INVESTICE DO ROZVOJE VZDĚLÁVÁNÍ

Power Balance Control in Electrical Grids

Učební texty k semináři

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TENTO STUDIJNÍ MATERIÁL JE SPOLUFINANCOVÁN EVROPSKÝM SOCIÁLNÍM FONDEM A STÁTNÍM ROZPOČTEM ČESKÉ REPUBLIKY

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1. SUMMARY

In any electric system, the active power generation and consumption must be balanced to prevent blackouts. Generation units and even load in some cases must be manipulated to conduct power balancing so the network user is not affected by load changes or generation and transmission outages. The Course introduces an active power balancing as a constrained control problem where design parameters are limits on manipulated variables. Basic concepts of control of synchronous generators connected to a grid will be reviewed including the technical means available for power balancing, the way how the power balancing is distributed throughout the network and who is in charge of the task. The topics include principles of primary frequency control, secondary frequency and power control, tertiary power control and balancing power reserve planning. Criteria related to successful completion of the balancing task applied to North American and European grids will be introduced. Some of the challenges in continuously evolving power systems like large wind and photovoltaic farms connected to the grid will be discussed.

The aim of the Course is to introduce the subject to graduate students, postgraduate students and post-docs of engineering as power balancing becomes an important issue when integrating other than traditional sources of energy into the grid, namely photovoltaic or wind farms.

2. Power Balancing

In any electric system, the active power generation and consumption must be balanced to prevent larger material and even human live losses as large or long lasting power deviations may ultimately lead to blackouts if the balance goes out of control. Disturbance in this balance, first noticed as a system frequency deviation, will be offset initially by the kinetic energy of the rotating turbo-generators and motors connected to the grid. Capacity of kinetic energy storing elements is insufficient for maintaining the power equilibrium in real-time. Generation units must be manipulated to conduct power balancing so the network user is not affected by demand changes or generation and transmission outages.

Secure operation of a transmission system and prevention of blackouts is an issue with rising importance for countries with deregulated electricity markets. Liberalization of electricity markets is a process that has been started and is still in progress in many countries. The basic motivation for liberalization is to enable more effective power generation as well as investment and expansion planning than it would be in traditionally vertically integrated electricity supply industry. On the demand side, end users are free to choose their supplier and to negotiate their contracts. On the supply side, producers can sell their electricity to any other market players. It is believed that this could possibly result in electricity prices drop down. However, links between physics and business practices must be carefully maintained to have enough balancing power available when required so the performance criteria of the system is guaranteed at the lowest cost possible. In another words there is the need for active power balancing mechanisms, reserve planning and purchasing, which is the task performed by a Balancing Authority (BA) responsible for power balancing in an area within the electrical grid.

