ISO NEW ENGLAND PLANNING PROCEDURE NO. 9

MAJOR SUBSTATION BUS ARRANGEMENT REQUIREMENTS AND GUIDELINES

EFFECTIVE DATE: September 15, 2017

TABLE OF CONTENTS

1. INTRODUCTION

This Planning Procedure provides requirements and guidance for design of substation[1] arrangements that support and promote the reliability of the New England Transmission System. This Planning Procedure provides a basic design that is readily expandable and simplifies substation switching to safely isolate facilities and equipment with minimum adverse impact on power flows. The design also provides operating flexibility that allows for efficient and effective maintenance of substation equipment, provides for a safe working environment, and is cost effective.

This Planning Procedure is broken into two sections: “Requirements” and “Guidelines.” The “Requirements” section includes mandatory standards for the layout of new Major Substations, the addition of new transmission elements at existing Major Substations, and the installation of new Independent Pole Tripping (IPT) breakers. The items in the “Guidelines” section, while not mandatory, are recommended for the purposes of future substation maintenance and expansion.

2. PURPOSE

This Planning Procedure provides arrangement requirements and guidelines for Major Substations, as defined in Appendix A of this Procedure, and the IPT requirements for new breakers. This Planning Procedure is to be applied to substation buses that are part of the Pool Transmission Facilities (PTF) operated at 115 kV or above.

This Planning Procedure specifies substation arrangements that are considered reliable and Good Utility Practice. In specific cases, alternate substation arrangements may be proposed and accepted. Requirements for the acceptability of alternative designs are described in Requirement 1 of this Planning Procedure.

These guidelines and requirements are not intended to be used as a justification to redesign existing substations not undergoing Significant Modifications. However, this procedure does not prohibit existing stations from being redesigned to meet these guidelines and requirements in the event of a non-Significant Modification. Additions to existing substations that do not constitute Significant Modifications are addressed in Requirements 5 and 6, and requirements for new circuit breakers (whether installed as part of a Significant Modification or not) are covered in Requirement 7. All other Requirements apply only to substations that are new or undergoing a Significant Modification.

In addition to the requirements and guidelines in this Planning Procedure, other North American Electric Reliability Corporation (NERC), Northeast Power Coordinating Council (NPCC), and

[1] Throughout this Planning Procedure, the term “substation” is used to refer to any facility at which transmission elements terminate, whether it contains equipment operated at multiple voltage levels (typically referred to as a “substation”) or only at a single voltage level (typically referred to as a “switching station”).

ISO New England documents may include other requirements on substation design or substation equipment. For example, ISO New England Operating Procedures 18 and 22 may need to be consulted when designing a new or Significantly Modified substation. Meeting the requirements set forth in this document does not assure that criteria in other NERC, NPCC, or ISO New England documents have been met.

3. REQUIREMENTS

1. The design for a new or Significantly Modified Major Substation shall be a breaker-and-a-half arrangement. Equipment to be operated at voltages of 345 kV or above shall be arranged with space provisions for a series breaker in the center of each bay; no such requirement shall exist for equipment that will be operated at a voltage below 345 kV. This requirement only applies to Major Substations, as defined in Appendix A of this Procedure.

   When the breaker-and-a-half design described above is infeasible due to unavoidable land availability constraints or excessive cost, other layouts, such as breaker-and-a-third or double-breaker/double-bus, may be permissible. In order for an alternative substation layout to be used, the proponent of the proposed layout must submit a written statement to ISO New England explaining the need to use an alternative layout, and ISO New England must review and approve the suggested alternative layout. Any alternative substation layout must perform comparably to a breaker-and-a-half layout with respect to conditions with elements (including circuit breakers and buses) out of service. Specifically, any alternative layout at Major Substations shall meet the following performance requirements:

   - Clearing a fault on a Key Transmission Element shall not require the opening of a terminal of any other Key Transmission Element (unless a breaker failure also occurs).
   - With all elements in service, clearing a fault on a bus section within the substation shall not result in the opening of a terminal of any more than one Key Transmission Element.
   - With all elements in service, a fault followed by the failure of any circuit breaker within the substation shall not result in the opening of terminals of any more than two Key Transmission Elements.
   - With all elements in service, the opening of any single circuit breaker shall not open a terminal of a Key Transmission Element, and shall not split the substation into two isolated portions with no direct connection between them at the substation.

