Power and Frequency Control Principles of Different European Synchronous Areas

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***Abstract*-This paper presents an overview of power and frequency control principles used in IPS/UPS[1] and ENTSO-E RG CE[2] synchronous areas. Power and frequency control is one of the most important issues that need to be considered for implementing the synchronous interconnection between these two systems, about which it is being talked about for quite long. The paper contrasts IPS/UPS and ENTSO-E RG CE power and frequency control norms and standards and defines the main differences and similarities between them. Finally, the main challenges to interconnect synchronously IPS/UPS and ENTSO-E RG CE systems are also discussed.**

I. INTRODUCTION

The Unified Power System of Russia (UPS) consists of 69 regional systems which themselves form 7 Interconnected Power Systems (IPS): IPS East, IPS Siberia, IPS Urals, IPS Middle Volga, IPS South, IPS Centre and IPS North West. UPS is synchronously interconnected with Azerbaijan, Belarus, Georgia, Kazakhstan, Latvia, Lithuania, Moldova, Mongolia, Ukraine and Estonia. Through the power system of Kazakhstan, UPS is synchronously interconnected with Kyrgyzstan's and Uzbekistan's power systems, the two systems of Central Asia [1].

IPS/UPS is the most extended power system in the world. It spans through out 8 time zones. Currently, IPS/UPS system has 337 GW of installed generating capacity and supplies about 1200 TWh to more than 280 million consumers.

The Regional Group Continental Europe comprises the TSOs of the former UCTE[3] synchronous area [2]. It is a system that connects 23 countries of Europe. The main purpose of the Regional Group Continental Europe (RG CE) is to pursue the reliable and efficient operation of the Continental Europe Synchronous Area [2]. At the moment, the ENTSO-E RG CE system has 631 GW of installed generating capacity and supplies electricity to 450 million people with an annual consumption of 2530 TWh.

Currently, the basic normative document that defines the principles of power and frequency control in IPS/UPS is the Standard on Frequency and Active Power Control in UPS and Isolated Systems of Russia (стандарт "Регулирование изолированно работающих энергосистемах России"). The basic document that regulates the main norms and standards of power and frequency control in ENTSO-E RG CE is the Operation Handbook. Therefore these documents have been used as a base for the analysis of similarities and differences between IPS/UPS and ENTSO-E RG CE power and frequency control.

[1] IPS/UPS – Interconnected Power System/ Unified Power System
[2] ENTSO-E RG CE – ENTSO-E Regional Group Continental Europe; ENTSO-E – European Network of Transmission System Operators for Electricity
[3] UCTE – Union for the Co-ordination of Transmission of Electricity

II. POWER AND FREQUENCY CONTROL BASIC PRINCIPLES

The frequency of a system is dependent on active power balance. As frequency is a common factor throughout the system, a change in active power demand at one point is reflected throughout the system by a change in frequency [3]. The frequency of a system decreases, if active power demand exceeds the generation, and frequency increases, if generation exceeds demand. So, there should be a balance between generation and demand in a system to keep frequency at the set-point value. The maintenace of this balance is the main task of power and frequency control.

Power and frequency control consists of four stages:

1) primary control;
2) secondary control;
3) tertiary control;
4) time control.

The objective of the primary control is to restore the balance between generation and demand after a disturbance or incident occured in a power system, using turbine governors. Primary control stabilises the system frequency, activating primary reserve during a few seconds after the occurrence of power imbalance. After 30 seconds, when the total primary reserve must be fully activated, the system frequency is stabilised at a stationary value, but without restoring its set-point value.

Secondary control is used to restore frequency at the set-point value and to eliminate the deviation of real power exchanges from scheduled ones between control areas/blocks. Also, secondary control frees up the primary reserve to restore it, activating secondary reserve in the time-frame of seconds to typically 15 minutes. However, secondary reserve must be activated only in this control area/block where imbalance between generation and demand occurred.

Tertiary control uses tertiary reserve to free up and restore secondary reserve, therefore tertiary reserve must be activated during 15 minutes after disturbance occurrence in a power system. Tertiary reserve must be able to offset the shortfall in generation if secondary reserve is not sufficient to cover the loss of the largest generating unit.

Time control limits discrepancy between synchronous time and UTC (universal time coordinated) that is caused by deviation of actual system frequency in synchronous area from the nominal frequency of 50 Hz.

