysis may be used as required.

5.6 Testing Approach

Planning Transfer Capability assessments require that a source and a sink be defined in order to adjust transfers of power across the interface of interest, from a source(s) to a sink(s). This is done by increasing generation in the source while decreasing generation in the sink. As required, various dispatch scenarios will be studied to determine the impact that specific units may have on an interface's planning Transfer Capability. Therefore, a range of PTCs may be determined and documented for certain interfaces.

Typically, complete assessments of a planning Transfer Capability adhere to the following steps:

1. Thermal analysis is first conducted on the interface under study. Pre- and post-contingency system conditions are analyzed for thermal violations as power transfers across the studied interface are increased. The initial planning Transfer Capability limit is established as a result of thermal limitations under reasonable system conditions. Other limiting thermal limits may be recorded.
2. Voltage analysis is conducted to determine if the planning Transfer Capability limit(s) found in Step 1 meets all applicable voltage limits for all tested system conditions and contingencies. The planning Transfer Capability limit(s) remains unchanged if no voltage violations are found. Other limiting system conditions may be evaluated to identify a range of voltage limits. If voltage violations are found, additional analysis is conducted in order to determine the range of power transfer at voltage limited system conditions and contingencies. The most restrictive power transfer level then becomes the planning Transfer Capability limit of the studied interface based on reasonably stressed conditions.
3. Stability analysis is conducted to determine if the planning Transfer Capability limit(s) found in Step 2 meets all applicable stability performance requirements. The planning Transfer Capability limit(s) remains unchanged if no violations of stability criteria are found. Other limiting system conditions may be evaluated to identify a range of stability limits. If violations of stability criteria are found, additional analysis is conducted in order to determine the range of power transfer at stability limited system conditions and contingencies. The most restrictive power transfer level then becomes the planning Transfer Capability limit of the studied interface based on reasonably stressed conditions. Note: stability analysis to determine the PTC of interfaces that define importing areas will not be performed.

Re-evaluation of PTCs will normally analyze the most limiting conditions unless there are planned significant transmission and/or generation changes. Therefore, this re-evaluation may only perform one or two of the three types of analysis noted above.

In cases where New England interface transfers are interdependent on other interface transfers, analyses will be conducted to obtain a region of operation that shows the interdependency of one interface planning Transfer Capability on the other. This region of operation can be translated into a range of possible planning Transfer Capabilities.

Section 6
Revision History

Rev No.	Date	Reason
2.1	01/30/2019	• Updated Section 3.1 to reflect CASPR conforming changes
2.0	05/18/2018	• Converted document to new ISO report template • Updated document to conform with ISO style guide • Re-organized document structure to align with Technical Guide structure • Updated guide to reflect changes to terminology associated with Price Responsive Demand (PRD) • Content reviewed and updated for current practices/processes
1.0	09/01/2016	• Latest revision of Appendix I of Technical Guide
0.0	02/20/2013	• Original Methodology