POLICY 1

LOAD-FREQUENCY CONTROL AND PERFORMANCE

P1 – Policy 1: Load-Frequency Control and Performance[E]

Chapters

A. Primary Control

B. Secondary Control

C. Tertiary Control

D. Time Control

E. Measures for Emergency Conditions

Introduction

The GENERATION of power units connected to the UCTE network needs to be controlled and monitored for secure and high-quality operation of the SYNCHRONOUS AREAS. The generation control, the technical reserves and the corresponding performance measurements are essential to allow TSOs to perform daily operational business. Control actions are performed in different successive steps, each with different characteristics and qualities, and all depending on each other:

- PRIMARY CONTROL (see section ⏩P1-A) starts within seconds as a joint action of all undertakings involved.
- SECONDARY CONTROL (see section ⏩P1-B) replaces PRIMARY CONTROL after minutes and is put into action by the responsible undertakings / TSOs only.
- TERTIARY CONTROL (see subsection ⏩P1-C) frees SECONDARY CONTROL by re-scheduling generation and is put into action by the responsible undertakings / TSOs.
- TIME CONTROL (see subsection ⏩P1-D) corrects global TIME DEVIATIONS of the SYNCHRONOUS TIME in the long term as a joint action of all undertakings / TSOs.

Please refer to the glossary of terms of the UCTE Operation Handbook (see ⏩G) for detailed definitions of terms used within this policy and to Appendix 1 (see ⏩A1) for basics and principles of load-frequency control and performance.

History of changes

v2.2	**draft**	**20.07.2004**		**Final wording**
v2.1	**draft**	**17.06.2004**	**OH-Team**	**Changes after consultation**

Current status

This document summarises current UCTE rules and recommendations relating to load-frequency control and performance issues in a new structure, with additional items describing today's common practice.

This policy replaces previous UCTE ground rules and recommendations regarding PRIMARY and SECONDARY frequency and active POWER CONTROL, regulation reserves and correction of SYNCHRONOUS TIME. This version of the document (version 2.2, level E, dated 20.07.2004) has "final policy" status.

A. Primary Control

[UCTE Operation Handbook Appendix 1 Chapter A: Primary Control, 2004]

Introduction

The objective of PRIMARY CONTROL is to maintain a balance between GENERATION and consumption (DEMAND) within the SYNCHRONOUS AREA, using turbine speed or turbine governors. By the joint action of all interconnected undertakings / TSOs, PRIMARY CONTROL aims at the operational reliability of the power system of the SYNCHRONOUS AREA and stabilises the SYSTEM FREQUENCY at a stationary value after a disturbance or incident in the time-frame of seconds, but without restoring the reference values of SYSTEM FREQUENCY and power exchanges (see ⏩P1-B for SECONDARY CONTROL). Adequate PRIMARY CONTROL depends on generation resources made available by generation companies to the TSOs. Please refer to appendix 1 (see ⏩A1-A) for basics and principles of PRIMARY CONTROL.

This policy section replaces the corresponding sections for primary control in the latest "UCPTE-Ground Rules concerning primary and secondary control of frequency and active power within the UCPTE", dated 1998.

Criteria

C1. **Nominal frequency**. The set-point frequency (or scheduled frequency) f_0 (see ⏩P1-D) defines the target value of the SYSTEM FREQUENCY f for system operation. Outside periods for the correction of SYNCHRONOUS TIME (see ⏩P1-D), the nominal frequency value in the SYNCHRONOUS AREA is 50 Hz.

C2. **Frequency deviations**. A FREQUENCY DEVIATION Δf (the departure $f–f_0$ of the actual SYSTEM FREQUENCY f from the scheduled frequency f_0) results from a disturbance or an incident and may occur during normal system operation. Different criteria are used to distinguish the size of this deviation:

C2.1. **Calling up of Primary Control**. To avoid calling up of PRIMARY CONTROL in undisturbed operation at or near nominal frequency, the FREQUENCY DEVIATION should not exceed ±20 mHz. PRIMARY CONTROL is activated if the FREQUENCY DEVIATION exceeds ±20 mHz (the sum of the accuracy of the local frequency measurement and the insensitivity of the controller, see ⏩P1-A-R1 and ⏩P1-A-R2).

C2.2. **Maximum Quasi-Steady-State Frequency Deviation.** The quasi-steady-state FREQUENCY DEVIATION in the SYNCHRONOUS AREA must not exceed ±180 mHz (maximum permissible steady-state FREQUENCY DEVIATION; under the condition of SELF-REGULATION OF THE LOAD according to ⏩P1-A-C4).

C2.3. **Minimum Instantaneous Frequency.** The instantaneous frequency must not fall below 49.2 Hz (that corresponds to -800 mHz as maximum permissible dynamic FREQUENCY DEVIATION from the nominal frequency ⏩P1-A-C1) in response to a shortfall in generation capacity equal to or less than the reference incident according to ⏩P1-A-C3.

C2.4. **Load-Shedding Frequency Criterion**. LOAD-SHEDDING (automatic or manual, including the possibility to shed pumping units) starts from a SYSTEM FREQUENCY of 49.0 Hz (or below). The detailed step-plans for LOAD-SHEDDING (in the responsibility of the TSOs, with the possibility to perform earlier shedding of pumping units at higher frequency value as an operational measure, with the lowest value of 47.5 Hz and the need of progressive stages in between) define additional frequency criteria for further measures.

C2.5. **Maximum Instantaneous Frequency**. The instantaneous frequency must not exceed 50.8 Hz (that corresponds to +800 mHz as maximum permissible dynamic FREQUENCY DEVIATION from the nominal frequency ⏩P1-A-C1) in response to a loss of load or interruption of power exchanges equal to or less than the reference incident according to ⏩P1-A-C3.

C3. Reference Incident. The maximum instantaneous deviation between generation and demand in the SYNCHRONOUS AREA (by the sudden loss of generation capacity, load-shedding / loss of load or interruption of power exchanges) to be handled by PRIMARY CONTROL starting from undisturbed operation depends on the size of the area / zone[1] and on the size of the largest generation unit or generation capacity connected to a single bus bar located in that area[2].