- With one circuit breaker open, opening a second circuit breaker or clearing a fault on any element shall not split the substation into two or more isolated portions with no direct connection between them at the substation. This requirement shall not prohibit the disconnection of a single bay of a breaker-and-a-half, breaker-and-a-third, or similar design by opening two breakers in a single bay.

A ring bus or straight bus design will not meet the requirements listed above, and as such shall not be a permissible design for a new or Significantly Modified Major Substation.

2. If a series breaker is installed in the center of a bay in a breaker-and-a-half substation, another transmission element shall not be terminated between the pair of series breakers. Therefore, the required space provision for the series breaker at 345 kV or above (as described in Requirement 1), and any space provision for a series breaker at voltages below 345 kV, should leave sufficient space for the series breaker only, and not for termination of an additional transmission element. No isolating disconnect switches need to be installed between the two series breakers in the center of a breaker-and-a-half bay.

3. Any Key Transmission Element, as defined in Appendix A of this Procedure, shall terminate in a designated bay position of a breaker-and-a-half configuration. Additionally, any 345 kV transmission line (whether radial or not) shall terminate in a designated bay position of a breaker-and-a-half configuration. Key Transmission Elements and 345 kV transmission lines at new or Significantly Modified non-breaker-and-a-half stations shall terminate according to the performance requirements in Requirement 1.

   Considerations for terminating Key Transmission Elements in a breaker-and-a-third configuration are the same as for breaker-and-a-half configurations, with one exception. At 115 kV breaker-and-a-third substations, 345/115 kV or 230/115 kV transformers may be terminated directly on a 115 kV bus, since additional transformers may be terminated in a bay without a common breaker between any two transformers.

4. Non-Key Transmission Elements may either be terminated in a designated bay position or on a main bus of a breaker-and-a-half configuration. The following are examples of non-Key Transmission Elements that may be terminated in a designated bay position or on a main bus of a breaker-and-a-half configuration:

   a. A capacitor bank or set of capacitor banks

   b. A shunt reactor or set of shunt reactors

   c. A load-serving transformer or bank of load-serving transformers (e.g. 345/34.5 or 115/13.8 kV)

d. A transformer that has only one terminal operated at a voltage above 100 kV (e.g. 115/69 kV), excluding generator step-up transformers

e. A radial transmission line serving load and/or generating units smaller than 5 MW each (and a total of under 20 MW of generation), operated at a voltage below 345 kV

When non-Key Transmission Elements are terminated on a main bus of a breaker-and-a-half configuration, non-Key Transmission Elements must have their own switching device (a circuit breaker or circuit switcher that is capable of interrupting fault current) and their own protective relaying that trips this device. The faulted non-Key Transmission Element must be removed from service without disconnecting the main bus or removing it from service.

Considerations for terminating elements in a breaker-and-a-third or other alternative configuration are the same as for breaker-and-a-half.

Shunt reactors that are used to compensate for line charging may also be installed in the same bay position as the transmission line for which they are compensating, or on the transmission line itself. In this case, a separate circuit breaker, circuit switcher, or disconnect switch shall be installed to allow the reactor to be isolated from the transmission line, and the transmission line to be restored, in the event of a failure of the reactor.

5. Transmission elements added to a pre-existing breaker-and-a-half, breaker-and-a-third, or similar substation, whether constituting a Significant Modification or not, shall be added in accordance with Requirements 3 and 4 above. For a non-Significant Modification involving the addition of one or more transmission elements to a pre-existing substation that does not have a layout compliant with this Procedure, the addition of the transmission element may be consistent with the pre-existing substation's layout. When a non-Major Substation becomes a Major Substation due to a non-Significant Modification consisting of the addition of one or more Key Transmission Elements, this Requirement must be met only when the pre-existing substation has been laid out in preparation for eventual expansion to a breaker-and-a-half design.

   Exceptions to this Requirement may be granted by ISO New England, consistent with the allowance for alternative layouts in Requirement 1.

6. Shunt static and dynamic reactive devices shall not be installed on the tertiary winding of a transformer with the primary terminal and at least one secondary terminal operated at 100 kV or higher.

7. All new or replacement 345 kV circuit breakers, whether at Major Substations or other substations, shall utilize Independent Pole Tripping in order to minimize the effects of three-phase faults with breaker failures. (Breakers shall attempt to open all three phases of a transmission element for any fault on that element, but in the event of a failure of one phase to open, the two unaffected phases shall remain capable of opening.) New or replacement 345 kV breakers shall meet the requirements of Appendix B, titled "Requirements for Circuit Breakers Used for Independent Pole Tripping."

