**CENTRAL MAINE POWER COMPANY**
**RESPONSE TO EXAMINER'S DATA REQUEST NO. 4**
**DOCKET No. 2008-255**

October 28, 2008

**EX-04-09**

**Q.** (Volume VII, Exhibit 1-1, Page 15 of 573) Please explain why you use 30 minutes to adjust system conditions prior to the next contingency where the standards use 10 minutes.

**A.** Following the first contingency, this planning assumption is aligned with the operating criterion which allows 30 minutes to adjust to the next contingency. Please refer to ISO-NE Transmission Operating Procedure #19, provided as Attachment 1.

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**Attachment(s):**
1. ISO-NE Transmission Operating Procedure #19

ISO new england

# Operating Procedures

ISO New England Operating Procedure No. 19

*Transmission Operations*

Effective Date: April 13, 2007
Revision No. 4

# ISO New England Operating Procedure No. 19
# Transmission Operations

Effective Date: April 13, 2007

REFERENCES:

1. NPCC Basic Criteria for Design and Operation of Interconnected Power Systems
2. NPCC Emergency Operation Criteria
3. Capacity Rating Procedures - System Design Task Force
4. Master/Local Control Center Procedure No. 2 - Abnormal Conditions Alert (M/LCC 2)
5. ISO New England Operating Procedure No. 4 - Action During a Capacity Deficiency (OP 4)
6. ISO New England Operating Procedure No. 7 - Action In an Emergency (OP 7)
7. ISO New England Operating Procedure No. 8 - Operating Reserve and Regulation (OP 8)
8. ISO New England Transmission Operating Guides
9. ISO New England Operating Procedure No. 3 - Transmission Outage Scheduling (OP 3)

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APPENDICES:

## I. INTRODUCTION

This Operating Procedure describes reliability criteria for the analysis and operation of the New England Transmission System. The provisions contained herein are intended to be in accordance with Northeast Power Coordinating Council Inc. (NPCC) and ISO New England Operating Procedures listed as references for this document. Prescribed operator actions are further detailed in several ISO New England Transmission Operating Guides.

The provisions in this document are used to determine data, methods and limits for operation of the New England Transmission System (69 kV and above). The ISO and Local Control Centers use these data, methods and limits to operate the transmission system in accordance with this procedure.

Appendix F contains a summary of OP 19 Transmission Operations Procedure.

## II. RELIABILITY CRITERIA FOR TRANSMISSION OPERATIONS

The New England Transmission System is operated so that the most severe single contingency can be sustained without causing:

- Equipment damage due to thermal overload,
- Cascading thermal overloads,
- Excessively high or low voltage or voltage collapse,
- Unit or area instability,
- Undamped oscillations.

Any single contingency should not cause the loss of other critical facilities or portions of the bulk power system. Single contingencies within the New England Control Area should not result in violation of neighboring Areas' operating reliability criteria.

Two levels of transmission reliability are prescribed and define the condition of the bulk power system. During NORMAL (non-stressed) Conditions, the higher level of prescribed reliability is maintained. During stressed or EMERGENCY Conditions, a lower level of reliability is permitted to allow for increased operating flexibility and to minimize the impact on customers during power system emergencies.

Actions should be taken to establish and maintain NORMAL Conditions. Regular cycling between NORMAL and EMERGENCY Conditions should be avoided. Operations and Operations Planning should not intentionally position daily operations into EMERGENCY Conditions. Capacity deficiencies or the occurrences of multiple contingencies are some reasons why EMERGENCY Conditions might exist.

This Operating Procedure includes specific definitions and criteria for the two levels of reliability. Appendix A contains a flow chart that summarizes the methods and criteria contained in this document and provides an overview of its structure. Appendix B provides definitions of thermal capacity ratings for transmission facilities [NORMAL, Long Time Emergency (LTE), Short Time Emergency (STE) and Drastic Action Limit (DAL)].

## A. Normal Conditions

The highest level of transmission reliability is achieved during non-stressed or NORMAL Conditions on the bulk power system. In general, this level of reliability is accomplished by satisfying NORMAL Criteria for a wide range of contingencies (NORMAL Contingencies) using a limited set of operator actions (NORMAL Actions). More specifically, for all stability related and Inter-Area thermal and voltage/reactive operations, all seven NORMAL Contingencies (in Section II.A.2.a-g) are applicable. For thermal and voltage/reactive operations within the New England Control Area that do not jeopardize the reliability of Areas outside New England, NORMAL Contingencies in Section II.A.2.f-g (loss of two circuits on a multiple circuit tower and loss of a single element with delayed clearing) and a permanent three-phase fault on a bus section described in Section II A.2.a. are not considered. This approach is consistent with the NPCC criteria philosophy that the basic criteria are not necessarily applicable in the portions of a member system where instability or overloads will not jeopardize the reliability of the bulk power system. The following sections describe these NORMAL Criteria, NORMAL Contingencies and NORMAL Actions.