C3.1. First Synchronous Zone. For the first synchronous zone as in 2003 the maximum power deviation to be handled is 3000 MW, assuming realistic characteristics concerning system reliability and size of loads and generation units.

C3.2. Second Synchronous Zone. For the second synchronous zone as in 2003, the maximum power deviation to be handled is 540 MW.

C3.3. Other Synchronous Areas. For other SYNCHRONOUS AREAS (UCTE SYNCHRONOUS AREAS), that are not connected to the main synchronous zone, the size of the reference incident needs to be defined in each particular case with respect to the size of the area and the size of the largest generation units located in that area.

C3.4. Observation Incident. Incidents, such as the sudden loss of generation or load, that exceed 1000 MW in the first synchronous zone or 250 MW in the second synchronous zone are considered to be relevant for system observation in that zone[3].

C4. Frequency Characteristics. Key values of the frequency characteristics are defined on the basis of system observation[4].

C4.1. Self-Regulation of Load. The self-regulation of the load in all SYNCHRONOUS AREAS is assumed to be 1 %/Hz, that means a load decrease of 1 % occurs in case of a frequency drop of 1 Hz.

C4.2. Security Margin. For FREQUENCY CONTROL, a static security margin of 20 mHz is defined, identical with the calling up of PRIMARY CONTROL (see ⏩P1-A-C2.1).

C5. Deployment Times of Primary Control Reserve. The time for starting the action of PRIMARY CONTROL is a few seconds starting from the incident, the deployment time for 50 % or less of the total PRIMARY CONTROL RESERVE is at most 15 seconds and from 50 % to 100 % the maximum deployment time rises linearly to 30 seconds.

C6. Frequency Change Indicators. For special use in a post-operation analysis, the following criteria are defined to measure the characteristics of absolute changes of the SYSTEM FREQUENCY within a short period of time.

1: The definitions of synchronous zones (first and second zone as existing today as a result of the Balkan war) are temporal only due to the planned reconnection of the UCTE area. The reconnection is scheduled for 2005. The system load for the first SYNCHRONOUS AREA typically varies between 150 GW off-peak and 300 GW peak.

2: The final values used in the definition of the reference incidents are determined by the UCTE SG "TSO-Forum" and finally confirmed by the UCTE WG "Operations and Security" and the UCTE SC. The values given are under consideration.

3: The values have been adapted by the UCTE SG "TSO-Forum" in 2001 and are reviewed annually.

4: The final values used in the definition are determined by the UCTE SG "TSO-Forum" and finally confirmed by the UCTE WG "Operations and Security" and the UCTE SC. The values given are under consideration.

C6.1. **Periods of Time**. Typical periods of time are ±60 minutes, ±15 minutes and ±5 minutes around the time of an incident or the change of the hour.

C6.2. **Maximum Time Grid**. The values used for frequency change indicators are based on a maximum time grid of 10 seconds.

C6.3. **Frequency Patterns**. Typical patterns of the frequency within a short period of time can be: constant with / without offset, decrease, increase, peak up, peak down, peak up down and peak down up.

C6.4. **Peak Frequency Range within Period**. The peak frequency range is calculated as the difference between the maximum and the minimum frequency within the given period of time.

C6.5. **Peak Frequency Derivative within Period**. The peak frequency derivative is determined as the maximum or minimum derivative of the frequency within the given period of time.

Requirements

R1. **Accuracy of Frequency Measurements**. For PRIMARY CONTROL, the accuracy of local frequency measurements used in the PRIMARY CONTROLLERS must be better than or equal to 10 mHz.

R2. **Insensitivity of Controllers**. The insensitivity range of PRIMARY CONTROLLERS should not exceed ±10 mHz. Where dead bands exist in specific controllers, these must be offset within the CONTROL AREA / BLOCK concerned.

R3. **Primary Control Reserve**. PRIMARY CONTROL RESERVE needs to have certain characteristics to be usable for PRIMARY CONTROL.

R3.1. **Reserve Distribution**. In general, the PRIMARY CONTROL RESERVE must be physically distributed as evenly as possible between the different regions (usually between the CONTROL AREAS / BLOCKS) in the SYNCHRONOUS AREA (see also ⏩P1-B and the distribution procedure).

R3.2. **Total Size of Reserve**. The total PRIMARY CONTROL RESERVE (in MW) required for operation of a SYNCHRONOUS AREA is of the same size as the reference incident for that area (see ⏩P1-A-C3).

R3.3. **Availability of Reserves**. In total and as a minimum, the full PRIMARY CONTROL RESERVE for each area must be available continuously without interruption, not depending on the unit commitment in detail.

R3.4. **Operational Usability of Reserves**. The entire PRIMARY CONTROL RESERVE (and each share of it) must be fully activated in response to a quasi-steady-state FREQUENCY DEVIATION of ±200 mHz or more.

R4. **Network Power Frequency Characteristic**. The NETWORK POWER FREQUENCY CHARACTERISTIC describes the real dependency between SYSTEM FREQUENCY and POWER IMBALANCE with a linear approximation.

R4.1. **Constant Network Power Frequency Characteristic**. In order to ensure that the principle of joint action is observed, the NETWORK POWER FREQUENCY CHARACTERISTICS of the various CONTROL AREAS is taken to remain as constant as possible. This applies particularly to small FREQUENCY DEVIATIONS, where the "dead bands" of generators may have an unacceptable influence upon the supply of PRIMARY CONTROL energy in the CONTROL AREAS concerned.

R4.2. **Share of Primary Control**. The NETWORK POWER FREQUENCY CHARACTERISTIC of PRIMARY CONTROL only for the first synchronous zone is calculated out of ⏩P1-A-R3.2 and ⏩P1-A-C2.2 (including the security margin ⏩P1-A-C4.2) to 15000 MW/Hz.

R4.3. Share of Self-Regulation. . The NETWORK POWER FREQUENCY CHARACTERISTIC of SELF-REGULATION only for the first synchronous zone is calculated out of ⏩P1-A-C4.1 and ⏩P1-A-C3 to 3000 MW/Hz.