4. GUIDELINES

1. Where practical, land shall be purchased and equipment shall be arranged to allow for a non-Major Substation to be expanded to a breaker-and-a-half configuration when transmission grid expansions dictate. It is not recommended that in all cases a substation initially be built with a breaker-and-a-half bus arrangement, only that the design of the substation provides for expansion to a breaker-and-a-half bus arrangement when the substation might become a Major Substation. In cases where the substation is not expected to become a Major Substation, it is not necessary to provide land or arrange equipment for a future expansion to a breaker-and-a-half configuration.

2. When possible, the use of air-insulated bus is the recommended design for new substations. Gas-insulated bus shall be utilized when it is required to provide for a substation arrangement that conforms to the Requirements of this Procedure.

3. When designing a new substation or designing significant modifications to an existing substation, the potential for the future termination of transmission elements should be considered. For example, if there is vacant space on existing transmission rights-of-way emanating from the substation or if the substation is located in an area that is or will be deficient in generation, it may be prudent to plan the substation for additional transmission elements.

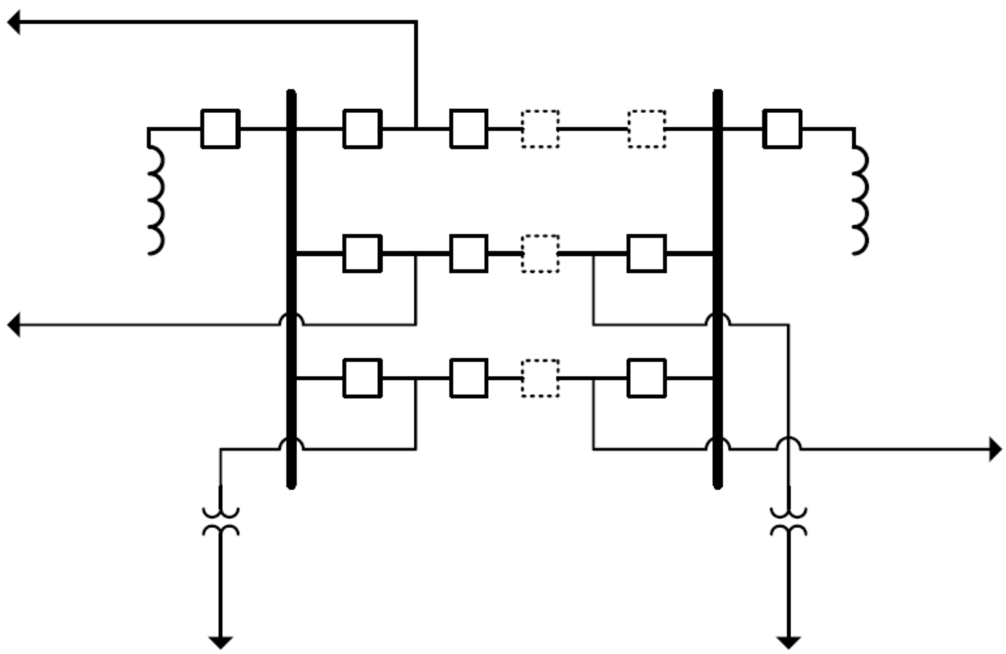
4. Where the failure of a circuit breaker in the center of a breaker-and-a-half bay produces unacceptable operational consequences or violations of planning criteria, a series breaker with no switches between breakers can be added if reconfiguration of the interconnecting elements increases cost or reduces reliability.

5. When choosing the arrangement of transmission elements within a substation, consideration should be given to the effects of various contingencies with circuit breakers out of service (open) for maintenance or due to a contingency. For example, the contingent loss of a transmission element may split a substation into two disconnected parts if another breaker is out of service. When possible, substations should be arranged in a manner that minimizes the possible negative impacts of these contingency pairs.

6. When a new or Significantly Modified Major Substation is designed and built, compliance with the protection system requirements in NPCC Directory 4 is strongly recommended. While two independent protection schemes are recommended, the NPCC Directory 1 Implementation Plan requirement for two high-speed protection schemes on every BPS element does not need to be observed unless the substation is classified as a part of the Bulk Power System.

5. SAMPLE SUBSTATION LAYOUT

The sample substation shown below demonstrates the layout required by this Procedure. Substation components shown with dashed lines, including series breakers in the center of each bay, represent space for future elements, which will not need to be installed when the station is initially constructed unless required as described in Guideline 4. For a substation operated at a voltage below 345 kV, the provision of space for the series breaker in the center of each bay would not be required.



