Policy 6 – Operations Planning

Version 2, Draft 7

For standing committees' ballot.

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Policy Subsections

A. Normal Operations
B. Emergency Operations
C. Load Shedding
D. System Restoration
E. Continuity of Operations

Same sections. (C. re-titled)

Introduction

Each OPERATING AUTHORITY shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each OPERATING AUTHORITY is responsible for using available personnel and system equipment to implement these plans to assure that interconnected systems reliability will be maintained.

SYSTEM OPERATORS shall participate in the system planning and design study processes so that these studies will contain the SYSTEM OPERATORS' perspective and the SYSTEM OPERATORS will know the intended planning purpose.

A. Normal Operations

Many of the "guides" in current version of Policy 6 were brought into the Requirements section. Also added interrelationships between Operating Authority and Reliability Coordinator that is missing in current Policy 6.

Requirements

1. **Operations planning coordination.** Each OPERATING AUTHORITY shall plan its current-day, next-day, and seasonal operations in coordination with neighboring OPERATING AUTHORITIES so that normal INTERCONNECTION operation will proceed in an orderly and consistent manner.

1.1. Each transmission and generation owner shall coordinate its current-day, next-day, and seasonal operations with its host CONTROL AREA(s).

1.2. Each CONTROL AREA shall coordinate its current-day, next-day, and seasonal operations with neighboring CONTROL AREAS and with its RELIABILITY COORDINATOR.

New.

2. **Operations planning objectives.** Each OPERATING AUTHORITY shall plan to meet:

2.1. Planned changes in system configuration, generation dispatch, interchange scheduling and demand patterns.

2.2. Unplanned changes in system configuration and generation dispatch (at a minimum N-1 CONTINGENCY planning) in accordance with NERC, Regional, and local reliability requirements.

2.3. Capacity and energy reserve requirements, including the deliverability/capability for any single CONTINGENCY.

2.4. Voltage and/or reactive limits, including the deliverability/capability for any single CONTINGENCY.

2.5. INTERCHANGE SCHEDULES. All generator owners shall operate their plant so as to adhere to ramp schedules.

2.6. SYSTEM OPERATING LIMITS.

3. **BULK ELECTRIC SYSTEM studies.** The CONTROL AREA shall perform seasonal, next-day, and current-day BULK ELECTRIC SYSTEM studies to determine SYSTEM OPERATING LIMITS. Neighboring CONTROL AREAS shall utilize identical SYSTEM OPERATING LIMITS for common facilities. These BULK ELECTRIC SYSTEM studies shall be updated as necessary to reflect current system conditions. The results of BULK ELECTRIC SYSTEM studies shall be made available to the CONTROL AREA operators and to its RELIABILITY COORDINATOR.

4. **Total Transfer Capability or Available Transfer Capability and transmission coordination.** The CONTROL AREA shall include known SOLs or IROLs within its area and neighboring areas in the

determination of transfer capabilities, in accordance with filed tariffs and/or regional TTC/ATC calculation processes.

5. **Generator capability.** At the request of the CONTROL AREA, generator operators shall perform generating capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the CONTROL AREA operator as requested. (See also Planning Standard II.B.S1)

6. **Communication of facility status.** (Note: in the following Requirements, the term "immediately" shall be defined as "without any intentional time delay.")

6.1. Generator operators shall immediately notify their CONTROL AREA operators of changes in capabilities and characteristics including but not limited to:

6.1.1. Changes in real and reactive output capabilities,

6.1.2. Automatic Voltage Regulator status and mode setting

6.2. Generation operators shall provide a forecast of expected real power output to their CONTROL AREAS to assist in operations planning at the CONTROL AREA'S request (e.g. a seven-day forecast of real output).

6.3. Transmission operators shall immediately notify their CONTROL AREA operators of changes in capabilities and characteristics including but not limited to:

6.3.1. Changes in transmission facility status

6.3.2. Changes in transmission facility rating

6.4. CONTROL AREA shall immediately communicate the above information to their RELIABILITY COORDINATOR.

6.5. **Uniform line identifiers.** Neighboring OPERATING AUTHORITIES shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

7. **Computer models.** The CONTROL AREA shall maintain accurate computer models utilized for analyzing and planning system operations.

B. Emergency Operations

Many "guides" moved to Requirements.

Introduction

Each OPERATING AUTHORITY shall develop, maintain, and implement a set of plans consistent with NERC Operating Policies to mitigate operating emergencies. These plans shall be coordinated with other OPERATING AUTHORITIES, CONTROL AREAS, and RELIABILITY COORDINATORS as appropriate.