R4.4. Overall Network Power Frequency Characteristic. The overall NETWORK POWER FREQUENCY CHARACTERISTIC for the first synchronous zone is set to 18000 MW/Hz and for the second synchronous zone set to 3000 MW/Hz.

Standards

S1. System Reliability. In case of a first contingency or incident according to ⏩P1-A-C3, such as the loss of generation or load or interruption of power exchanges in an undisturbed situation, PRIMARY CONTROL must maintain reliable system operation.

S2. Primary Control Action. The action of the individual generators performing PRIMARY CONTROL must have the following characteristics, to be ensured by all TSOs:

S2.1. Adjustment of Generation. Power generation under PRIMARY CONTROL must be constantly adjusted to follow changes of SYSTEM FREQUENCY.

S2.2. Deployment. Total PRIMARY CONTROL within the entire SYNCHRONOUS AREA (as well as within each CONTROL AREA / BLOCK) must follow the deployment times of PRIMARY CONTROL RESERVE (see ⏩P1-A-C5). Each TSO must check the deployment times within his CONTROL AREA / BLOCK on a regular basis.

S2.3. Duration of Delivery. PRIMARY CONTROL POWER must be delivered until the power deviation is completely offset by the SECONDARY CONTROL RESERVE of the CONTROL AREA / BLOCK in which the power deviation has occurred (the minimum duration for the capability of delivery for primary control is 15 minutes, see ⏩P1-B).

S3. Primary Control Target. Starting from undisturbed operation (see ⏩P1-A-C2), a reference incident (see ⏩P1-A-C3) must be offset by PRIMARY CONTROL alone, without the need for LOAD-SHEDDING in response to a FREQUENCY DEVIATION. In addition, where the self-regulating effect of the load is assumed according to ⏩P1-A-C4, the FREQUENCY DEVIATION must not exceed the quasi-steady-state frequency deviation (see ⏩P1-A-C2).

S4. Principle of Joint Action. PRIMARY CONTROL is based on the principle of joint action to ensure system reliability and interconnected operation. This includes an overall distribution of reserves and control actions, as determined and decided by the UCTE SG “TSO-Forum” on an annual basis for the next calendar year.

S4.1. Contributions to Primary Reserves. Each CONTROL AREA / BLOCK must contribute to the PRIMARY CONTROL RESERVE as required. The respective shares are defined by multiplying the calculated reserve for the entire SYNCHRONOUS AREA (see ⏩P1-A-R3 and ⏩P1-B) and the contribution coefficients c_i of the various CONTROL AREAS / BLOCKS. The sum of all shares must amount to the total PRIMARY CONTROL RESERVE.

S4.2. Contribution to Control. Each CONTROL AREA / BLOCK must contribute to the correction of a disturbance in accordance with its respective contribution coefficient c_i for PRIMARY CONTROL.

S4.3. Contribution Coefficients. The contribution coefficients must be determined and published annually for each CONTROL AREA / BLOCK. The contribution coefficients are binding for the corresponding interconnection partner / TSO for one calendar year. They are based on the share of the energy generated within one year in relation to the entire SYNCHRONOUS AREA. The sum of all contributions coefficients must amount to 1.

Procedures

P1. Contribution Coefficients. The UCTE SG "TSO-Forum" determines and decides about the contribution coefficients of each CONTROL AREA / BLOCK for each SYNCHRONOUS ZONE on an annual basis (published before the 1st of December) and sets these values into operation on the 1st of January of the next year.

P2. Observation of Outages. Outages in production or consumption exceeding the size of the observation incident (see ⏩P1-A-C3) are recorded for analysis. The corresponding information about location, time, size and type of the disturbance / incident is recorded and made available to the members of the association.

P3. Frequency Analysis. The detailed analysis of the characteristics of the SYSTEM FREQUENCY is made according to that of the following procedures.

- **P3.1. Frequency Change Analysis**. The frequency change analysis[5], see appendix, uses the frequency change indicators (see ⏩P1-A-C6) for evaluation and comparison.

P4. Control Performance Measurement. The NETWORK POWER FREQUENCY CHARACTERISTIC is calculated in response to a disturbance (such as an observation incident), based on measurements of the SYSTEM FREQUENCY and other key values and on a statistical analysis.

- **P4.1. Control Performance Report**. UCTE publishes results of a control performance analysis on a regular basis in the "Regular Report of the Performance of the Primary and Secondary Load –Frequency Control", prepared by the UCTE SG "TSO-Forum".

Guidelines

G1. Measurement Cycle for Primary Control. Typically the cycle for measurements for PRIMARY CONTROL action must be in the range of 0.1 seconds to 1 second.

G2. Measurement Cycle for Observation. The cycle for measurements of the SYSTEM FREQUENCY for central system observation must be in the range of 1 second (strongly recommended) to at most 10 seconds.

5: Also known as frequency measurement campaign.

B. Secondary Control

[UCTE Operation Handbook Appendix 1 Chapter A: Secondary Control, 2004]

[UCPTE Rule 44: Control of active power in the grid of the UCPTE, 1990]

[UCPTE-Ground Rules concerning primary and secondary control of frequency and active power within the UCPTE, 1998]

Introduction

SECONDARY CONTROL maintains a balance between GENERATION and consumption (DEMAND) within each CONTROL AREA / BLOCK as well as the SYSTEM FREQUENCY within the SYNCHRONOUS AREA, taking into account the CONTROL PROGRAM, without impairing the PRIMARY CONTROL that is operated in the SYNCHRONOUS AREA in parallel but by a margin of seconds (see ⏩P1-A).

SECONDARY CONTROL makes use of a centralised AUTOMATIC GENERATION CONTROL, modifying the active power set points / adjustments of GENERATION SETS in the time-frame of seconds to typically 15 minutes. SECONDARY CONTROL is based on SECONDARY CONTROL RESERVES that is under automatic control. Adequate SECONDARY CONTROL depends on generation resources made available by generation companies to the TSOs. Please refer to Appendix 1 (see ⏩A1-B) for basics and principles of SECONDARY CONTROL.

This policy section replaces the corresponding sections for secondary control in the latest "UCPTE-Ground Rules concerning primary and secondary control of frequency and active power within the UCPTE", dated 1998.

