Policy 1 — Generation Control and Performance

Version 1a

Re-approved by OC on March 28–29, 2001 for interim implementation through July 11, 2001.

See changes to DCS in Section A.

Policy Subsections

General Criteria

Each system shall either operate a Control Area or make arrangements to be included in a Control Area operated by another system. All load, generation, and transmission operating in an Interconnection must be included within the metered boundaries of a Control Area.

A. Operating Reserve

[Appendix 1A – Area Control Error Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate its MW power resources to provide for a level of OPERATING RESERVE sufficient to account for such factors as errors in forecasting, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, regulating requirements, and Regional and system load diversity. Following loss of resources or load, a CONTROL AREA shall take appropriate steps to reduce its AREA CONTROL ERROR to meet the Disturbance Control Standard (DCS). It shall take prompt steps to protect itself against the next contingency.

Each Region, subregion or RESERVE SHARING GROUP shall specify its operating reserve policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of SPINNING RESERVE and nonspinning reserve, and procedure for applying operating reserve in practice, and the limitations, if any, upon the amount of interruptible load which may be included.

Requirements

1. **Operating reserve distribution.** OPERATING RESERVE shall be dispersed throughout the system and shall consider the effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements.

2. **Contingency review.** All Regions, subregions, RESERVE SHARING GROUPS, and CONTROL AREAS shall frequently review probable contingencies to determine the adequacy of operating reserve.

3. Operating reserve. Each Region, subregion, or RESERVE SHARING GROUP shall specify, and each CONTROL AREA shall provide, as a minimum, operating reserve as follows:

3.1. Regulating reserve. An amount of SPINNING RESERVE, responsive to AGC, which is sufficient to provide normal regulating margin, plus

3.2. Contingency reserve. An additional amount of OPERATING RESERVE sufficient to reduce AREA CONTROL ERROR to meet the Disturbance Control Standard following the most severe single contingency.

3.2.1. Spinning reserve. At least 50% of this operating reserve shall be SPINNING RESERVE, which will automatically respond to frequency deviations.

3.2.1.1. Jointly owned generation with dynamic schedules. CONTROL AREAS that share JOINTLY OWNED UNITS and incorporate DYNAMIC SCHEDULES or PSEUDO-TIES shall include only their share of the unit in their SPINNING RESERVE calculations.

3.2.1.2. Jointly owned generation with fixed schedules. CONTROL AREAS receiving their share of JOINTLY OWNED UNITS as fixed schedules should not include the jointly owned units' share(s) on which the schedules are based in their SPINNING RESERVE calculations. The CONTROL AREA in which the jointly owned unit resides may include the SPINNING RESERVES for its share of the unit.

3.2.2. Reserve sharing group. Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard as if it were a single CONTROL AREA. A RESERVE SHARING GROUP shall be considered in a DISTURBANCE condition any time a group member is in a DISTURBANCE condition and calls for reserves. Compliance may be demonstrated in either of the following two methods:

3.2.2.1. Group compliance to Disturbance Control Standard. The RESERVE SHARING GROUP reviews group ACE (or equivalent) and demonstrates compliance.

3.2.2.2. Group member compliance to Disturbance Control Standard. The RESERVE SHARING GROUP reviews each member's ACE in response to a call for reserves; to be in compliance each member's ACE must return to zero or to its respective pre-disturbance level within ~~ten~~ 15 minutes of the start of the DISTURBANCE.

Changes to Sections 3.2.2.2, 3.2.5, and 3.3 were approved by the Operating Committee on November 15, 2000 for interim implementation through March 29, 2001. See related change in

3.2.3. RESERVE SHARING GROUP monitoring. Each RESERVE SHARING GROUP shall monitor operating reserve availability and actual response.

3.2.4. Reduction in SPINNING RESERVE. The SPINNING RESERVE component may be reduced below 50% of the OPERATING RESERVE providing the Region, subregion, or reserve sharing group can demonstrate that with this reduction and upon its most severe single contingency, it will still be able to meet or exceed established Performance Standards, and not jeopardize the reliable operation of the Interconnection.