III. Power and Frequency Control in IPS/UPS Synchronous Area

The approach to power and frequency control used within IPS/UPS synchronous area is a centralized control. The Unified Power System of Russia with dispatching centre in Moscow is responsible for frequency maintenance within whole IPS/UPS. At the same time, other control areas and blocks of IPS/UPS implement the frequency-biased tie-line power control. Basically, the frequency-biased tie-line power control is implemented manually by dispatchers. However, this control is implemented automatically in the Ukraine and Moldova control block and in Siberia control area. Also, the automatic power flow limitations (PFL) on indicated cross sections are performed in IPS of the Urals, IPS of Siberia, IPS of North Caucasus and in IPS of Centre.

A. Primary Control

Usually, there are distinguished two types of primary control in IPS/UPS synchronous area: general primary control and normative primary control. General primary control is performed by all the power stations in a range of possibilities of their primary control systems. The purpose of this control is to maintain the electricity supply to consumers and normal operation of power stations in case of substantial frequency deviations. Normative primary control is performed by certain power stations where the amount of primary reserve is defined in advance. Also, this reserve must always be available for use. Normative control guarantees the quality of primary control and stabilizes overall network power frequency characteristic.

The nominal frequency value in IPS/UPS synchronous area is 50 Hz. The difference between this value and the value of actual system frequency is a frequency deviation. During normal stationary operating conditions this deviation

should be no larger than $\pm$50 mHz. However, the average deviation at any 0.5 hour of the day (24 h) must not exceed $\pm$10 mHz. This requirement is used to maintain actual system frequency in a range of a static security margin of $\pm$20 mHz to avoid frequent calling up of normative primary control during normal stationary operating conditions. If the frequency deviation is larger than security margin the share of primary control reserve which is proportional to this deviation must be activated during a few seconds starting from the incident. Moreover, 50% of the total primary control reserve must be activated during 15 seconds and the rest of 50% of the reserve must be activated by up to 30 seconds after occurrence of the deviation. However, general primary control is activated if the frequency deviation exceeds its dead band of $\pm$75 mHz.

After sudden loss of generation capacity, loss of load or interruption of power interchanges the dynamic frequency deviation must not exceed $\pm$800 mHz and the quasi-steady-state frequency deviation must not exceed $\pm$200 mHz. Frequency deviation of $\pm$200 mHz is a permissable deviation level, but if the deviation exceeds this level, the entire primary control reserve must be fully activated. The frequency must be maintained in a range of $\pm$200 mHz at least during 95% of 24 hours, at the same time the frequency deviation must not exceed the maximum permissable deviation level of $\pm$400 mHz.

B. Secondary Control

As already mentioned above, the secondary control in IPS/UPS is centralized. The central secondary controller located in Moscow controls the frequency. The other secondary controllers control frequency-biased tie-line power and limit power flow on indicated cross sections.

The main regulated parameter used for seconadry control of power interchanges in IPS/UPS synchronous area is area control crror G (ACE) that needs to be controlled to zero on a continuous basis. The ACE is calculated as the sum of power control error and the frequency control error [4]:

$$G = \Delta P + K * \Delta f \,. \quad (1)$$

Where ΔP is the deviation of actual power interchanges from scheduled ones, Δf is the deviation of system frequency from the set-point frequency, K is a parameter applied to the secondary controller and $K * \Delta f$ is the frequency control error.

If ACE is not equale to zero it means that there is power imbalance in the control area/control block that leads to frequency deviation and power interchange deviation. To restore the system frequency to its set-point value and the power interchanges with neighbour control areas to their programmed scheduled values a secondary control reserve is used. The power imbalance in the control area/control block must be eliminated within 15 minutes.

To keep the ACE to zero, secondary control system must meet certain requirements. A secondary controller that performes secondary control in the corresponding control centre needs to be operated in an on-line and closed-loop manner. In the systems of automatic control of frequency and power flows there need to be used secondary controllers of proportional-integral (PI) type. The proportional factor of the PI type secondary controller may be set in a range 0 – 0.5. Also, the integration time constant may be from 50 seconds to 200 seconds for frequency and power exchange controller and from 30 seconds to 40 seconds for power limitation controller.