Criteria

C1. **K-Factor**. The K-FACTOR defines the dependency between SYSTEM FREQUENCY and deviation of power exchanges for SECONDARY CONTROL.

C1.1. **Frequency Control Gain**. The common gain defined for FREQUENCY CONTROL within SECONDARY CONTROL is set to 1.1 (110 %), used to overcome the uncertainty of the SELF-REGULATING effect.

C1.2. **K-Factor Calculation**. The K-FACTOR K_{ri} of a CONTROL AREA / BLOCK for SECONDARY CONTROL is calculated by the product of the frequency control gain 1.1 (see ⏩P1-B-C1.1), the contribution coefficient c_i of that area (see ⏩P1-A-S4.3) and the total NETWORK POWER FREQUENCY CHARACTERISTIC (see ⏩P1-A-R4.4).

C1.3. **Total K-Factor for Secondary Control**. The total K-FACTOR for SECONDARY CONTROL in the FIRST SYNCHRONOUS ZONE amounts to 19801 MW/Hz for the year 2004. The total K-FACTOR for SECONDARY CONTROL in the SECOND SYNCHRONOUS ZONE comes to 3301 MW/Hz for the year 2004[6].

C2. **Area Control Error**. Within each CONTROL AREA / BLOCK, the individual AREA CONTROL ERROR *G* (ACE) needs to be controlled to zero on a continuous basis. The ACE is calculated as the sum of the power control error and the frequency control error ($G=\Delta P+ K^*\Delta f$).

C2.1. **Power Control Error**. The power control error ΔP of a CONTROL AREA / BLOCK is the total POWER DEVIATION of that area in interconnected operation, calculated as the difference between the total active power flow (sum of all related measurements) and the CONTROL PROGRAM (sum of all related exchange schedules and the compensation programs).

C2.2. **Frequency Control Error**. The frequency control error $K^*\Delta f$ of a CONTROL AREA / BLOCK is the product of the FREQUENCY DEVIATION Δf (see ⏩P1-A-C2) and the K-FACTOR of the CONTROL AREA / BLOCK K_{ri} (see ⏩P1-B-C1.2).

6: *The final values are determined by the UCTE SG "TSO-Forum" on a regular basis.*

C3. **Secondary Control Deviation**. A disturbance or an incident (inside or outside of the CONTROL AREA / BLOCK) will result in an AREA CONTROL ERROR. Different criteria are used to distinguish the size of this deviation (see ⏩A1 for further details, look for "Calling up of SECONDARY CONTROL").

C4. **Island Operation**. In contrast to interconnected operation, island operation is the unusual operation mode, where all interconnections / TIE-LINES of a CONTROL AREA / BLOCK are disconnected (e.g. after a disturbance the CONTROL AREA is not connected to the SYNCHRONOUS AREA any more) and thus no EXCHANGE PROGRAMS are possible.

C5. **ACE Change Indicators**. For special use in a post-operation analysis, special criteria are defined to measure the characteristics of absolute changes of the ACE of a CONTROL AREA / BLOCK within a short period of time (see also ⏩P1-A-C6).

Requirements

R1. **Control Area / Block**. The following preconditions are defined for CONTROL AREAS / BLOCKS in the UCTE:

R1.1. **Control program**. A CONTROL AREA / BLOCK is capable to maintain the control program towards all other CONTROL AREAS / BLOCKS of the SYNCHRONOUS AREA at the scheduled value.

R1.2. **Control Hierarchy and Organisation**. Each CONTROL AREA / BLOCK may divide up into sub-control areas that operate their own underlying generation control. A CONTROL BLOCK organises the internal SECONDARY CONTROL according to one of the following schemes (basically, the type of internal organisation must not influence the behaviour or quality of SECONDARY CONTROL between the CONTROL BLOCKS):

- **Centralised**: SECONDARY CONTROL for the CONTROL BLOCK is performed centrally by a single controller (as one CONTROL AREA); the operator of the block has the same responsibilities as the operator of a CONTROL AREA.
- **Pluralistic**: SECONDARY CONTROL is performed in a decentralised way with more than one CONTROL AREA; a single TSO, the BLOCK CO-ORDINATOR, regulates the whole block towards its neighbours with its own controller and regulating capacity, while all the other TSOs of the block regulate their own CONTROL AREAS in a decentralised way on their own.
- **Hierarchical**: SECONDARY CONTROL is performed in a decentralised way with more than one CONTROL AREA; a single TSO, the BLOCK CO-ORDINATOR, operates the superposed block controller which directly influences the subordinate controllers of all CONTROL AREAS of the CONTROL BLOCK; the BLOCK CO-ORDINATOR may or may not have regulating capacity on its own.

R1.3. **Area Demarcation**. Each CONTROL AREA / BLOCK is physically demarcated by the position of the points for measurement of the interchanged power to the remaining interconnected network.

R2. **Responsible Operator**. Each CONTROL AREA / BLOCK must be operated by an individual TSO that has the responsibility for the transmission system operation of this area (usually coincident with the territory of a company or a country), including the responsibility for availability, operation and provision of PRIMARY CONTROL and SECONDARY CONTROL within the CONTROL AREA / BLOCK to maintain the POWER INTERCHANGE of his CONTROL AREA / BLOCK at the scheduled value and, consequently, to support the restoration of FREQUENCY DEVIATIONS in the interconnected network. The operator is also responsible for accounting within its territory (see ⏩P2).

R3. **Secondary Controller.** In order to control the ACE (see ⏩P1-B-C2) to zero, SECONDARY CONTROL must be performed in the corresponding control centre by a single automatic SECONDARY CONTROLLER, that needs to be operated in an on-line and closed-loop manner.

R3.1. Controller Type and Characteristic. In order to have no residual error, the SECONDARY CONTROLLER must be of PI (proportional-integral) type. The integral term must be limited in order to have a non-windup control action, able to react immediately in case of large changes or a change of the sign of the ACE. Measurement cycle times, integration times and controller cycle time must be co-ordinated.

R3.2. Availability and Reliability. The automatic SECONDARY CONTROLLER, operated on-line and closed-loop, must have a high availability and must operate highly reliable.