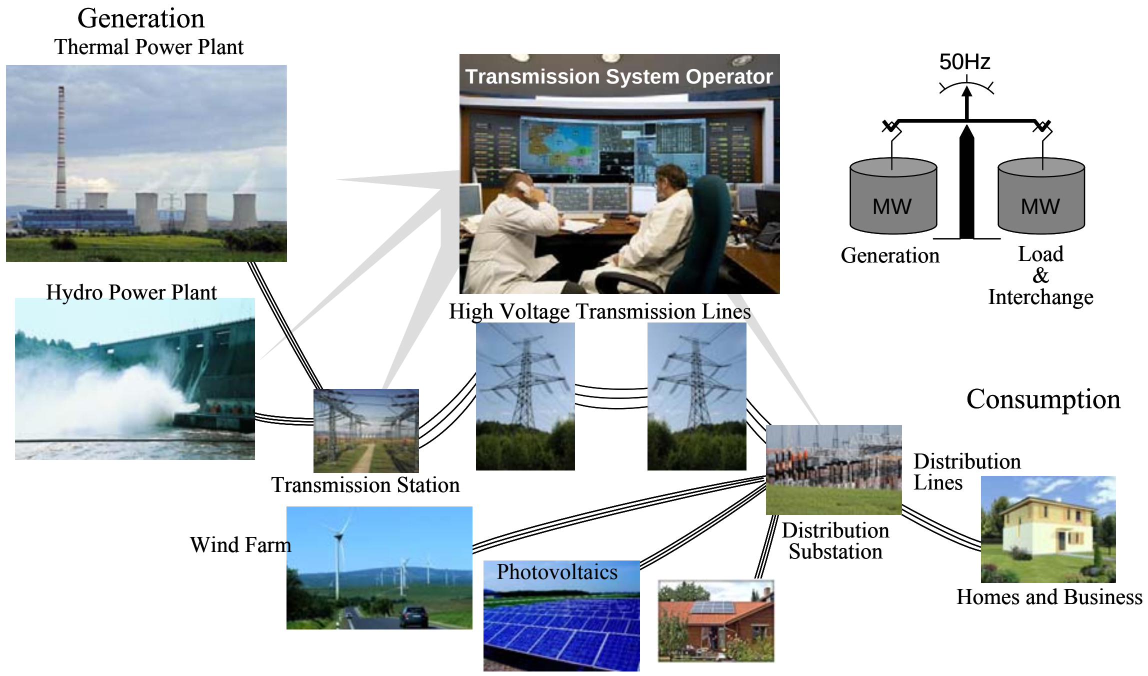

Fig. 2.1 Transmission System Operator as a Balancing Authority

BA is an electric power system or combination of electric power systems bounded by interconnection metering and telemetering. BA balances the supply and demand within their area, maintains the interchange of power with other balancing authorities and maintains the frequency of the electric power system within reasonable limits.

2.1. Power Balancing Means

Power reserves are provided by generators and distributors in the form Ancillary Services (AS). By definition, ancillary services are interconnected operations services influencing transfer of electricity between purchasing and selling entities which a Balancing Authority must include in an open access transmission tariff.

AS is a collection of secondary services offered to help to insure the reliability and availability of energy to consumers. These services include regulation, contingency reserve (spinning, supplemental – non-spinning). The contingency reserve services are often referred to as Operating Reserves.

AS provide flexible capacity to be available when needed to maintain secure operation of power system due to loss or increase of load and loss or increase of resources.

A contingency is a transmission line tripping, a generator tripping, loss of load or some combination of these events. This contingency in turn causes other problems, such as a transmission line overload, an over or under voltage in an area, over or under frequency or frequency instability. Contingency reserves are a special percentage of generation capacity resources held back or reserved to meet emergency needs.

AS arrangements vary considerably across electricity markets. Let us introduce six generic AS that are necessary for maintaining system reliability and security in electricity markets. Ancillary services required during normal conditions are continuous regulation and energy imbalance management. Instantaneous contingency reserve and replacement reserve are services used during system contingencies. Ancillary services that do not apply to active power balancing directly are voltage support and black start. The generic AS categories are described in Tab.1 more precisely.

Tab. 1 Classification of Ancillary Services

Generic AS	Description
Continuous Regulation	Provided by online resources with automatic controls that respond rapidly to operator requests for up and down movements. Used to track and correct minute-to-minute fluctuations in system load and generator output.
Energy Imbalance Management	Serves as a bridge between the regulation service and the hourly or half-hourly bid-in energy schedules; similar to but slower than Continuous Regulation. Also serves a financial (settlement) function in clearing spot markets.
Instantaneous Contingency Reserve	Provided by online resources equipped with frequency or other controls that can rapidly increase output or decrease consumption in

	response to a major disturbance or other contingency event.
Replacement Reserves	Provided by resources with a slower response time that can be called upon to replace or supplement the Instantaneous Contingency Reserve in restoring system stability.
Voltage Control	The injection or absorption of reactive power to maintain transmission system voltages within required ranges.
Black Start	Generation able to start itself without support from the grid and with sufficient real and reactive capability and control to be useful in system restoration.

Ancillary services markets are critical to power system security and reliability. This chapter assumes working with a Transmission System Operator (TSO), and an area of the Union for the Co-ordination of Transmission of Electricity (UCTE), the European system, where transmission ownership and system operation is managed by a TSO as a single authority in the control area.

The role played by the TSO in the real-time power balancing can be understood from the overall block diagram shown in Fig. 2.2 which shows the essentials of the power balancing task hiding the complexity of the very large scale power system. The control area in the center is synchronously connected to three adjacent areas A, B and C making an interconnection.