The cycle time for the automatic secondary controller must be no larger than 1 second to avoid time delay between occurance of disturbance and controller reaction and response to the disturbance. The transmission of measurements to secondary controller must be performed cyclically with a delay no larger than 1 second. At the same time, the accuracy of frequency measurement for secondary control must be better than $\pm$1 mHz. The accuracy of the active power measurements on each tie-line must be better than 1.0 – 2.0% of its rated value.

C. Tertiary Control

During tertiary control tertiary reserve is used that maintains and restores the necessary amount of secondary reserve. Tertiary reserve must be available at all times to provide reliable operation of secondary control and to cover the loss of the generating unit, if secondary control reserve is not sufficient for its covering. Tertiary reserve may be activated manually or automatically and its activation must begin before complete use of secondary control.

D. Time Control

Time control is performed by dispatching centre located in Moscow. Time control is used to monitor a discrepancy between synchronous time and universal coordinated time (UCT). The normally permissible range of discrepancy is ±20 seconds and the maximum permissible range of discrepancy is ±30 seconds. If at 8 a.m. every day the discrepancy does not exceed normally permissible range, the time correction is not performed. If the time error exceeds normally permissible range, the controller of synchronous time – dispatching centre in Moscow – by 10 a.m. sends commands to all dispatching centres of IPS/UPS to set the time correction offset of ±10 mHz for the next day (24 h). The time correction offset that is more than ±10 mHz is not permissible according to operational conditions of normative primary control [4].

IV. Power and Frequency Control in ENTSO-E RG CE Synchronous Area

The approach to power and frequency control used within ENTSO-E RG CE synchronous area is a decentralized control. Each control area is responsible for primary control within its territory. Also, it should maintain scheduled values of power interchanges with adjacent control areas. Control areas which work together in the secondary control function with respect to the rest of synchronous area constitute control block.

A. Primary Control

Primary control in Continental Europe synchronous area is based on principle of joint action. It means that all generators in each control area/block must react and respond to deviation in the system frequency. The contribution of each control area/block to the correction of frequency deviation is determined by its respective contribution coefficient to primary control. This contribution coefficient reflects the share of control area/block generation in total electricity generation in the synchronous area. In order to ensure that each control area/block makes its contribution to primary control, the network power frequency characteristic of each control area/block should remain as constant as possible.

The nominal frequency value in ENTSO-E RG CE is 50 Hz. In order to keep the value of actual frequency to this set-point value as closely as possible, the insensitivity of controllers that activate the primary reserve in response to imbalance between generation and demand should be as small as possible, and not larger than ±10 mHz. Therefore to avoid activation of primary reserve in undisturbed operation or at near nominal frequency, the deviation of system frequency should not exceed ±20 mHz. However, possible stationary frequency deviation in normal operational conditions may be ±50 mHz.

In case of instantaneous deviation between generation and demand (by the sudden loss of generation capacity, loss of load or interruption of power interchanges), the maximum permissible dynamic frequency deviation from the nominal frequency must be ±800 mHz. As a reference incident 3000 MW was defined for the entire synchronous area, therefore the primary reserve must be able to cover the shortfall of 3000 MW generation, without the need for customer load-shedding, and primary control must keep the dynamic frequency in a range of 50±0.8 Hz. After 30 seconds from instantaneous deviation occurrence when primary reserve is fully activated a quasi-steady-state frequency must be in a range of 50±0.2 Hz. At the same time, if the quasi-steady-state frequency deviation is of ±200 mHz or more the entire primary reserve must be fully activated. The deployment time of the primary reserve should be as small as possible and in any case 50% or less of the total primary reserve must be activated within 15 seconds and the deployment time for the rest 50% of the total primary reserve must rise linearly to 30 seconds.

B. Secondary Control

The organisation of a secondary control within control blocks in ENTSO-E RG CE systems varies and depends on a structure of the control block. If control area's boundaries coincide with control block's ones, centralised secondary control is applied in this control area/block. If a control block consists of two or more control areas, the organisational structure of secondary control within this block may be centralised, pluralistic or hierarchical. The leading TSO, who is the block coordinator, should be able to maintain the total power interchange of the block towards all other control blocks at the scheduled value.