R3.3. Controller Cycle Time. The cycle time for the automatic SECONDARY CONTROLLER should be between 1 second and 5 seconds, to minimise the total time delay between occurrence, reaction and response in the scope of the overall control performance of the control area[7].

R3.4. Programmed Values. Programmed values for SECONDARY CONTROL (e.g. for power exchanges and frequency set-points) must be entered into the controller as time-dependant set-point values based on schedules. See ⏩P2 for details on scheduling.

R3.5. Frequency Control. The gain for FREQUENCY CONTROL within SECONDARY CONTROL must be set to the K-FACTOR (see ⏩P1-B-C1.2)**.** In case of ISLAND operation (see ⏩P1-B-C4) the SECONDARY CONTROLLER of a CONTROL AREA / BLOCK must perform automatic frequency control for the CONTROL AREA / BLOCK.

R3.6. Power Exchange Set-Point Value. The algebraic sum of the programmed power exchanges between a CONTROL AREA / BLOCK and ADJACENT CONTROL AREAS / BLOCKS constitutes the POWER EXCHANGE set point of the CONTROL AREA'S / BLOCK'S SECONDARY CONTROLLER.

R3.7. Ramping of Schedules. In order to prevent excessive FREQUENCY DEVIATIONS when changes of CONTROL PROGRAMS occur, it is necessary that each change be converted to a ramp with a ramp period of 10 minutes, starting 5 minutes before the agreed time of change (the change of the hour or of the quarter, see ⏩P2 for definition of exchange schedules) and ending 5 minutes later. It is required that the ramping be performed in the same way by all controllers of the SYNCHRONOUS AREA.

R3.8. Manual Control Capability. In case of deficiency of the automatic SECONDARY CONTROL, manual control action must be possible.

R4. Secondary Control Reserve. An adequate SECONDARY CONTROL RESERVE must be available at all times to cover expected DEMAND fluctuations and the loss of a generating unit. If the loss of the largest generating unit is not already covered by the requisite SECONDARY CONTROL RESERVE, additional TERTIARY CONTROL RESERVE {15 MINUTE RESERVE} is required to offset the shortfall within a short time, see ⏩P1-C.

R4.1. Availability of Resources. Adequate SECONDARY CONTROL depends on generation resources made available by generation companies to the TSO.

R4.2. Sufficient Controllable Generation. In each CONTROL AREA / BLOCK, sufficient controllable generation or load control (under automatic control) must be available in order to be able to control the AREA CONTROL ERROR to zero.

R4.3. Backup by Tertiary Control Reserve. SECONDARY CONTROL keeps the CONTROL AREA'S / BLOCK'S balance, in normal operating conditions, and contributes to restore it, in case of a sudden unbalance due to an incident (see also ⏩P1-A-C3). In case of a sudden large unbalance or a sustained DEMAND

7: In order to reflect current practice of SECONDARY CONTROL and operational experiences, the "target value of 1 s to 2 s for the future" of the former UCTE rule and recommendation has been replaced accordingly.

variation, TERTIARY CONTROL RESERVE is required to restore the SECONDARY CONTROL RESERVES (see ⏩P1-C).

R5. **Tie-Lines**. Certain criteria / characteristics need to be matched by different types of TIE-LINES that may be in use for SECONDARY CONTROL.

R5.1. **Transmission Lines, Transformers**. The list of TIE-LINES of the CONTROL AREA / BLOCK in operation is maintained and updated on a regular basis.

R5.2. **Radial Operation of Generating Units**. In case of the radial operation of generating units these are considered as internal generating units within the CONTROL AREA / BLOCK (e.g. using VIRTUAL TIE-LINES).

R5.3. **Jointly Owned Generating Units**. Jointly owned generating (with GENERATION shares belonging to different CONTROL AREAS) shall be equipped with metering and measurement equipment providing function of VIRTUAL TIE-LINE between two or more CONTROL AREAS, unless the share of the production is delivered via SCHEDULE.

R5.4. **Metering and Measurement**. All TIE-LINES from a CONTROL AREA to adjacent CONTROL AREAS (across the border) must have measurements and meters in operation to record the actual active (and reactive) power flow in MW (MVAr) in real-time and the energy in MWh in the time-frame for power exchanges that is used (one hour at the maximum, see ⏩P2).

R5.5. **Transmission of Measurements**. The measurements must be transmitted in a reliable manner to the SECONDARY CONTROLLER.

R5.6. **Accuracy of Measurements**. The accuracy of the active power measurements on each TIE-LINE must be better than 1.5 % of its rated value (the complete measurement range, including discretisation). The measurement cycle time should not exceed 5 seconds and the measurement times of measurement values should not differ more than 5 seconds. Measurement cycle times, controller cycle times and controller integration times shall be coordinated.

R6. **System Frequency**. The following requirements are defined for the use of the SYSTEM FREQUENCY for SECONDARY CONTROL:

R6.1. **Accuracy of Measurement**. For SECONDARY CONTROL, the accuracy of frequency measurement must be between 1.0 mHz and 1.5 mHz (*target value for the future*).

R6.2. **Frequency Set-Point**. The actual frequency set-point value (nominal value of 50 Hz, see ⏩P1-A-C1) for TIME CONTROL (see ⏩P1-D-S4) must be used within the SECONDARY CONTROLLER for calculation of the FREQUENCY DEVIATION, to be able to limit the deviation between SYNCHRONOUS TIME and UTC.

R7. **Data Recordings.** Each TSO must be equipped with a recording of all values needed for monitoring of the response of (PRIMARY and) SECONDARY CONTROLLERS and for analysis of normal operation and incidents in the INTERCONNECTED SYSTEM.

Standards

S1. **Operation of Secondary Control**: Each TSO operates sufficient generating capacity under automatic control by the SECONDARY CONTROLLER to meet its obligation to continuously balance its generation and interchange schedules to its load for the CONTROL AREA / BLOCK.

S2. **Usage of Secondary Control**. SECONDARY CONTROL must only be used in order to correct an AREA CONTROL ERROR. SECONDARY CONTROL must not be used for other purposes, e.g. to minimise unintentional power exchanges or to correct other imbalances. SECONDARY CONTROL shall not counteract PRIMARY CONTROL under emergency conditions, with possible impact on the usage of SECONDARY CONTROL in such situations in a co-ordinated way.