Requirements

1. **Agreements for emergency assistance.** CONTROL AREAS shall have operating agreements with adjacent CONTROL AREAS that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote CONTROL AREAS.

2. **Staffing and training**. The CONTROL AREA shall be staffed with adequately trained operating personnel. Training for operators shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

3. **Load shedding to prevent separation.** The OPERATING AUTHORITY shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the OPERATING AUTHORITY will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

4. **Emergency plan types.** The OPERATING AUTHORITY shall have emergency plans that address the following:

4.1. **Insufficient Generating Capacity**

4.2. **Transmission**

4.3. **Load Shedding**

4.4. **System Restoration**

5. **Emergency plan elements.** Each CONTROL AREA shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, the CONTROL AREA'S emergency plans shall include:

5.1. **Communications.** Communications protocols to be used during emergencies.

5.2. **Controlling Actions.** List of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the

emergency within NERC established timelines, shall be one of the controlling actions.

5.3. Coordinating Tasks. The tasks to be coordinated with and among adjacent CONTROL AREAS and OPERATING AUTHORITIES within the CONTROL AREA.

5.4. Staffing. Staffing levels for the emergency.

6. Emergency plan review and update. The OPERATING AUTHORITY shall annually review and update each emergency plan. The OPERATING AUTHORITY shall provide a copy of its updated emergency plans to neighboring OPERATING AUTHORITIES and to its RELIABILITY COORDINATOR.

7. Emergency Plan Coordination. The OPERATING AUTHORITY shall coordinate its emergency plans with other OPERATING AUTHORITIES, CONTROL AREAS, and RELIABILITY COORDINATORS as appropriate. This coordination includes the following steps:

7.1. Communications. Establish and maintain reliable communications between interconnected systems.

7.2. Interchange agreements. Arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

7.3. Maintenance coordination. Coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

7.4. Energy deliveries. Arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

Guides

Emergency plans should consider the following items:

1. Fuel supply and inventory. An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching. Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints. Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use. The reduction of the system's own energy use to a minimum.

5. **Public appeals.** Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. **Load management.** Implementation of load management and voltage reductions, if appropriate.

7. **Optimize fuel supply.** The operation of all generating sources to optimize the availability.

8. **Appeals to customers to use alternate fuels.** In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. **Notifying IPPs.** Notification of cogeneration and independent power producers to maximize output and availability.

12. **Requests of government.** Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. **Utilization of Energy Emergency Alert procedures as specified in Appendix 5C.**

16. **Generation redispatch options.**

17. **Transmission reconfiguration options.**

18. **Utilization of Special Protection Schemes.**

19. **Local or INTERCONNECTION-wide transmission loading relief procedures.**

20. **Reserve sharing.**

C. Load Shedding

Introduction

After taking all other remedial steps, an OPERATING AUTHORITY or CONTROL AREA whose integrity is in jeopardy due to insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the INTERCONNECTION.

Requirements

1. Plans for automatic load shedding. Each OPERATING AUTHORITY shall establish plans for automatic load shedding.

1.1. Coordination. Load shedding plans shall be coordinated among the interconnected OPERATING AUTHORITY AREAS.

1.2. Frequency or voltage level. Automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level.

1.2.1. Load shedding steps. Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.

1.2.2. Minimizing risk. The load shed in each step shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

1.2.3. Underfrequency load shedding on separation. After an OPERATING AUTHORITY AREA or CONTROL AREA separates from the INTERCONNECTION, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the OPERATING AUTHORITY or CONTROL AREA shall shed additional load.

1.2.4. Coordination with generator, et al, tripping. Automatic load shedding shall be coordinated throughout the OPERATING AUTHORITY AREAS with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions which will occur under abnormal frequency, voltage, or power flow conditions.

2. Plans for manual load shedding. Each OPERATING AUTHORITY or CONTROL AREA shall have plans for SYSTEM OPERATOR-controlled manual load shedding to respond to real-time emergencies. The manual load shedding shall be capable of being implemented in a timeframe to adequately respond to the emergency.

New. To ensure that the system operator can quickly shed load.

Guides

1. **Load shedding studies.** Automatic load shedding plans should be based on studies of system dynamic performance, simulating the greatest probable imbalance between load and generation.

1.1. **Unacceptable results.** Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result.

1.1.1. **Action on overfrequency.** If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

1.1.2. **Action on overvoltage.** If overvoltages are likely, the load-shedding program should be modified to minimize that probability.

2. **Local area considerations.** When scheduling load to be shed automatically, the system should consider its local area requirements and transmission capabilities between areas.