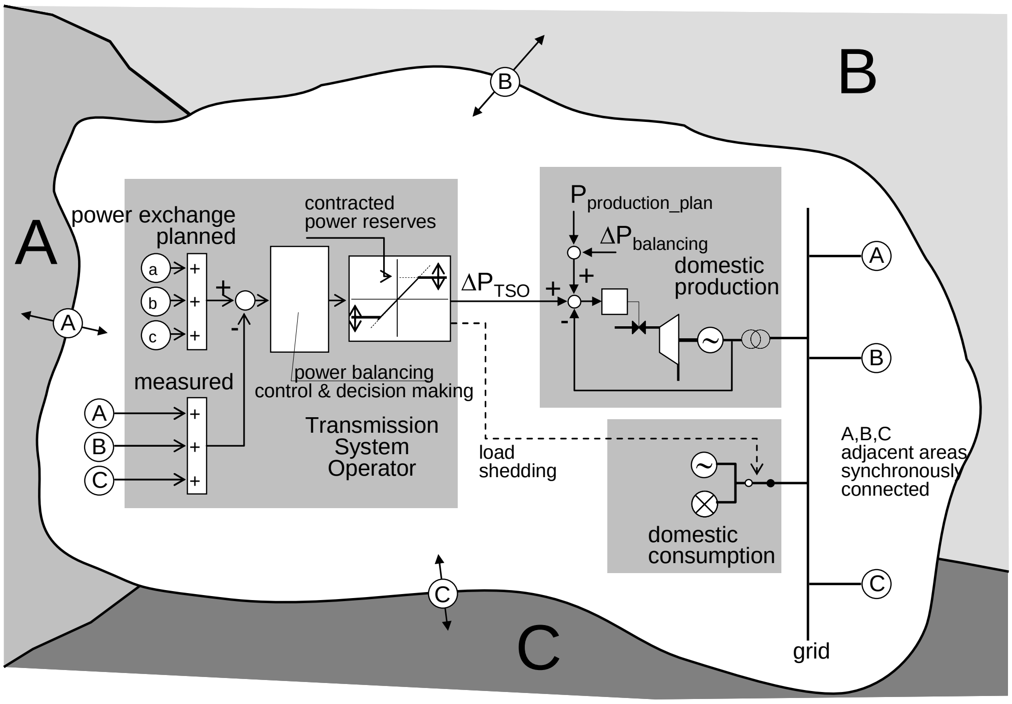

Fig. 2.2 Transmission System Operator as a Balancing Authority

The task for the TSO is to acquire enough power reserves in the form of ancillary services and activate them timely in order to guarantee that the limits set on performance indices (standards) evaluating the quality of power balancing will not be violated. The task has to be solved for the lowest cost possible. Here the subject of the chapter comes: define performance indices, describe the method used in planning and show how the planned reserves are validated. This chapter considers one year as a horizon for ancillary services planning.

2.2. Power Balancing Mechanisms within Control Area

A control area is an electric power system that is managed under a common automatic control scheme that maintains frequency by balancing load with production. Historically, a utility ran its own control area, regulating frequency, balancing its load to owned generation and purchased energy and capacity, and maintaining operating reserves as needed. Many large utility control areas served smaller in-area and near-by utilities as well. Today, some control areas exist to manage only generation, but most balance both generation and load.

To operate a large power system and to create suitable conditions for commercial electricity trade it is necessary to schedule in advance the power to be exchanged at the interconnection borders between the system operators. During daily operation, the schedules are followed by means of the load-frequency control installed in each control area. Despite the functionality of load-frequency control, unintentional deviations occur in energy exchanges. For this reason, unintentional deviations are compensated by means of the TSO in every control area.

Real-time power balancing of a control area is usually performed both by automatic control and manual interventions of a TSO's dispatch center. The entire feedback control loop of a particular control area is shown in Fig. 2.3.