S3. **Control Target.** One quality criterion for SECONDARY CONTROL is the time taken for a CONTROL DEVIATION to return to zero, i.e. the time taken to restore the SYSTEM FREQUENCY to its set point value and to restore power interchanges to their set point (programmed) values. In practice, PRIMARY CONTROL action begins within a few seconds of a FREQUENCY DEVIATION, and takes full effect not more than 30 seconds later. Frequency and power interchanges must begin to return to their set point values as a result of SECONDARY CONTROL after 30 seconds, with the process of correction being completed after 15 minutes with a reasonable ramp rate and without overshoot.

S3.1. **Compliance with large Program Changes**. In order to prevent unintentional FREQUENCY DEVIATIONS and major control deviations under normal operating conditions (see ⏩P1-E-C1.1), system operators are required to maintain careful compliance with times for program changes, particularly where changes in the interchange program of several hundred MW are involved. In particular, care must be taken to ensure that generating capacity is brought on line or disconnected on a staggered basis, e.g. for tariff changes at 6 a.m. and 10 p.m, and that the ramp (see ⏩P1-B-R3.7) is followed accurately. A substantial change in scheduling or the scheduled modification of power plant operation must not have a negative impact upon system operation.

S4. **K-Factor Settings.** In order to ensure that SECONDARY CONTROL will only be called up in the CONTROL AREA / BLOCK which is the source of the disturbance, all controller values for K_{ri} must match to the K-FACTORS (see ⏩P1-B-C1). In this meaning, SECONDARY CONTROL must help PRIMARY CONTROL and must not counteract it in any case. Under no circumstances should K_{ri} be modified during an incident, since this action would go against the principle of SECONDARY CONTROL.

Guidelines

G1. **Secondary Controller.** The following recommendations and guidelines are given for the setup of the SECONDARY CONTROLLER (see ⏩P1-B-R3 for the complementary requirements on the SECONDARY CONTROLLER):

G1.1. **Controller Type and Characteristic**. In case of a very large control deviation, the control parameters β_i and T_n of the SECONDARY CONTROLLER (for proportional and integral part) may be adjusted automatically for a given period of time. The control parameters β_i, and T_n are closely linked. At present, values ranging from 0 to 50% may be set for the proportional term β_i of the area controller. The time constant represents the "tracking" speed of the SECONDARY CONTROLLER with which the controller activates the control power of participating generators. Values ranging from 50 seconds to 200 seconds may be set for the time constant T_n.

G2. **Tie-Lines**. The following recommendations are given for all TIE-LINES and related equipment that may be in use for SECONDARY CONTROL (see ⏩P1-B-R5 for the complementary requirements on TIE-LINES):

G2.1. **Metering and Measurement.** All TIE-LINE measurements in MW and MWh should be telemetered to both control centres affected (and in parallel to the co-ordination centre, if necessary), using commonly agreed primary equipment (e.g. the ELECTRONIC HIGHWAY, if applicable, see ⏩P6).

G2.2. **Transmission of Measurements**. The measurements shall be transmitted in a reliable manner to the SECONDARY CONTROLLER, at least two ways are recommended, with an alarm in case of deficiency of a data transmission. The largest transmission delay must not exceed 5 seconds; it must be as small as possible and below the controller cycle time.

G2.3. Substitute Measurements. Substitute measurements and reserve equipment should always be available in parallel to the primary measurement. Substitute measurements are obligatory for all TIE-LINES with major operational impact. Accuracy and cycle times for the substitute TIE-LINE measurements must fulfil the same characteristics (see ⏩P1-B-R5).

G3. Recommended Secondary Control Reserve. In CONTROL AREAS / BLOCKS of different sizes, load variations of varying magnitude must be corrected within approximately 15 minutes. To this end, the following minimum value for the SECONDARY CONTROL RESERVE related to load variations (derived from the empirical curve shown in the figure below) is recommended for a CONTROL AREA / BLOCK:

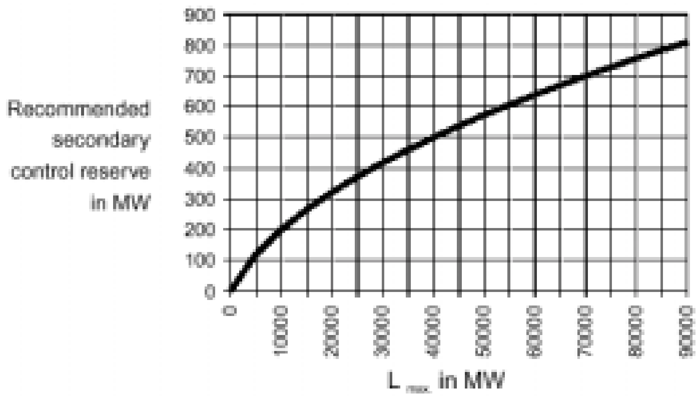
$$R = \sqrt{a\, L_{\max} + b^2} - b$$

R = the recommendation for SECONDARY CONTROL RESERVE in MW

L_{max} = the maximum anticipated load in MW for the CONTROL AREA / BLOCK

The parameters a and b are established empirically with the following values for the UCTE:
a = 10 MW and b = 150 MW

The following figure shows the recommended SECONDARY CONTROL RESERVE as a function of the maximum anticipated load:



Procedures

P1. Trumpet Curve Method. The trumpet curve method for NETWORK POWER FREQUENCY CHARACTERISTIC analysis is used after incidents, see description in detail in Appendix 1 (see ⏩A1-B).

C. Tertiary Control

[UCTE Operation Handbook Appendix 1 Chapter C: Tertiary Control, 2004]

Introduction

TERTIARY CONTROL uses TERTIARY RESERVE {15 minute reserve} that is usually activated manually by the TSOs after activation of SECONDARY CONTROL to free up the SECONDARY RESERVES. TERTIARY CONTROL is typically operated in the responsibility of the TSO. Please refer to Appendix 1 (see ⏩A1-C) for further basics and principles of TERTIARY CONTROL.