In contrast with primary control, during which all generation sets of synchronous area provide mutual support by the supply of primary reserve, secondary control should react to a power unbalance and activate secondary reserve only within this control area/block, in which the imbalance between generation and demand has occurred. During seconary control the frequency of affected control area/block must be restored to its set-point value of 50 Hz and the power interchanges with adjacent control areas to their programmed values. At the same time, secondary control may not counteract the action of the primary control. In order to determine, whether power interchange deviations are associated with an imbalance in the control area/block concerned or with the activation of primary control power, the network characteristic method needs to be applied for secondary control of all control areas/blocks in the synchronous area. According to this method, each control area/block is equipped with one secondary controller to minimise the area control error (ACE) G in real-time [5]:

$$G = P_{meas} - P_{prog} + K_{ri}(f_{meas} - f_0). \quad (2)$$

Where $P_{meas} - P_{prog}$ is the deviation of actual power interchanges P_{meas} from scheduled ones P_{prog}, K_{ri} is a constant applied to the secondary controller and $f_{meas} - f_0$ is the deviation of instantaneous system frequency f_{meas} from the set-point frequency f_0.

The ACE must be kept to zero as close as possible. The reasons for this requirement are to maintain the balance of control area/block and not to impair the primary control action. And not to impair the primary control action under conditions of uncertainty on the self regulating effect of the load, K_{ri} for a given control area may be chosen slightly higher than the rated value of its network power frequency characteristic.

In order to control the ACE 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 [6]. To minimise the time delay between occurrence of incident and controller response to it, the cycle time for the automatic secondary controller should be between 1 second and 5 seconds. Thereby, the delay of transmission of measurements to the secondary controller must not exceed 5 seconds and it must be below the controller cycle time. Since the values of actual system frequency and active power during secondary control are monitored, the requirements to accuracy of their measurements have been set. The accuracy of measurements of active power on each tie-line must be better than 1.5% of its rated value, and the accuracy of frequency measurements must be between 1.0 mHz and 1.5 mHz.

If the control deviation occurs, the secondary reserve must be activated to return the ACE to zero. During the usage of secondary reserve that begins within 30 seconds from disturbance occurrence frequency and power interchanges return to their set point values, and this process of correction must be completed within 15 minutes. To be able to fulfil these requirements, the following minimum value for secondary reserve R is recommended in control area concerned with the maximum anticipated load L_{max} [6]:

$$R = \sqrt{aL_{\max} + b^2} - b. \quad (3)$$

Where R is the recommendation for secondary control reserve, L_{max} is the maximum anticipated load in MW for the control area/block, a and b are parameters established empirically: a = 10 MW and b = 150 MW.

According to the equation (3), for instance, secondary control reserve of 300 MW is recommended for a control area with maximum anticipated load of 20000 MW.

C. *Tertiary Control*

Tertiary control provides tertiary reserve (sometimes referred as 15 minute reserve) which is activated after activation of secondary control to free up and restore the secondary reserve. Also, tertiary reserve is required to offset the shortfall of secondary reserve, if the amount of secondary reserve is not sufficient to cover the loss of the largest generating unit. In addition, activation of tertiary reserve should distribute the secondary reserve to the various generators according to economic criteria.

D. *Time Control*

The discrepancy between synchronous time and UTC time that does not need for time correction should be within a range of ±20 seconds. Under normal conditions in case of trouble-free operation of the interconnected network the discrepancy should be within a range of ±30 seconds. The discrepancy in a range of ±60 seconds is tolerated only under exceptional conditions. The calculation of synchronous time is performed at 8 a.m. every day by the Laufenburg control centre located in Switzerland. This centre is also responsible for time correction. If discrepancy between synchronous time and UTC time exceeds a range of ±20 seconds, the information for time correction is sent to each control area/block by 10 a.m. In case of correction procedure it is set the time correction offset of ±10 mHz for secondary control in each area during the next day (24h). The offsets larger than ±10 mHz may be used only under exceptional conditions.

V. Similarities and Differences Between IPS/UPS and ENTSO-E RG CE Power and Frequency Control Principles

The Standard on Frequency and Active Power Control in UPS and Isolated Systems of Russia has been recently harmonized on the basic conceptions with ENTSO-E Operation Handbook. However, the differences between these regulating documents still exist. The main similarities and differences between the Standard and Operation Handbook that were defined in the course of analysis of these documents are considered below.

A. *Similarities*

The main criteria used to distinguish the size of frequency deviation for primary control are the same in the both systems: the primary reserve is activated if the frequency deviation exceeds ±20 mHz, the possible stationary frequency deviation in normal operational conditions may be no larger than ±50 mHz, the maximum quasi-steady-state frequency deviation must be in a range of ±200 mHz and the maximum instantaneous frequency must not exceed 800 mHz.