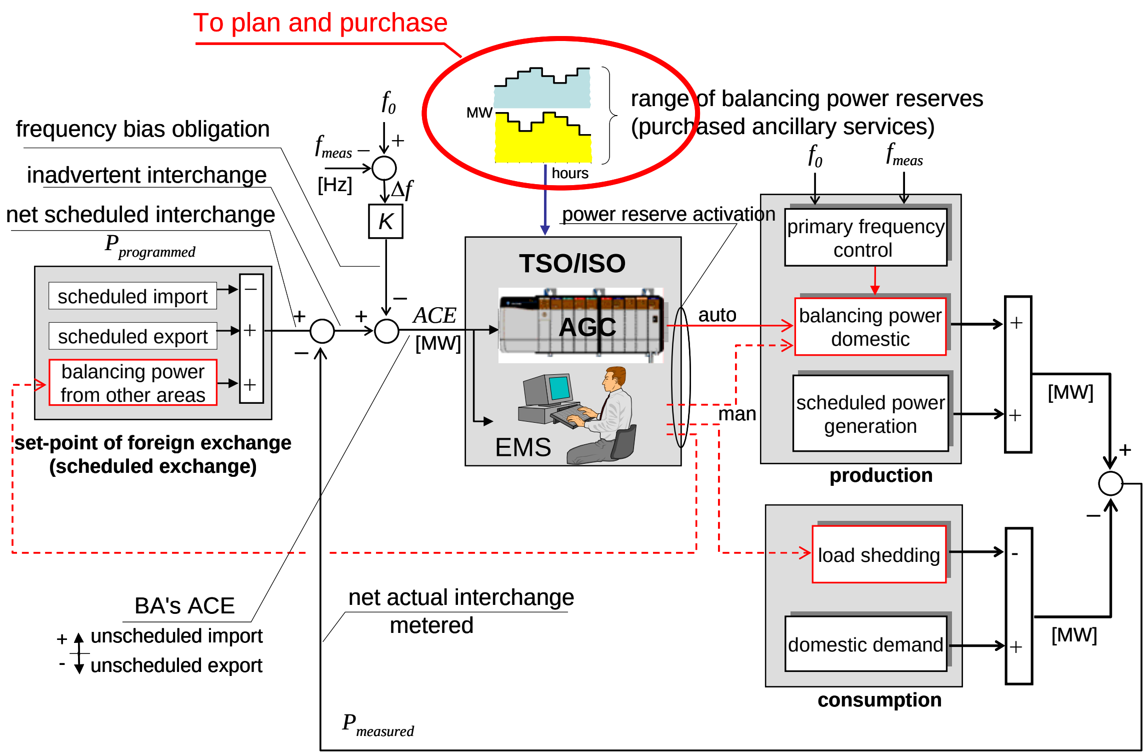

Fig. 2.3 Power balancing in the area as a feedback control system

From the control theory perspective, the controlled variable is the instantaneous value of the cross-border power exchange $P_{measured}$ that should meet its scheduled value $P_{programmed}$. Manipulated variables are represented by various categories of regulation power available in the form of ancillary services. Disturbance variables influencing cross-border power exchange can be divided into two groups: deterministic, e.g. imbalance caused by trading strategies, and stochastic, mainly random demand fluctuations and generator outages.

The input to the controller is the Area Control Error (ACE), a difference between the scheduled and actual cross-border power exchange corrected with the effect of the primary frequency control so the central controller does not compensate e.g. for outages of generators located in adjacent control areas.

The output of the central controller is increasing or decreasing power on the production side or, in the extreme case, acting on the consumption side as well. Despite the fact that the manipulated variable is active power, a single variable, we have to deal with number of outputs due to the fact that there are many actuators with different characteristics spread throughout the power system. Different turbo-generators have different control region and dynamics. Some units are in a stand-by mode and it takes some time to start them up and reach the synchronous speed. There are several modes in which the unit control system can run. Thus every producer can offer the TSO certain amount of power reserve in several categories of AS. The TSO defines the portfolio of ancillary services which might differ from country to country, state to state, or area to area, and runs AS market where a TSO purchases balancing power reserves for potential use. An example of AS we deal with in this chapter when explaining one method of AS planning provides Tab. 2.

Tab. 2 An example set of ancillary services and their categories

Generic AS		Preferred use	Area specific AS identifier	Response time
Continuous regulation	spinning	Primary frequency control	RZPR	~30 sec
Continuous regulation	spinning	Secondary power and frequency control	RZSR	≤ 15 min
Energy imbalance management	spinning	Load following	RZTR$^+$	≤ 30 min
			RZTR$^-$	
Instantaneous	non-	Operating reserve	RZQS	≤ 15 min

contingency reserve	spinning			
Replacement reserve	non-spinning	Dispatch reserve	$RZN_{>30}$	> 30 min

Ancillary services activated automatically are primary and secondary controls. The functionality of primary frequency control, or rather activation of active power reserve RZPR, is distributed throughout the control area being part of a speed governor control system operating in droop control mode.