3.2.5. **INTERRUPTIBLE LOAD.** INTERRUPTIBLE LOAD may be included in the non-spinning reserve provided that it can be interrupted within ~~ten~~ 15 minutes.

3.2.6. **Disturbance Control Performance Adjustment.** Each control area or reserve sharing group *not meeting the Disturbance Control Standard* during a given quarter, shall increase its Contingency Reserve obligation for the calendar quarter (offset by a month) following the evaluation. The increase shall be directly proportional to the control area's or reserve sharing group's non-compliance to the Disturbance Control Standard. (See the "Performance Standard Training Document," Section C.)

3.3. **Jointly owned generation in another CONTROL AREA.** CONTROL AREAS using fixed schedules for JOINTLY OWNED UNITS that reside outside their CONTROL AREA may include their share of the facility in their OPERATING RESERVE calculations. The OPERATING RESERVE is constrained by their share of the unit(s) capability and their share of the unit(s) ramp capability achievable over a ten-minute period. Included in the ~~ten~~ 15 minutes is the time necessary to schedule the generation into the CONTROL AREA.

3.4. **Reestablishing OPERATING RESERVE.** An additional amount of reserve shall be made available as soon as practicable to aid in reestablishing this minimum OPERATING RESERVE after such reserve has been used.

B. Automatic Generation Control

[Appendix 1A – The Area Control Error (ACE) Equation]
[Performance Standard Training Document]

Criteria

Each CONTROL AREA shall operate sufficient generating capacity under automatic control to meet its obligation to continuously balance its generation and INTERCHANGE schedules to its load. It shall also provide its proper contribution to INTERCONNECTION frequency regulation.

Requirements

1. **CONTROL AREA components.** All load, generation, and transmission operating in an INTERCONNECTION must be included within the metered boundaries of a CONTROL AREA.

2. **AGC calculation.** AUTOMATIC GENERATION CONTROL (AGC) shall compare total net actual interchange to total net scheduled INTERCHANGE plus frequency bias contribution to determine the CONTROL AREA's AREA CONTROL ERROR (ACE).

3. **Regulating capability.** Each CONTROL AREA shall maintain generating regulating capability, synchronized to the INTERCONNECTION that can be increased or decreased by AGC to provide for adequate system regulation and Control Performance.

4. **Manual control.** If AGC has become inoperative, manual control shall be used to adjust generation to maintain scheduled INTERCHANGE.

5. **Regulation service.** It is the responsibility of the CONTROL AREA providing REGULATION SERVICE to notify the entity for whom it is controlling if it is unable to provide the service.

Guides

1. **AGC.** All generating units of consequential size, including JOINTLY OWNED UNITS capable of regulating, should be equipped with AGC to ensure that the CONTROL AREA can continuously balance its generation with its demand plus net scheduled INTERCHANGE.

   1.1. **Data scan rates for ACE.** Data acquisition for and calculation of ACE should occur at least every four seconds.

   1.2. **Data scan rates for joint control and regulation.** For JOINT CONTROL and REGULATION SERVICES, the recommended update rates for data transmission is every four seconds. If a four-second update rate is not possible, the rate should be at least as fast as the slowest scan rate of the participating CONTROL AREAS. In all cases, data shared by the control participants must be identical at all times.

2. **AGC operation.** AGC should remain in operation as much of the time as possible.

3. **AGC suspension.** AGC may be suspended at frequencies above 60.2 Hz or below 59.8 Hz if continued control would result in generation changes that could endanger system reliability.

4. **AGC verification.** Turbine governors and control systems, including AGC, and HVDC control systems should be checked periodically to verify their correct operation.

5. **Load-limiters.** Load-limiting devices should be applied only to restrict the extent of LOAD change, which might have an adverse effect on the generator or jeopardize transmission security.

6. **Regulating margin.** Regulating margin should be distributed over as many units as possible.

7. **Control performance.** Each CONTROL AREA should plan for future adequate control performance to meet expected changes in LOAD characteristics and daily LOAD patterns.