The requirements for the deployment times of reserves are the same in IPS/UPS and ENTSO-E RG CE systems: primary reserve must be activated during a few seconds starting from the incident. The deployment time for 50% of the total primary reserve is 15 seconds and the rest 50% of the reserve must be fully activated within 30 seconds. After full activation of the primary reserve the secondary reserve must be activated to free up the primary control. The secondary reserve must restore the set-point frequency and scheduled power exchanges during 15 minutes. If secondary reserve is insufficient, tertiary reserve must be activated during 15 minutes after occurrence of instantaneous imbalance to free up the secondary control and cover the shortfall in generating capacity.

The approach to time control is very similar in both synchronous areas: calculation of synchronous time and its correction is performed by a single dispatching centre within the synchronous area. The time correction must be performed if the discrepancy between synchronous time and UTC time exceeds ±20 seconds and all dispatching centres must set the time correction offset of ±10 mHz for the next day (24 h). However, the discrepancy in a range of ±60 seconds and the offsets larger than ±10 mHz are tolerated under exceptional conditions in Continental Europe synchronous area that is not permissible in IPS/UPS system.

B. Differences

The most important difference is in the approach to organization of frequency control. As mentioned above, IPS/UPS uses centralized philosophy of frequency control according to which the Unified Power System of Russia with dispatching centre in Moscow is responsible for frequency maintenance within whole IPS/UPS system. At the same time, ENTSO-E RG CE uses decentralized approach where each control area/block is responsible for frequency control. This difference is caused by different structure of these synchronous areas.

The different approach to organization of frequency control leads to different principles that are used for secondary control. So, the secondary control in IPS/UPS synchronous area means the control of tie-line power flows and only IPS Centre is responsible for frequency control. In ENTSO-E RG CE system secondary control always means control of ACE on control block borders.

The structure of organization of primary reserve in IPS/UPS also has its peculiarity in comparison with the structure used in ENTSO-E RG CE. There are two types of primary control in IPS/UPS system: general primary control and normative primary control. General primary control is performed by all the power stations in a range of possibilities of their primary control systems. This control applied if the frequency deviation exceeds ±75 mHz. Normative primary control is performed by certain power stations and it activates normative reserve if the deviation of system frequency exceeds ±20 mHz. In contrast to this, all generating units of ENTSO-E RG CE system have the same requirements for providing the primary reserve and all of them must take part in this process if the frequency deviation exceeds ±20 mHz.

Additionally, the requirements for the accuracy of frequency measurements and transmission of these measurements to secondary controller are stricter in IPS/UPS than in ENTSO-E RG CE. For instance, transmission of measurements to secondary controller in IPS/UPS must be performed with delay no larger than 1 second. At the same time, in ENTSO-E RG CE this delay may be between 1 second and 5 seconds.

VI. Conclusion

ENTSO-E RG CE is a huge system which is twice larger than IPS/UPS by installed generating capacity and consumption. This system connects most Western European countries. IPS/UPS is a large system geographically, but it was built to operate together, therefore it uses centralized control model. So, it will be a big challenge to interconnect synchronously the large centralized IPS/UPS system with a decentralized system like ENTSO-E RG CE.

Synchronous interconnection of IPS/UPS with ENTSO-E RG CE will create a new huge synchronous area where decentralized control structure will probably be used. Therefore, the ENTSO-E RG CE experience in connection of a large number of countries will be very useful in case of creation of this single synchronous area. However, it is important to take into account that currently there is relatively weak interconnection between IPS/UPS and ENTSO-E RG CE, therefore creation of a single synchronous area will require large investments to strengthen this interconnection.

Also, the big question is, if IPS/UPS would like to connect with ENTSO-E RG CE from frequency control point of view? As a huge number of wind parks located in ENTSO-E RG CE influences the system frequency significantly. For instance, currently there are 81 GW of installed net capacity of wind parks from 916 GW of total installed net generating capacity. Such a huge amount of installed capacity of wind parks makes frequency control challenging.

Nevertheless, frequency control models that used in IPS/UPS and ENTSO-E RG CE are compatible and they do not exclude the synchronous interconnection between these two systems.

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