Activation of secondary power reserve is conducted by the central TSO's control system. This scheme is associated with the term Automatic Generation Control (AGC) which means the automatic adjustment of a Control Area's generation from a central location to maintain its interchange schedule plus frequency bias. AGC is also known as a load-frequency controller. Generators under secondary control (UCTE) must reach the demanded increase/decrease in power output within 10 minutes at a rate at least 2 MW/minute.

The remaining AS used predominantly for energy imbalance management and during contingencies are dispatched by the TSO manually.

Let us define basic terms before describing the methodology for AS planning.

2.2.1. *System Frequency*

The electric frequency in the network, the system frequency f, is a measure for the rotation speed of the synchronized generators. By increase in the total demand the system frequency will decrease and vice-versa. Turbine speed controller is performing automatic primary control action to balance demand and generation. The frequency deviation Δf is influenced by both the total inertia in the system, and the speed of primary control. Under undisturbed conditions, the system frequency must be maintained within strict limits in order to ensure the full and rapid deployment of control facilities in response to a disturbance.

2.2.2. *Primary Frequency Control*

The objective of primary frequency control (PR) is to maintain a balance between generation and consumption within the synchronous area using turbine speed or turbine governors. PR is an automatic function distributed throughout the network. When the generator is part of a large power system, and electric generation is shared by two or more machines, the frequency (speed) cannot be controlled to remain constant because it would forbid generation sharing between various synchronous generators. Control with speed droop is the solution that allows for fair generation sharing.

PR stabilizes the system frequency after a disturbance in seconds. The control law is in principle proportional and the controlled system does not have the integral character. The result is the steady state error in system frequency and, in addition, power exchanges between areas are not restored. By the joint action of all primary controllers, PR ensures the operational reliability for the power system of the synchronous area, stabilizes frequency but cannot drive the system frequency back to the original setpoint value and cannot restore cross-border power exchanges in the interconnected system so they will differ from values agreed between parties.

The overshoot or undershoot of the system frequency is a function of the amplitude and dynamics of the disturbance affecting the balance between power output and consumption, the kinetic energy of rotating machines in the system, the number of generators subject to PR, i.e. the primary control reserve and its distribution between these generators, the dynamic characteristics of the machines and their control systems, and the dynamic characteristics of loads, particularly the self-regulating effect of loads.

The steady state error of the system frequency is a function of the amplitude of the disturbance and the gain of the proportional controller which is associated with so called network power system frequency characteristic.

Starting from undisturbed operation of the UCTE network [2], a sudden loss of 3000 MW generating capacity must be offset by primary control alone, without the need for customer load-shedding in response to a frequency deviation. In addition, where the self-regulating effect of the system load is assumed according to be 1 %/Hz, the absolute frequency deviation must not exceed 180 mHz. Likewise, sudden load-shedding of 3000 MW in total must not lead to a frequency deviation exceeding 180 mHz.

Primary control reserve for the entire synchronous area *RZPR*, also referred to as a continuous regulation reserve, is determined by the required performance described above, taking into account measurements, experience and theoretical considerations. The share $RZPR_i$ of the control area i is defined by multiplying the calculated reserve for the synchronous area and the contribution coefficient C_i of the control area:

$$RZPR_i = RZPR \cdot C_i \,, \tag{2.1}$$

where the contribution coefficient C_i is calculated on a regular basis for each control area, or TSO, using the following formula:

$$C_i = \frac{E_i}{E} \,, \tag{2.2}$$

where E_i is the electricity generated in control area i and E is the total electricity production in all control areas of the synchronous interconnection.

A deviation in system frequency Δf will, in the steady state, release primary control power throughout the synchronous area ΔP_{PR} as follows

$$\Delta P_{PR} = \lambda \, \Delta f \,, \tag{2.3}$$

where the gain λ is called a power system frequency characteristic of the synchronous area and λ is the sum of power system frequency characteristics of all areas synchronously connected.

Every TSO is required maintaining a network power-frequency characteristic λ_i of the control area derived from the power-frequency characteristic designed for the overall synchronous area λ and the area contribution coefficient C_i

$$\lambda_i = C_i \lambda \,. \tag{2.4}$$

Each interconnected TSO must activate primary control power adequate to the system frequency deviation Δf using

$$\Delta P_{PR\,i} = \lambda_i \Delta f \,, \tag{2.5}$$

where ΔP_{PRi} is the power variation generated locally in the control area in response to a frequency deviation caused by a disturbance, e.g. generation unit outage.