1. Normal Criteria

   a) Generation and transmission service is scheduled to provide the New England Control Area load and operating reserve as prescribed in OP 8 while covering NORMAL Contingencies.

   b) Pre-contingency loadings of transmission facilities should not exceed NORMAL ratings. Allowances can be made for scheduled switching activities that are typically completed within 15 minutes in accordance with OP 3.

   c) NORMAL Contingencies should not cause, or result in, loadings beyond STE ratings. Flows between LTE and STE must be reduced to or below LTE as soon as possible and definitely within 15 minutes. If studies show that operators would not be able to reduce flows to or below LTE within 15 minutes, action should be taken (if possible) such that NORMAL Contingencies would not cause, or result in, loadings above LTE ratings.

      Previously established/provided DAL ratings may be used but only if authorized by the Transmission Owner whose transmission facilities would be affected and flows between STE and DAL can be reduced to or below LTE immediately and definitely within 5 minutes.

   d) Without prior approval to operate to STE ratings, NORMAL Contingencies should not cause, or result in, loadings on New York ISO (NYISO) transmission facilities, including NYISO-the New England Control Area tie lines, beyond LTE ratings.

Underground cable circuits may be post contingency loaded to STE ratings provided generation and/or phase angle regulation are available to reduce the loadings to LTE ratings within 15 minutes and provided no other NYISO facility is loaded beyond its LTE rating. The 1385 Norwalk Harbor-Northport 138 kV cable and the CONED-PSE&G tie lines, which are cable circuits, are not included in this exception.

e) NORMAL Contingencies should not cause instability, unacceptably high or low voltage or voltage collapse.

f) Any automatic reclosing and subsequent manual reclosing before adjusting generation should not cause instability of the transmission system.

2. Normal Contingencies

For all stability related and inter-Area operations, protection should be provided for ALL of the NORMAL Contingencies listed in a-g below.

For thermal and voltage/reactive operations within the New England Control Area, protection should be provided for the NORMAL Contingencies listed in a-e below with the exclusion of a permanent three-phase fault on a bus section (part of Section II.A.2.a.).

During typical conditions with all major transmission facilities in-service, NORMAL Contingencies f, g and a permanent three-phase fault on a bus section (part of Part of Section II.A.2.a.) should be covered in thermal and voltage/reactive operations if the occurrence of these contingencies could jeopardize the reliability of Areas outside of New England. (Appendix C lists stuck breaker contingencies and Appendix D lists double circuit tower line contingencies. Appendix G documents the procedure to be followed in determining if a stuck breaker contingency would have unacceptable Inter-Area impact. Appendix H provides a list of actions that may be utilized to reduce the cost of providing stuck breaker protection. Appendix I lists bus fault contingencies that can have unacceptable inter-Area impacts or cause single or multi-Generator instability).

During less frequent conditions when a major transmission facility is out-of-service NORMAL contingencies (f) and (g) need not be covered if the outage substantially reduces transfer limits based on NORMAL Contingencies f and g.

During less frequent conditions when a major transmission facility is out-of-service, a permanent three-phase fault on a bus section (part of Section II A.2.a.) should be covered for thermal and voltage/reactive operations if the occurrence of this contingency could jeopardize the reliability of Areas outside of New England, and for single or multi-unit instability resulting from this contingency.

a) A permanent three-phase fault on any Generator, transmission circuit, transformer or bus section with normal fault clearing.

b) Loss of any element without a fault.

c) A permanent phase to ground fault on a circuit breaker with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.)

d) Simultaneous permanent loss of both poles of a direct current bipolar facility without an AC fault.

e) The failure of a circuit breaker associated with an SPS to operate when required following: loss of any element without a fault; or a permanent phase to ground fault, with normal fault clearing, on any transmission circuit, transformer or bus section.

f) Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and, therefore, can be excluded. Other similar situations can be excluded on the basis of acceptable risk following appropriate Northeast Power Coordinating Council acceptance of each specific exclusion (Appendix D lists 345 kV multiple circuit towers in the New England Control Area).

g) A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing. (Delayed fault clearing is consistent with correct operation of a breaker failure scheme and its associated breakers, or of a backup relay scheme with an intentional time delay.)