8. **Response rates.** The utility should establish normal and emergency rates of response for each generator and HVDC terminal.

C. Frequency Response and Bias

[Appendix 1A – The Area Control Error (ACE) Equation]
[Frequency Response Characteristic Survey Training Document]

Requirements

1. **Bias setting review.** Each CONTROL AREA shall review its FREQUENCY BIAS SETTINGS by January 1 of each year and recalculate its setting to reflect any change in area frequency response characteristic.

   1.1. **Bias setting method.** The FREQUENCY BIAS SETTING, and the method used to determine the setting, may be changed whenever any of the factors used to determine the current bias value change.

   1.2. **Bias setting reporting.** Each CONTROL AREA shall report its FREQUENCY BIAS SETTING, and method for determining that setting, to the Performance Subcommittee.

   1.3. **Bias setting verification.** Each CONTROL AREA must be able to demonstrate and verify to the Performance Subcommittee that its FREQUENCY BIAS SETTING closely matches or is greater than its system response.

Standards

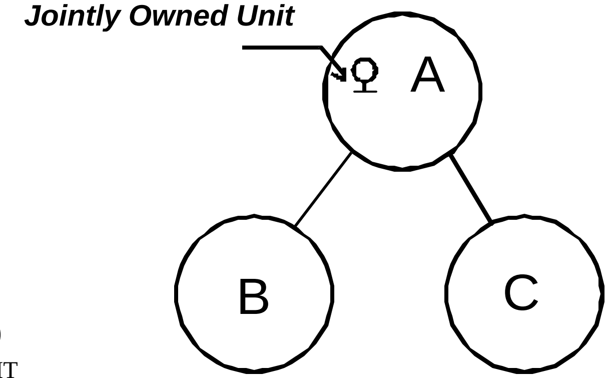
1. **Tie-line bias.** Each CONTROL AREA shall operate its AGC on tie-line frequency bias, unless such operation is adverse to system or INTERCONNECTION reliability. The Standards for tie-line bias control follow:

   1.1. **Bias setting to match frequency response.** The CONTROL AREA shall set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the CONTROL AREA's frequency response characteristic. Frequency bias may be calculated several ways:

      1.1.1. **Fixed bias setting.** A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The fixed value shall be determined by observing and averaging the frequency response characteristic for several DISTURBANCES during on-peak hours.

      1.1.2. **Variable bias setting.** A variable (linear or non-linear) bias value may be used which is based on a variable function of tie-line deviation to frequency deviation. The variable frequency bias value shall be determined by analyzing frequency response as it varies with factors such as LOAD, generation, governor characteristics, and frequency.

      1.1.3. **Bias and jointly owned generation.** CONTROL AREAS that use DYNAMIC SCHEDULING or PSEUDO-TIES for jointly owned units must reflect their respective share of the unit governor droop response into their respective FREQUENCY BIAS SETTING. Fixed schedules for JOINTLY OWNED UNITS mandate that the CONTROL AREA (A) that contains the JOINTLY OWNED UNIT



must incorporate the respective

share of the unit governor droop response for any CONTROL AREAS that have fixed schedules (B and C). The CONTROL AREAS that have a fixed schedule (B and C) but do not contain the JOINTLY OWNED UNIT should *not* include their share of the governor droop response in their FREQUENCY BIAS SETTING.

1.1.4. Minimum bias setting for CONTROL AREAS that serve native LOAD. The CONTROL AREA'S monthly average FREQUENCY BIAS SETTING must be at least 1% of the CONTROL AREA'S estimated yearly peak demand per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.

1.1.5. Minimum bias setting for CONTROL AREAS that do not serve native LOAD. The CONTROL AREA'S monthly average FREQUENCY BIAS SETTING must be at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.