Criteria

C1. **Tertiary Control Deviation**. In case of an incident (such as ⏩P1-A-C3) that causes permanent activation of SECONDARY CONTROL RESERVES, the permanent share of the SECONDARY CONTROL is considered to be a deviation of TERTIARY CONTROL.

Requirements

R1. **Tertiary Reserve**. Each CONTROL AREA / BLOCK must have access to sufficient TERTIARY RESERVE to follow up SECONDARY CONTROL within a short period of time after an incident. An adequate control reserve must be available at all times to cover the loss of a generating unit. If the loss of the largest generating unit is not already covered by the requisite SECONDARY CONTROL RESERVE, a TERTIARY CONTROL RESERVE (minute reserve) will be required to offset the shortfall.

Standards

S1. **Activation of Tertiary Reserve**: Each TSO must immediately activate TERTIARY RESERVE in case insufficient free SECONDARY CONTROL RESERVE is available, in order to free up SECONDARY CONTROL RESERVES again.

Procedures

P1. **Activation of Tertiary Reserves**. TERTIARY RESERVES are activated by either updating the total EXCHANGES SCHEDULE of the CONTROL AREA / BLOCK (the CONTROL PROGRAM) or by changing the generation schedules within the CONTROL AREA / BLOCK.

D. Time Control

[UCTE Operation Handbook Appendix 1 Chapter D: Time Control, 2004]

Introduction

The objective of TIME CONTROL is to monitor and limit discrepancies observed between SYNCHRONOUS TIME and universal time co-ordinated (UTC) in the SYNCHRONOUS AREA (within each zone of synchronous operation of the UCTE separately). Reasonably it is applied during periods of uninterrupted interconnected operation, where the SYNCHRONOUS TIME is the same in all areas. Please refer to Appendix 1 (see ⏩A1-D) for basics and principles of TIME CONTROL.

This policy section replaces the latest "UCTE technical rule for the correction of synchronous time" (dated 01.06.1998).

Criteria

C1. **Tolerated Range of Discrepancy**. A discrepancy between SYNCHRONOUS TIME and UTC time is tolerated within a range of ±20 seconds.

C2. **Target Range of Discrepancy**. The discrepancy between SYNCHRONOUS TIME and UTC time should be within a range of ±30 seconds under normal conditions in case of trouble-free operation of the interconnected network.

C3. **Exceptional Range of Discrepancy**. Under exceptional conditions in case of trouble-free operation of the interconnected network the discrepancy between SYNCHRONOUS TIME and UTC time should be within a range of ±60 seconds.

Requirements

R1. **Time Monitor**. Each UCTE SYNCHRONOUS AREA appoints a central instance ("Time Monitor") that monitors continually the deviation between SYNCHRONOUS TIME (which is derived from the integration of the common SYSTEM FREQUENCY in this zone of synchronous operation) and the actual time (universal time co-ordinated, UTC).

R2. **Frequency Set-Point for Secondary Control.** For TIME CONTROL purposes in the range of ⏩P1-D-C3 it is required that each CONTROL AREA (see ⏩P1-A) can involve a displacement in the set-point frequency for SECONDARY CONTROL.

R3. **Frequency Set-Point for Units.** For time correction in the range of ⏩P1-D-C3 the set-point frequency of the units involved in PRIMARY CONTROL must not be changed.

Standards

S1. **Mean Frequency Value**. The mean value (as a result of PRIMARY CONTROL, SECONDARY CONTROL and TIME CONTROL in co-operation) of the SYSTEM FREQUENCY shall be the nominal frequency value of 50 Hz (see ⏩P1-A-C1), so that on average the TIME DEVIATION results to zero.

S2. **Time Deviation Calculation**. The TIME DEVIATION between SYNCHRONOUS TIME and actual time is calculated for 8 a.m. each day. The relevant time zone is the Central European Time (CET = GMT+1) with daylight saving.

S3. **Time Correction Offset**. If the TIME DEVIATION is within ⏩P1-D-C1, the offset for time correction is set to zero. If the deviation is out of ⏩P1-D-C1 and SYNCHRONOUS TIME is behind the actual time, the offset is set to +10 mHz. If the deviation is out of ⏩P1-D-C1 and SYNCHRONOUS TIME is ahead the actual time, the offset is set to –10 mHz.

S3.1. **Exceptional Time Correction Offsets**. Only under exceptional conditions out of ⏩P1-D-C3 offsets larger than 10 mHz (0.010 Hz) for the time correction of the SYNCHRONOUS TIME may be used. They are set by the time monitor.

S4. **Time Correction Standard**. The time correction offset is applied by one of the following values:

S4.1. **Frequency set-point value**. The frequency set-point value is calculated out of the sum of the nominal frequency 50 Hz and the FREQUENCY OFFSET and valid for all hours of the next day, starting at 0 a.m., and is relevant for the operation of the SECONDARY CONTROL (see ⏩P1-D-R2) and the calculation of performance criteria for SECONDARY CONTROL. All TSOs apply the transmitted frequency set-point value in their SECONDARY CONTROLLER for the full next day.

S5. **Time Correction Notice**. The information for the time correction is forwarded towards all CONTROL AREAS / BLOCKS of the SYNCHRONOUS AREA every day at 10 a.m. by the time monitor. The CONTROL AREAS / BLOCKS themselves forward this information towards their sub-control areas without delay.

S5.1. **Content of Notice.** Each notice contains the time deviation, the time correction offset, the time correction procedure and the date and duration for the time correction.

S5.2. **Notice Transmission.** This notice is transmitted using secure and reliable electronic communication that allows a half-automated procedure.

S6. **Time Correction Serialisation**. TIME DEVIATIONS and notifications on time error corrections are serialised by the time monitor on a monthly basis.

Procedures

P1. **UCTE Time Monitor**. Under normal conditions of UCTE interconnection, the ETRANS control centre in Laufenburg monitors continually the deviation between SYNCHRONOUS TIME and the actual time.

P2. **Time Correction Notice**. Under normal conditions of UCTE interconnection, the information on time correction is forwarded from Laufenburg (ETRANS) to the list of TSOs directly concerned.