3. Normal Actions

The ISO and Local Control Centers will continuously assess system conditions and implement the NORMAL Actions described below to maintain or restore transmission reliability to NORMAL Conditions.

a) Actions For Contingencies That Affect Small/Local Areas Within the New England Control Area

If a contingency will impact only a small/local area within the New England Control Area, the following NORMAL Actions should be implemented as required:

ISO initiated deviation from economic dispatch (notify appropriate Local Control Center)

- If the local area can be protected by deviation from economic dispatch, the ISO and Local Control Centers will provide such protection.

Transmission Owner waiver of contingency protection

- If a local area cannot be protected by deviation from economic dispatch, Transmission Owner may elect to waive contingency protection for the local area. When the local area involves two or more Transmission Owners, the appropriate Local Control Center will inform one of the involved Transmission Owners of the specific operating conditions. All coordination required with other impacted Transmission Owners to waive contingency protection for the local area is the responsibility of the Transmission Owner first contacted by the Local Control Center. All waivers granted under this provision must be communicated to the ISO electronically at the time that the waiver is granted.

When the local area involves more than one Local Control Center, one of the Local Control Centers will be designated to contact an involved Transmission Owner who will then follow the process outlined above.

b) Use of Special Protection Systems or the Preplanned Opening of Circuit Breakers.

(1) Where Possible, Arm Special Protection Systems.

(2) Manually set up tripping of Generator or Resources with pump storage capability. This preplanned option of opening circuit breakers is limited to situations where previously documented studies have demonstrated that such breaker openings reliably mitigate the specific existing operating conditions and do not result in the loss of single contingency protection for other contingencies/facilities.

c) Weather Sensitive Transmission Facility Ratings

There are times when actual ambient conditions (temperatures and wind) are significantly different from those used to establish standard seasonal ratings. During those times, the use of temporary ratings based on actual ambient conditions may be warranted. Depending on the ambient conditions, the temporary ratings may be higher or lower than the standard seasonal ratings. When such weather conditions exist and a transmission facility is limiting, The ISO, the appropriate Local Control Center or appropriate Transmission Owner will identify the need for a temporary transmission facility rating based on actual weather conditions. In cases where the Transmission Owner has supplied pre-defined weather sensitive ratings, such ratings will be used by the ISO and the Local Control Center after the Local Control Center and/or Transmission Owner has gathered/established the actual weather conditions. If pre-defined weather sensitive ratings are not available, the involved Transmission Owner will be informed of the circumstances. That Transmission Owner may elect to provide the appropriate Local Control Center with temporary ratings along with any pertinent qualifications for their use. The Local Control Center will forward all temporary rating information electronically to the ISO. Such temporary ratings will then be used in operations for the time period specified by the Transmission Owner or until rescinded by the Transmission Owner.

d) Deviation from Economic Dispatch

Deviate from economic dispatch and schedule Resources to maintain NORMAL transmission reliability. The ISO or appropriate Local Control Center may implement M/LCC 2 to declare an abnormal conditions alert if necessary.

e) *Switch Transmission Circuits*

Open or close circuits to relieve transmission constraints. This action can only be implemented when authorized by the ISO and when previously documented studies have demonstrated that such circuit openings reliably relieve the specific existing conditions and do not result in the loss of protection for other contingencies/facilities.

f) OP 4 Actions 1 through 11

Implement selected actions from OP 4, Actions 1 through 11. These Actions utilize Generator maximum capabilities, Demand Response Loads, voluntary load curtailment of Market Participant's facilities, capacity/energy purchases, contracted customer generation and depletion of 30 minute reserve.

## B. Emergency Conditions

The system is in an EMERGENCY Condition if NORMAL Criteria is violated. A lower level of reliability is permitted when operating under EMERGENCY Conditions provided that all appropriate NORMAL Actions have been initiated to restore NORMAL Criteria. This level of reliability meets EMERGENCY Criteria for a less stringent set of contingencies (EMERGENCY Contingencies) using EMERGENCY Actions. Exposure to reliability levels below EMERGENCY Conditions should not exist for more than 30 minutes.

1. Emergency Criteria

   a) Generation and transmission facilities are adequate to supply the New England Control Area load and at least minimum reserve requirements (10 minute requirements) as prescribed in OP 8 while covering only EMERGENCY Contingencies.

   b) Pre-contingency facility loadings may be between NORMAL and LTE if EMERGENCY Contingencies would not cause loadings beyond LTE ratings. Loadings should be returned to or below the NORMAL rating after the daily load cycle.

   c) EMERGENCY Contingencies should not cause loadings beyond STE ratings. Flows between LTE and STE must be reduced to or below LTE as soon as possible and definitely within 15 minutes. Automatic devices (SPS), switching to set up a facility to trip upon occurrence of a specific contingency or preplanned post-contingency operator responses are required if DAL ratings are used.

   d) EMERGENCY Contingencies should not cause instability, unacceptably high or low voltage or voltage collapse.

   e) Any automatic reclosing should not cause instability of the transmission system.