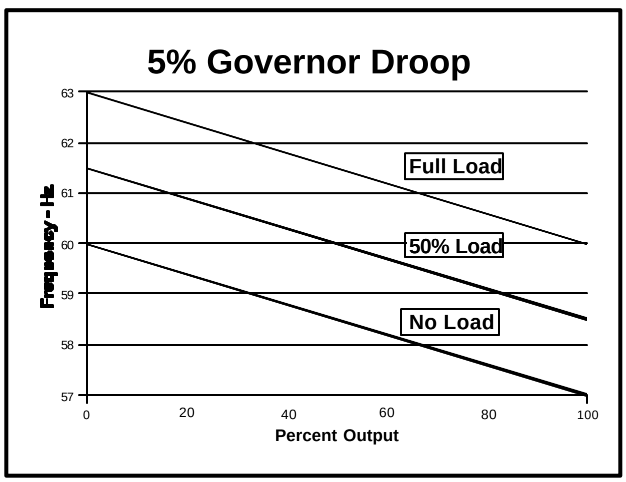
1.1.6. Bias and overlap regulation. A CONTROL AREA that is performing OVERLAP REGULATION SERVICE will increase its FREQUENCY BIAS SETTING to match the frequency response of the entire area being controlled. A CONTROL AREA that is performing SUPPLEMENTAL REGULATION SERVICE shall not change its FREQUENCY BIAS SETTING.

Guides

1. **Governor installation.** Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates

2. **Governors free to respond.** Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.

3. **Governor droop.** All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz (± 36 mHZ).



Graph showing relation between generator output and Interconnection frequency at 0, 50%, and 100% LOAD for a 5% governor droop characteristic.

4. **Governor limits.** Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics.

D. Time Control

[Appendix 1A — The Area Control Error Equation]
[Appendix 1D — Time Error Correction Procedures]

Criteria

INTERCONNECTION frequency shall be scheduled at 60 Hz and controlled to that value except for those periods in which frequency deviations are scheduled to correct time error.

Operating limits for frequency deviation and time error shall be established with Interconnection reliability as first priority.

Each CONTROL AREA shall participate in Interconnection time error correction procedures.

CONTROL AREAS which are operating in parallel shall select one CONTROL AREA to monitor time error for the Interconnection and to issue time error correction orders.

Requirements

1. **Interconnection monitor.** Each INTERCONNECTION shall designate an Interconnection Monitor who shall monitor time error and shall initiate or terminate corrective action orders when time error reaches predetermined limits as shown in Appendix 1D.

2. **Time correction notice and commencement.** Time error corrections shall start and end on the hour or half-hour, and notice shall be given at least 20 minutes before the time error correction is to start or stop.

3. **Time correction serialization.** Time error correction notifications shall be serialized alphabetically on a monthly basis.

4. **Time correction offset.** The time error correction offset shall be applied by either of the following two methods:

   4.1. **Frequency offset.** The frequency schedule may be offset by 0.02 Hz, leaving the FREQUENCY BIAS SETTING normal, or

   4.2. **Schedule offset.** If the CONTROL AREA FREQUENCY BIAS SETTING cannot be offset, the net INTERCHANGE schedule (MW) may be offset by an amount equal to the computed bias contribution during a 0.02 Hz frequency deviation (i.e., 20% of the FREQUENCY BIAS SETTING).

5. **Regional Monitor.** A Regional Monitor shall be designated through which time error correction notifications originating with the Interconnection Monitor will be routed to each system in the Region by way of established Time Notification Channels.

6. **Interconnection time error notification.** The Interconnection Monitor shall periodically issue a notification of time error, accurate to within 0.1 second, to the Regional Monitors to assure uniform calibration of time standards.

7. **Regional time error notification.** Using the Time Notification Channels, the Regional Monitors shall, each hour, on the hour, notify all systems within their respective Regions of the accumulated time error within 0.1 second. Time error notification shall be accompanied by the alphabetic designator if a time error correction is in progress.

8. Calibration of time and frequency devices. Each CONTROL AREA shall at least annually check and calibrate its time error and frequency devices against a common reference.