Fig. 2.4 shows the principle of the primary control loop for the area. Note that the index of the area *i* is omitted from all power variables and λ for simplicity. The block diagram should be actually further split into control loops of individual turbo-generators as shown in Fig. 2.5. Generating units should deliver programmed (contracted) active power and provide power balancing functionality through primary, secondary and tertiary control at the same time. The programmed power is thus modified locally by primary frequency control independently on all other means of power balancing used centrally by the TSO.

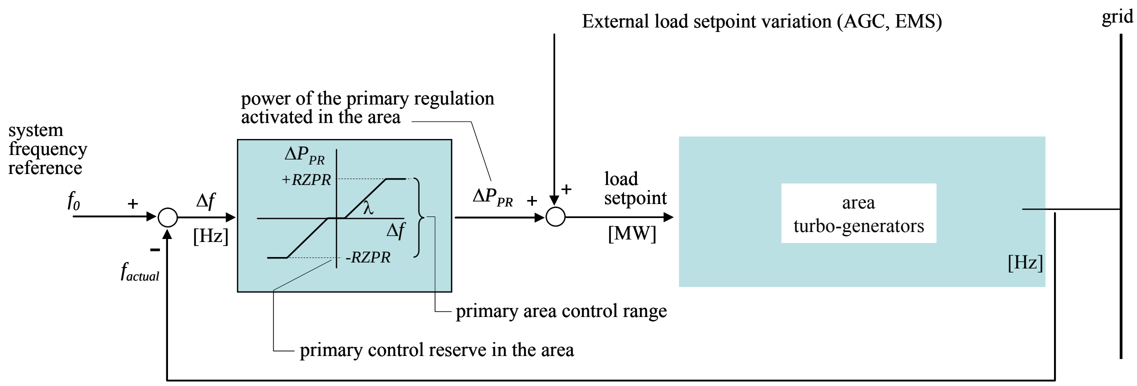

Fig. 2.4 Principal diagram of the primary frequency control loop in the area

Primary control is performed by the speed governors of the generating units. With primary control, a variation in system frequency greater than the dead band will result in a change in unit power generation. Generators are required to participate in this control by setting the droop, which is directly related to the gain of the speed governor in Fig. 2.5, according to specifications defined by the TSO. Transients of primary control are in the time-scale of seconds.

Power engineering is an area where different disciplines use different words for the same function and many of power engineers get frustrated when the literature fails to define or mention the terms *droop*, *isochronous* or *speed/load* which refer to generator control [3]. Here are few examples.