2. Emergency Contingencies

   a) A permanent three-phase fault on any Generator, transmission circuit, transformer or bus section, with normal fault clearing.

   b) The loss of any element without a fault.

3. Emergency Actions

   EMERGENCY Actions should be taken to maintain or restore power system conditions to at least those prescribed for operations under EMERGENCY Conditions. In general, all appropriate and timely NORMAL Actions should be exhausted before taking EMERGENCY Actions. EMERGENCY Actions should be taken before NORMAL Actions if the NORMAL Actions cannot be completed in time to relieve a thermal overload above LTE, prevent voltage collapse, or restore protection for EMERGENCY Contingencies within 30 minutes. Any unused long term NORMAL Actions should be taken to allow for the cancellation of EMERGENCY Actions.

a) Transmission Circuit Switching

In very well defined situations where it is clear that opening a transmission facility will alleviate a problem existing for a specific emergency situation, consideration will be given to opening such facility. This action, without pre-determined studies, documentation, and authority will only be initiated to prevent more severe EMERGENCY Action and must be reported immediately to the Transmission Owner.

b) OP 4 and OP 7

OP 4 and OP 7 EMERGENCY Actions include:

OP 4 - Action 12 and 13; 5% voltage reduction, requiring more/less than 10 minutes.

OP 4 - Action 14 and 15; customer generation not contractually available to ISO. Voluntary load curtailment by large industrial and commercial customers. Radio and TV appeals for voluntary load curtailment. Voluntary load curtailment by customers.

OP 4 - Action 16; Request New England state Governors to reinforce appeals for voluntary load curtailment.

OP 7; Load shedding.

The following sections provide more detail on when it would be appropriate to take EMERGENCY Actions.

c) Pre-Contingency Emergency Actions

EMERGENCY Actions may be needed to meet EMERGENCY Criteria even though a contingency has not occurred. Such pre-contingency EMERGENCY Actions will be taken when NORMAL Actions are exhausted or can not be completed in a timely manner and there would be insufficient time after an EMERGENCY Contingency to contain the impact to a small/local area. Pre-contingency EMERGENCY Actions are to be initiated when a potential EMERGENCY Contingency threatens large portions of the New England Control Area load or could possibly cause a split of the bulk power system due to post-contingency voltage collapse, rapid cascading thermal overloads or, system instability. Pre-contingency EMERGENCY Actions should also be taken when a potential EMERGENCY Contingency poses the same threats to Areas outside of New England or jeopardizes the reliability of the Northeast Interconnection.

Shift operators are responsible to keep appropriate Supervisors at the ISO and Local Control Centers advised as to conditions that might necessitate management review of the need to implement EMERGENCY Actions on a pre-contingency basis.

Management at the ISO and at the Local Control Centers, to the extent that time permits, should consult with affected Transmission Owners when developing pre-contingency strategies.

d) Planned Immediate Post-Contingency Emergency Actions

If an EMERGENCY Contingency does not risk system stability but would result in low or gradually declining voltages or thermal loadings between STE and DAL, specific voltage reduction or load shedding plans should be established before the contingency for implementation immediately after the contingency. Post-contingency EMERGENCY Action should be established and coordinated with the Local Control Centers before the need for implementation arises. If automatic devices are being used, their actions should be completed in a matter of cycles or seconds after the contingency. Manual actions should be completed as soon as possible after the contingency (seconds if possible) but definitely within the one-two minutes required to prevent voltage collapse or cascading thermal overloads. Post-contingent circuit loadings between STE and DAL must be reduced below LTE immediately and definitely within five (5) minutes.

## C. POST-CONTINGENCY OPERATION

If a contingency involves the loss of a transmission circuit(s), operators should attempt to reclose the circuit(s) within 5 minutes unless otherwise specified in specific policies and/or procedures. If reclosure is successful, the system should be back to its original state and normal operation should resume. If reclosure is unsuccessful or the contingency involved the loss of generation or load, operators should assess system conditions and perform appropriate NORMAL and EMERGENCY Actions to restore NORMAL and EMERGENCY Conditions. When possible, coverage for NORMAL Contingencies should be restored using NORMAL Actions.