P3. **Re-Connection of Asynchronous Areas**. Before re-connecting asynchronous areas of the UCTE network, the differences of TIME DEVIATIONS between the different SYNCHRONOUS AREAS need to be in target range. The smaller grid area being re-connected needs to limit this difference and to take over the synchronous time from the larger grid area once the re-connection is in operation.

P4. **Outstanding Notice.** In case the TIME DEVIATION and correction notice is missing for a TSO, the TSO applies the nominal frequency of 50 Hz (see ⏩P1-A-C1) as frequency set-point value for SECONDARY CONTROL until it receives the outstanding notice.

E. Measures for Emergency Conditions

[UCPTE Rule 15: Measures for frequency control and precautions for the decrease of the frequency value, 1965]

[UCPTE Rule: Recommendations on frequency in UCPTE interconnected operation, 1996]

Introduction

EMERGENCY SITUATIONS in the interconnected UCTE system occur as a result of abnormal operation caused by dropping of generating power, outages / OVERLOADING of transmission lines that could not be covered by the operational reserve of affected TSOs and cause imbalance of ACTIVE POWER or VOLTAGE decline. When disruptions occur, disturbances may be propagated over a vast area within a very short time. In contrast to the "Operational Security" in policy 3 (see ⏩P3), the objective of this section is to specify possible direct operational measures taken to maintain operation of the interconnected UCTE system.

The SYSTEM FREQUENCY is the main criterion for observation of normal operating conditions (see ⏩P1-A-C2). The NETWORK POWER FREQUENCY CHARACTERISTIC (see ⏩P1-A-C4) depends on the size of INTERCONNECTED NETWORKS. Considerable FREQUENCY DEVIATIONS (caused by loss of generation capacity) is more probable in small isolated systems than in a large SYNCHRONOUS AREA.

Criteria

C1. **Operating Conditions**. According to the actual SYSTEM FREQUENCY, the following operating conditions and emergency conditions are defined:

C1.1. **Normal Operating Condition / Undisturbed Operation**. If the absolute FREQUENCY DEVIATION (absolute deviation from the nominal SYSTEM FREQUENCY of 50 Hz, see ⏩P1-A-C1) does not exceed 50 mHz, operation qualifies as undisturbed (normal operating condition).

C1.2. **Impaired Operating Condition**. If the absolute FREQUENCY DEVIATION is greater than 50 mHz but less than 150 mHz, operating conditions are deemed to be impaired, but with no major risk, provided that control facilities (controllers and reserves) in the affected CONTROL AREAS / BLOCKS are for sure ready for direct deployment.

C1.3. **Severely Impaired Operating Condition**. If the absolute FREQUENCY DEVIATION is greater than 150 mHz, operating conditions are deemed to be severely impaired, because there are significant operational risks for the interconnected network.

C1.4. **Critical Operating Condition**. If the FREQUENCY DEVIATION reaches the critical value of 2.5 Hz (that means that the SYSTEM FREQUENCY reaches 47.5 Hz, for over-frequency the limit is 51.5 Hz), automatic disconnection of generators is triggered and operation of the interconnected network is at its limit.

Requirements

R1. **Load-Shedding Capabilities.** For cases of a major frequency drop, automatic devices for LOAD SHEDDING in response to a frequency criterion must be installed (see ⏩P1-A-C2.4).

R2. **Emergency Situation Declaration.** Each TSO has to declare the main characteristics of an emergency situation, for information of all undertakings involved. There must be clearly stated that emergency situation solving is a question of the highest priority at all.

R3. **Coordination.** Neighboring TSOs shall declare in bilateral operational agreements provisions for emergency assistance including provision to obtain emergency assistance from remote systems. All TSOs must co-ordinate LOAD-SHEDDING and action plans during emergency situations.

R4. **Accuracy of Frequency Measurements for Load-Shedding**. Frequency measurements for LOAD-SHEDDING must be maintained at an accuracy of approximately 5 to 10 mHz. In case that a wide triggering band will not cause severe problems in the system, an accuracy of 50 to 100 mHz is sufficient. This has to be observed and reviewed on a case-by-case basis.

R5. **Tie-lines equipment.** In order to maintain advantage and support of interconnection, TIE-LINES shall be equipped with single pole rapid re-closing devices and AUTOMATIC RECLOSING DEVICES for single phase fault.

R6. **Overload indication.** All TIE-LINES and large transformers must be equipped with devices that indicate overloads.

R7. **Equipment of Generating Units.** Depending upon system characteristics (generation mix, network requirements, etc.), a sufficient number of generating sets must be equipped with devices for the isolation of units from the remainder of the system to maintain their own auxiliaries in case of network separation, thereby allowing the more rapid reconnection and resumption of generation by these plants, once network conditions allow this. It should be avoided that the machines (after disconnection from the network) reach the emergency shut-off speed due to loss of load.

R8. **SCADA System Availability.** In case of a general loss of voltage, control centers, operating centers, substations, telecommunication systems and remote control systems must remain in operational condition, in order to allow the reconstitution of the network to be completed. Loss of a telecommunications link or an instrumentation and link between control centers, operating centers and production/transmission installations must not affect the system operation.

Standards

S1. **Maintaining Synchronous Operation.** In case of an emergency situation, the main task is to maintain synchronous operation of the UCTE system. TSOs have to take immediately all possible measures to restore normal operating conditions, subject to the available means and resources available at that time. In order to allow the support provided by TIE-LINES to be utilized as long as possible, the deliberate tripping of TIE-LINES shall be avoided, as long as interconnected operation remains possible.

S2. **Notifying Neighboring Systems.** All TSOs have to notify the neighboring TSOs in case of an emergency situation and ask for co-operation.

Guidelines

G1. **Surplus of Power.** In case of a critical increase of the SYSTEM FREQUENCY (significant surplus of power generation), power generation has to be reduced (up to the minimum) and pump operation shall be increased immediately. If the SYSTEM FREQUENCY remains at a critical value, generation units should be disconnected.

G2. **Lack of Power.** In case of a significant lack of power causing a critical drop of the SYSTEM FREQUENCY, the following actions should be performed immediately: Stop or reduction of the pump operation, increase of all running generation (up to the maximum) and connection of all possible quick-start reserves.