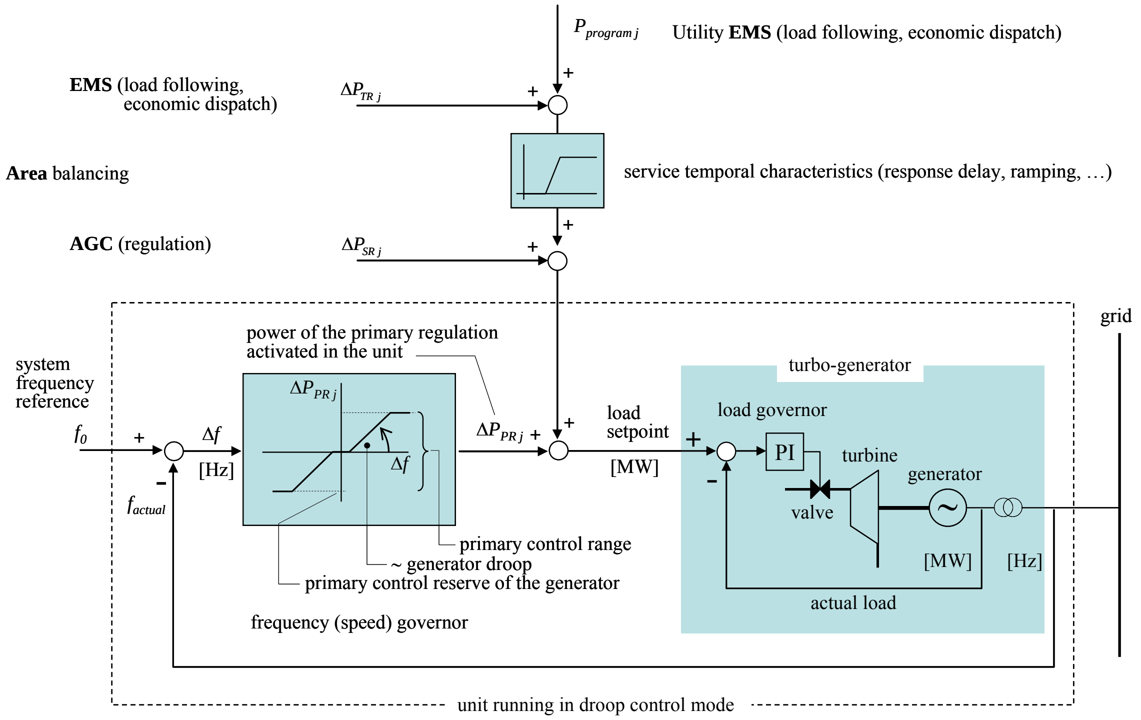

Fig. 2.5 Principal diagram of the primary frequency control loop for generating unit

Rotating equipment people refer to *droop* control. The governor droop characteristic of a generation unit is given by the ratio of frequency deviation (% with respect to nominal frequency) needed to change generation power output (% with respect to nominal output) multiplied by 100. For example, a 5% droop means that a 5% frequency deviation causes 100% change in power output. However controls or instrumentation specialists would call this *proportional* control and might not even recognize the term *droop*. Frequently, utilities or power house people will refer to this as *speed/load* control and may not recognize either of the other terms.

By the same token, people with a rotating equipment background will refer to *isochronous* control. Control engineers will call this *PID* control and utilities or powerhouse people will use *frequency* or *speed* control for the same thing.

Synchronous generator is operated in frequency (isochronous) control mode when disconnected from the grid and switched to droop control when synchronized and connected to the grid. On a small electrical grid, one machine is usually operated in isochronous speed control mode, maintaining system frequency using PID control loop. Any other (usually smaller) generators which are connected to the grid are operated in droop speed control mode, running under P control. If two prime movers operating in isochronous speed control mode are connected to the same electrical grid, they will usually "fight" to control the frequency, and wild oscillations of the grid frequency usually result. Only one machine can have its governor operating in isochronous speed control mode for stable grid frequency control when multiple units are being operated in parallel.

On very large electrical grids, commonly referred to as "infinite" electrical grids, there is no single machine operating in isochronous speed control mode, which is capable of controlling the grid frequency; and all the prime movers are being operated in droop speed control mode. But there are so many of them and the electrical grid is so large that no single unit can cause the grid frequency to increase or decrease by more than a fraction of a percent as it is loaded or unloaded.

Very large electrical grids require system operators to quickly respond to changes in load in order to control grid frequency properly since there is no isochronous machine doing so. Usually, when things are operating normally, changes in load can be anticipated and additional generation can be added or subtracted in order to maintain tight frequency control.

One method many electrical grid operators use to control grid frequency is an Automatic Generation Control (AGC). Units being operated in AGC get their Droop Speed Control speed setpoints (frequency f_0) adjusted remotely in response to commands from the system operator(s) to maintain grid frequency. AGC is going to be described in the next section.

2.2.3. *Secondary Frequency and Power Control*

Secondary control (SR) drives the system frequency and cross-border power exchanges back to the original desired (programmed) values after 15 to 30 seconds if the activated power does not reach the saturation limit of the reserve acquired. To prevent reaching the saturation and loosing the functionality of the secondary control an additional power should be released to the system through activating other than primary balancing power reserves.

Transients of secondary control are in the order of minutes. Secondary control is also called Automatic Generation Control (AGC). In addition, AGC distributes the imbalance between selected units in an economical way. AGC is usually provided by the area's balancing authority, the TSO in the case of the UCTE interconnection. Generation scheduling and control is an important component of daily power system operation. The overall objective is to control the electrical output of generating units in order to supply in an economical manner the continuously changing customer power demand. Much of this functionality is provided by AGC run by balancing authority (TSO) and related functions operating within a utility control centre Energy Management System (EMS).

Fig. 2.6 shows the block diagram of the automatic SR control system whose function is realized by the TSO.