*Post-contingency Actions should meet the following time requirements:*

- Rapidly declining critical transmission voltages should be stabilized as quickly as possible (within one-two minutes) using pre-determined EMERGENCY Actions, including voltage reduction and/or load shedding.

- Post-contingent transmission facility loadings between STE and DAL should be reduced below LTE immediately and definitely within 5 minutes using pre-defined EMERGENCY Actions including voltage reduction and/or load shedding plans.

- Post-contingent transmission facility loadings between LTE and STE ratings should be reduced below LTE as soon as possible and definitely within 15 minutes using appropriate NORMAL and/or EMERGENCY Actions.

- Coverage for EMERGENCY Contingencies should be restored within 30 minutes using appropriate NORMAL and/or EMERGENCY Actions.

## III. TRANSMISSION SYSTEM ANALYSIS

### A. Scope of Analysis

Transmission system analysis is required to:

- Identify significant contingencies and system conditions during which contingencies can adversely impact system operation and;

- Develop data, methods, operating guidelines and procedures which, when implemented, will provide reliable operation of the bulk power system per the criteria in this document.

Short term thermal analysis is performed on a continuous basis and coordinated with appropriate Local Control Centers and adjoining NPCC Areas. Long term thermal analysis is done on a seasonal, annual or as required basis and is coordinated with appropriate Transmission Owners, Local Control Centers, adjoining NPCC Areas and Task Forces.

Long term stability studies are reviewed with the Stability Task Force and appropriate Inter-Area study groups. Short-term stability analysis is coordinated with individual Transmission Owner representatives on the Stability Task Force.

Short-term voltage/reactive analysis is reviewed with appropriate Local Control Centers and NPCC Areas. Longer-term voltage/reactive analysis is reviewed with the Voltage Task Force and other appropriate Task Forces or Inter-Area study groups.

### B. Classifying System Responses to Contingencies

Contingencies fall into one of the following categories depending on their impact on system reliability:

1. Contingencies Critical to Areas External to New England

   This type of contingency either involves the loss of an inter-Area transmission facility (thereby reducing inter-Area transfer capability) or has more severe consequences on an external Area than the most severe contingency in the external Area. The possibility of thermal overloads, excessive voltage drops, or undamped oscillations on the interconnection should be considered when assessing the impact of these contingencies. These contingencies are critical to interconnected system reliability.

2. Contingencies Critical to Large Areas of the New England Control Area or Bulk Power Transfers within the New England Control Area

   This type of contingency can threaten large areas within the New England Control Area in two ways. In one case, the contingency could split an area away from the bulk power transmission system due to cascading thermal overloads, voltage collapse or system instability. Further breakup would likely occur in the islanded area. The remaining bulk power system would be left with a substantial deficiency or excess of power. In the other case, the contingency could cause the loss of another critical transmission facility, thereby significantly reducing transfer capability on the bulk power system and seriously impairing the ability to serve customer load. These contingencies are critical to the New England Control Area transmission reliability.

3. Contingencies that Affect Small/Local Areas within the New England Control Area

   This type of contingency affects only a relatively small area within the New England Control Area and does not impair reliability of the bulk power system. The ISO will provide contingency protection, if possible, by deviating from economic dispatch. Otherwise, the Transmission Owner (s) involved will be contacted through the appropriate Local Control Center. The Transmission Owner (s) may elect to grant a waiver of contingency coverage. Multiple Transmission Owner waivers of first contingency protection require one of the affected Transmission Owners to communicate and coordinate waiver action with all other affected Transmission Owners.

### C. Extreme Contingencies

Recognizing that the bulk power system can be subject to events that are more severe than NORMAL or EMERGENCY Contingencies, EXTREME Contingencies will be assessed to determine their effect on system performance. After due analysis and assessment of EXTREME Contingencies, Transmission Owners may utilize measures, where appropriate, to reduce the frequency of occurrence or to mitigate the circumstances that are indicated as a result of testing for such contingencies.

Appendix E lists the EXTREME Contingencies to be considered.

## OP 19 REVISION HISTORY

**Document History** (This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well revisions made to the ISO New England Procedure subsequent to the RTO Operations Date.)

| Rev. No. | Date | Reason |
|---|---|---|
| Rev 1 | 07/22/98 | |
| Rev 2 | 02/01/05 | Updated to conform to RTO |
| Rev 3 | 02/03/06 | Updated to clarify actions taken in OP 3 for scheduled switching activities that are typically completed within 15 minutes |
| Rev 4 | 04/13/07 | Incorporated Appendix I for Bus Faults and made language clarifications |
| | | |