9. Time correction on reconnection. When one or more CONTROL AREAS has been separated from the INTERCONNECTION, upon reconnection, they shall adjust their time error devices to coincide with the Interconnection by one of the following methods:

9.1. Time correction before reconnection. Before connection, the separated area may institute a Time Error Correction Procedure to correct its accumulated time error to coincide with the indicated time error of the Interconnection Monitor, or

9.2. Device correction after reconnection. After interconnection, the time error devices of the previously separated area may be recalibrated to coincide with the indicated time error of the Interconnection Monitor. A notification of adjusted time error shall be passed through Time Notification Channels as soon as possible after interconnection.

Guides

1. Automatic time correction. The CONTROL AREAS of an INTERCONNECTION may implement automatic time error control as a part of their AGC scheme.

1.1. Participation. If automatic time error correction is used, all CONTROL AREAS of the INTERCONNECTION should participate.

2. Leap seconds. Systems using time error devices that are not capable of automatically adjusting for leap-seconds should arrange to receive advance notice of the leap-second and make the necessary manual adjustment in a manner that will not introduce a disturbance into their control system.

E. Performance Standard

[Appendix 1H – Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards]
[Performance Standard Training Document]

Introduction

The Control Performance Standard (CPS) and Disturbance Control Standard (DCS) define a standard of minimum control performance. Each CONTROL AREA is to have the best operation above this minimum that can be achieved within the bounds of reasonable economic and physical limitations.

Standards

1. Continuous Monitoring. Each control area shall monitor its control performance on a continuous basis against two Standards: CPS1 and CPS2.

1.1. Control Performance Standard (CPS1). Over a year, the average of the clock-minute averages of a control area's ACE divided by -10β ($\beta$is control area frequency bias) times the corresponding clock-minute averages of Interconnection's frequency error shall be less than a specific limit. This limit, ,, is a constant derived from a targeted frequency bound reviewed and set as necessary by the NERC Performance Subcommittee.

1.2. Control Performance Standard (CPS2). The average ACE for each of the six ten-minute periods during the hour (i.e., for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as L_{10}. See the "Performance Standard Training Document," Section B.1.1.2 for the methods for calculating L_{10}.

2. Disturbance conditions. In addition to CPS1 and CPS2, the Disturbance Control Standard shall be used by each control area or reserve sharing group to monitor control performance during recovery from disturbance conditions (see the "Performance Standard Training Document," Section B.2):

2.1. Disturbance Control Standard (DCS). The ACE must return either to zero or to its pre-disturbance level within ~~ten~~15 minutes following the start of the disturbance.

Changes to Section 2.1, was re-approved by the Operating Committee on November 15, 2000 for interim

Requirements

1. ACE values. The ACE used to determine compliance to the Control Performance Standards shall reflect its actual value, and exclude short excursions due to transient telemetering problems or other influences such as control algorithm action.

2. Control Performance Standard (CPS) Compliance. Each CONTROL AREA shall achieve CPS1 compliance of 100% and achieve CPS2 compliance of 90% (see the "Performance Standard Training Document," Section C).

3. PS Surveys. All CONTROL AREAS shall respond to control performance surveys that are requested by the Performance Subcommittee.

4. Disturbance Control Standard Compliance. Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for reportable disturbances (see the "Performance Standard Training Document," Section C).

5. **Disturbance Control Surveys.** Each control area or reserve sharing group shall submit a quarterly summary report to their Regional Performance Subcommittee representative of the respective control area's compliance to the DCS during the reporting quarter.

F. Inadvertent Interchange Standard

[Appendix 1F – Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures]
[Inadvertent Interchange Accounting Training Document]

Introduction

INADVERTENT INTERCHANGE provides a measure of non-scheduled inter-CONTROL AREA energy transfers and bilaterally scheduled inadvertent payback. These transfers are caused by such factors as INTERCONNECTION frequency support, CONTROL AREA regulation, metering errors in frequency and/or interchange parameters (either scheduled or actual), unilateral INADVERTENT INTERCHANGE payback and human errors.

The INADVERTENT INTERCHANGE Standard defines a process for monitoring CONTROL AREAS to help ensure that, over the long term, the CONTROL AREAS do not excessively depend on the INTERCONNECTION for providing or absorbing energy.