3. **Automatic isolation plan.** A generation-deficient CONTROL AREA may establish an automatic isolation plan in lieu of automatic load shedding, if by doing so it removes the BURDEN it has imposed on the INTERCONNECTION. This isolation plan may be used only with the consent of neighboring systems, and if it leaves the remaining BULK ELECTRIC SYSTEM intact.

D. System Restoration

[Policy 5E – Emergency Operations–System Restoration]
[Electric System Restoration Reference Document]

Introduction

Each OPERATING AUTHORITY shall have and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. This plan shall be coordinated with other OPERATING AUTHORITIES in the INTERCONNECTION to assure a consistent INTERCONNECTION restoration plan.

A reliable and adequate source of startup power for generating units shall be provided. Where sources are remote from the generating unit, instructions shall be issued to expedite availability. Generation restoration steps shall be verified by actual testing whenever possible.

System restoration procedures shall be verified by actual testing or by simulation.

Requirements

1. **Restoration plan.** Each OPERATING AUTHORITY shall have a restoration plan with necessary operating instructions and procedures to cover emergency conditions, including the loss of vital telecommunications channels.

1.1. **Restoration plan update.** The OPERATING AUTHORITY shall review and update its restoration plan at least annually, and whenever it makes changes in the power system network, and to correct deficiencies found during the simulated restoration exercises.

1.2. **Restoring the INTERCONNECTION.** The OPERATING AUTHORITY'S restoration plans must be developed with the intent of restoring the integrity of the INTERCONNECTION.

1.3. **Coordination.** The OPERATING AUTHORITY shall coordinate its restoration plans with neighboring OPERATING AUTHORITIES.

1.4. **Testing telecommunications.** The OPERATING AUTHORITY will periodically test its telecommunication facilities needed to implement the restoration plan.

2. **SYSTEM OPERATOR training.** The OPERATING AUTHORITY shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

3. **Procedure testing.** The OPERATING AUTHORITY shall verify its restoration procedures by actual testing or by simulation.

4. **Blackstart capability.** The OPERATING AUTHORITY shall ensure the availability and location of Blackstart capability within its OPERATING AUTHORITY AREA to meet the needs of the restoration plan.

New requirement.

Guides

1. **Operation at abnormal voltage and frequency.** Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies.

2. **Generator shutdown and restart.** Emergency sources of power should be available to facilitate safe shutdown, enable turning gear operation, minimize the likelihood of damage to either generating units or their auxiliaries, maintain communications, and expedite restarting.

3. **Emergency power source.** Each generating plant should have a source of emergency power to expedite restarting.

3.1. Hydroelectric plants should have internal provisions for restarting.

3.2. Station service busses. Where station service generators are used in parallel with the system, station auxiliary busses should be separated automatically from the system before the frequency has decayed sufficiently to adversely affect the station service units.

3.3. Station service and area security. The effect of station service generators on area security should be considered before they are shut down for economy.

3.4. Outside startup power source. Where an outside source of power is necessary for generating unit startup, switching procedures should be prearranged and periodically reviewed with SYSTEM OPERATORS and other operating personnel.

4. **Startup and shutdown plans.** Each CONTROL AREA should have written plans for orderly start-up and shutdown of the generating units.

4.1. **Updates.** These plans should be updated when required.

4.2. **Drills.** Drills should be held periodically to assure that plant operators are familiar with the plans.

5. **Blackstart testing.** Periodic tests should be made to verify blackstart capability.

6. **Synchroscope calibration.** All synchroscopes should be calibrated in degrees, and phase angle differences at interconnection points should be communicated in degrees.

D. System Restoration

7. Synchronizing locations and procedures. SYSTEM OPERATORS should know the preplanned synchronizing locations and procedures. Procedures should provide for alternative action to be taken in case of lack of information or loss of communication channels that would affect resynchronizing.

8. Protection systems. Proper protection systems should be considered in the restoration sequence. Relay polarization sources should be maintained during the process.

9. Telecommunications considerations. Backup voice telecommunications facilities, including emergency power supplies and alternate telecommunications channels, should be provided to assure coordinated control of operations during the restoration process.

10. Master trip points. Control centers using SCADA systems should consider providing master trip points for each station to expedite the restoration process.

E. Continuity of Operations

[Backup Control Center Reference Document]

Requirement

CONTROL AREAS and RELIABILITY COORDINATORS shall have a plan to continue reliability operations in the event its control center becomes inoperable.

Guides

1. Must not BURDEN the INTERCONNECTION. The standards of Policy 1, "Generation Control and Performance," should be considered when developing the plan to continue operation so that the CONTROL AREA will not be a BURDEN to the INTERCONNECTION if its own control center becomes inoperable.

1.1. Location of backup center. If the CONTROL AREA has a backup control center, it should be remote from the primary control center site.