6. DOCUMENT HISTORY[2]

Rev. 0	App.: RTPC,
Rev. 1	Rec.: RC – 4/15/08, Rec.: PC – 5/9/08, Eff.: 5/12/08
Rev. 2	Rec.: RC – 8/24/17; Rec.: PC – 9/15/17, Eff.: 9/15/17

[2] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

APPENDIX A
DEFINITIONS

The following terms are defined for the purposes of this Planning Procedure only. Any capitalized term not defined herein is defined in the ISO New England Transmission Markets, and Services Tariff, section I.2.2.

Key Transmission Element: Any one of the elements on the following list:

- AC transmission lines that are designated as Pool Transmission Facilities
- HVDC transmission facilities
- Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher
- Phase-shifting transformers
- Synchronous condensers
- FACTS devices such as SVCs or STATCOMs
- Generator step-up transformers
- AC transmission lines that connect one or more individual generating units of over 5 MW in size, or a total of over 20 MW of generation, to the Pool Transmission Facilities

When multiple elements are operated in parallel without independent protection systems (for example, two transformers or two underground cables placed in parallel to achieve higher ratings or lower impedance), the set of parallel elements shall be considered a single Key Transmission Element.

Major Substation: A substation that interconnects five or more Key Transmission Elements, or is expected to do so in the future.

Significant Modification: The complete replacement of all equipment at a single voltage level within a substation, possibly (but not necessarily) including relocation to another physical site. The addition of any number of transmission elements to a substation where some existing equipment remains intact shall not be considered a Significant Modification.

APPENDIX B
REQUIREMENTS FOR CIRCUIT BREAKERS USED FOR INDEPENDENT POLE TRIPPING

DEFINITION OF INDEPENDENT POLE TRIPPING

ISO New England uses the definition of independent pole tripping from IEEE Standard Definitions for Power Switchgear, Standard C.37.100-1992. The definition is:

INDEPENDENT POLE TRIPPING – The application of multipole circuit breakers in such a manner that a malfunction of one of more poles or associated control circuits will not prevent successful tripping of the remaining pole(s).

Notes:

1. Circuit breakers used for independent pole tripping must inherently be capable of independent pole opening.
2. Independent pole tripping is applied on ac power systems to enhance system stability by maximizing the probability of clearing at least some phases of a multiple phase fault.

INDEPENDENT POLE TRIPPING BREAKER CLASSIFICATION

To be classified as an independent pole tripping (IPT) breaker in New England, a circuit breaker must have the following specific features:

1. The circuit breaker <u>must</u> have no common ties (mechanical, pneumatic, or hydraulic) between poles that make automatic tripping of any pole dependent upon automatic tripping of another pole. A breaker may have common ties between poles for closing operations ("gang closing") if the independent pole tripping is not compromised. A breaker may have common ties between poles, such as manual tripping devices, and still be considered IPT.

2. Dual trip coils <u>must</u> be provided for each operating mechanism, as required in NPCC Reliability Reference Directory #4, Bulk Power System Protection Criteria, December 01, 2009, which states, "No single trip coil failure shall prevent both independent protection groups from performing the intended function. The design of a breaker with two trip coils shall be such that the breaker will operate if both trip coils are energized simultaneously. The correct operation of this design shall be verified by tests."

3. Each pole of the circuit breaker <u>must</u> be furnished with at least one, and preferably two or more, auxiliary switches. When two auxiliary switches are furnished, they should be driven as independently as possible. When two auxiliary switches are available, contacts

from one auxiliary switch should be used in one protection circuit; contacts from the second auxiliary switch should be used in the other protection circuit used to protect the same element.

Auxiliary contacts from each pole, connected in series or parallel groups, must be used in breaker internal control circuits. The series and parallel contact groups must be applied in such a way that the failure of a single auxiliary switch or auxiliary switch contacts will not result in the failure to trip of more than one pole in response to a protective relay operation. Auxiliary contacts from all three poles of a circuit breaker must be used in all control and protective relay circuits in which the failure of a single auxiliary contact to perform correctly would result in the inability of any protective relay system to trip in response to a protective relay operation.

4. For circuit breakers that use series pressure switch contacts either to block tripping of to initiate tripping, dual pressure switches, one for each trip circuit, must be supplied. If one or both of the pressure switches utilizes an auxiliary relay, each pressure switch/auxiliary relay combination must receive dc from its respective trip circuit supply.