Each CONTROL AREA shall, through daily schedule verification and the use of reliable metering equipment, accurately account for INADVERTENT INTERCHANGE. Each CONTROL AREA shall be active in preventing unintentional INADVERTENT INTERCHANGE accumulation. Each CONTROL AREA shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Policies. Each CONTROL AREA interconnection point shall be equipped with a common MWh meter, with readings provided hourly at the control centers of both CONTROL AREAS.

Standards

1. **INADVERTENT INTERCHANGE calculation.** INADVERTENT INTERCHANGE shall be calculated and recorded hourly. **INADVERTENT INTERCHANGE** may accumulate as energy into or out of the CONTROL AREA.

2. **Including all interconnections.** Each CONTROL AREA shall include all AC tie lines of its inter-CONTROL AREA interconnections in its INADVERTENT INTERCHANGE account. Interchange served through jointly owned facilities and interchange with borderline customers must be properly taken into account.

3. **Metering requirements.** All CONTROL AREA INTERCONNECTION points shall be equipped with common MWh meters, with readings provided hourly to the control centers of both CONTROL AREAS.

4. **INADVERTENT INTERCHANGE Accounting.** Adjacent CONTROL AREAS shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each CONTROL AREA shall compute its INADVERTENT INTERCHANGE based on the following:

   4.1. Daily accounting. Each CONTROL AREA, by the end of the next business day, shall agree with its adjacent CONTROL AREAS to the hourly integrated values of:

   4.1.1. NET INTERCHANGE SCHEDULE

   4.1.2. NET ACTUAL INTERCHANGE

4.2. **Monthly accounting**. Each CONTROL AREA shall use the agreed-to Daily accounting data to compile the monthly accumulated INADVERTENT INTERCHANGE for the On-Peak and Off-Peak hours of the month. **[Refer to "Inadvertent Interchange Accounting Training Document"]**

4.3. **After-the-Fact Corrections.** After-the-fact corrections to the agreed-to Daily accounting data shall only be made to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the CONTROL AREA's INADVERTENT INTERCHANGE. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the SENDING CONTROL AREA, RECEIVING CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

5. **INADVERTENT INTERCHANGE payback.** Each CONTROL AREA shall be diligent in reducing accumulated inadvertent balances. INADVERTENT INTERCHANGE accumulations shall be paid back by one or both of the following methods:

5.1. **Energy "in-kind" payback.** INADVERTENT INTERCHANGE accumulated during "on-peak" hours shall only be paid back during "on-peak" hours. INADVERTENT INTERCHANGE accumulated during "off-peak" hours shall only be paid back during "off-peak" hours. [**See Appendix 1F, "On-Peak and Off-Peak Periods."**]

5.1.1. **Bilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back via an INTERCHANGE SCHEDULE with another CONTROL AREA. **[Refer to Policy 3, "Interchange" for Interchange Scheduling Requirements.]**

5.1.1.1. **Opposite balances.** The SOURCE CONTROL AREA and SINK CONTROL AREA must have inadvertent accumulations in the opposite direction.

5.1.1.2. **Agreement on schedule.** The terms of the inadvertent payback INTERCHANGE SCHEDULE shall be agreed upon by all involved Control Areas and TRANSMISSION PROVIDERS in accordance with NERC operating Policy 3, "Interchange".

5.1.1.3. **Participation.** A CONTROL AREA that has been requested to participate in a bilateral payback and that has an inadvertent accumulation in the opposite direction of the requesting CONTROL AREA, must either agree to a bilateral payback INTERCHANGE SCHEDULE, or submit a report to their Performance Subcommittee representative justifying why an INTERCHANGE SCHEDULE was not established. This report shall be submitted within five business days of the request.

5.1.2. **Unilateral payback.** INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a non-zero ACE ensures that the unilateral payback is accounted for in the CPS calculations. The unilateral payback control offset is limited to the CONTROL AREA's L_{10} limit and shall not burden the Interconnection.

5.2. **Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT payback may be utilized.

6. INADVERTENT INTERCHANGE summary. Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in Appendix 1F, "INADVERTENT INTERCHANGE Energy Accounting Practices and Dispute Resolution Process." These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

6.1. Summary balances. INADVERTENT INTERCHANGE summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the "on-peak" and "off-peak" periods.

6.2. Summary submission. Each CONTROL AREA shall submit its monthly summary report to its Performance Subcommittee representative by the 10th business day of the following month. The Performance Subcommittee representative will prepare a composite tabulation and submit that tabulation to the NERC staff by the 20th business day of the month.

6.2.1. No Report. A CONTROL AREA that neither submits a report by the 14th business day of the following month nor provides, by the 14th business day of the following month, a reason for not submitting the required data, shall accept the values provided by its adjacent CONTROL AREAS.

6.2.2. Dispute Resolution. Adjacent CONTROL AREAS that cannot mutually agree upon their respective NET ACTUAL INTERCHANGE or NET SCHEDULED INTERCHANGE quantities by the 10th business day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Performance Subcommittee representative. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. The Dispute Resolution Process is described in Appendix 1F.

G. Control Surveys

[Area Interchange Error Survey Training Document]
[Frequency Response Characteristic Survey Training Document]
[Performance Standard Training Document]

Criteria

Periodic surveys of the control performance of the CONTROL AREAS shall be conducted. These surveys serve the purpose of revealing control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

Requirements

1. **Surveys.** The CONTROL AREAS in each INTERCONNECTION shall perform each of the following surveys, as described in the Performance Standard Training Document, when called for by the Performance Subcommittee:

   1.1. **AIE survey.** Area Interchange Error survey to determine the CONTROL AREAS' INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.

   1.2. **FRC survey.** Area Frequency Response Characteristic survey to determine the CONTROL AREAS' response to changes in system frequency.

   1.3. **CPS and DCS surveys.** Performance Standard surveys to monitor the CONTROL AREAS' control performance during normal and DISTURBANCE situations.

H. Control and Monitoring Equipment

[Appendix 1H – Minimum Data Collection Requirements for Use in Monitoring NERC Performance Standards]

Criteria

The control equipment of each CONTROL AREA shall be designed and operated so that the CONTROL AREA can continuously and accurately meet its system and INTERCONNECTION control obligations and measure its performance. The control equipment design and operation shall follow accepted industry techniques.

All CONTROL AREA interconnection points shall be equipped to telemeter MW power flow to both area control centers simultaneously. The telemetering shall be from an agreed-upon terminal utilizing common metering equipment.

The system operator's displays and consoles shall present a clear and understandable picture of CONTROL AREA parameters. This includes necessary information from facilities within other CONTROL AREAs in addition to internal information.

Requirements

1. **Hourly verification of tie flows.** Each CONTROL AREA shall perform hourly control error checks using tie-line MWh meters to determine the accuracy of its control equipment.
2. **Adjustments for equipment error.** The SYSTEM OPERATOR shall adjust control settings to compensate for any equipment error until repairs can be made.
3. **Minimum data recording.** SYSTEM OPERATORS shall be provided with a recording of those variables necessary to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, area control error (ACE), system frequency, and net tie-line INTERCHANGE data shall be continuously recorded.
4. **Data filtering.** The power flow and ACE signals that are transmitted for REGULATION SERVICE shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines.
5. **Metering for jointly owned generation.** Common metering equipment shall be installed where DYNAMIC SCHEDULES or PSEUDO-TIES are implemented between two or more CONTROL AREAS to deliver the output of JOINTLY OWNED UNITS or to serve remote LOAD.
6. **Tie flows in ACE calculation.** All tie-line flows between CONTROL AREAs shall be included in each CONTROL AREA's ACE calculation.

Guides

1. **Backup power for data recording.** Adequate and reliable backup power supplies should be provided and periodically tested at the system control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.
2. **Tie-line metering.** All tie-line MW and MWH/Hr telemetry should be telemetered to both control centers, and should emanate from a common, agreed-upon terminal using common primary metering equipment.