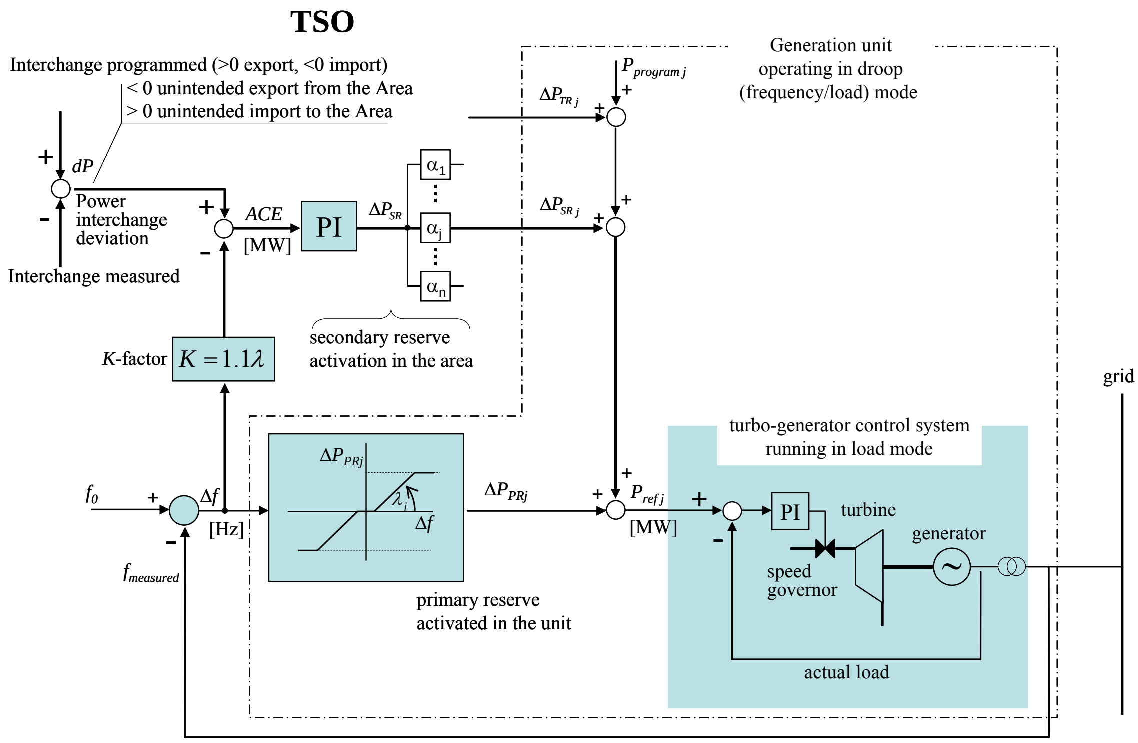

Fig. 2.6 Principal diagram of the secondary frequency and power control loop

The output signal of the secondary PI controller ΔP_{SR} is distributed over participating generators with participating factors α_1, … α_n.

The function of SR, also known as load-frequency control or frequency-power-control, is to keep or to restore the power balance in each control area and, consequently, to keep or to restore the system frequency *f* to its set-point value and the power interchanges with adjacent control areas to their programmed scheduled values. This will ensure that the full reserve of primary control power *RZPR* will be recovered.

Whereas all control areas of the interconnection participate providing primary control power, only the control area affected by a power unbalance is required to undertake secondary action for the correction. Parameters for the secondary controllers are set such that only the controller in the zone affected by the disturbance concerned will respond and initiate the deployment of the requisite secondary control power. Within a given control area, the demand should be covered at all times by electricity produced in that area including electricity imports (under purchase contracts and/or electricity production from jointly operated plants outside the zone concerned). Secondary control is applied to selected generator units in the power plants comprising the control loop.

Since it is technically impossible to guard against all random variables affecting production, consumption or transmission, the volume of reserve capacity will depend upon the level of risk which is acceptable. These principles will apply, regardless of the distribution of responsibilities between the parties involved in the supply of electricity to consumers.

In order to determine, whether power interchange deviations are associated with an imbalance in the control area concerned or with the activation of primary control power, the corrective term should be introduce to power interchange deviation. This is known as network characteristic method and its function is shown through the K-factor link in (2.6). Due to the uncertainty on the self regulating effect of the load, the K-factor K_i may be chosen slightly higher than the rated value of the power system frequency characteristic λ_i such that the SR will accentuate the effect of the PR. Each control area is equipped with one secondary controller to minimize the ACE in real-time:

$$ACE = P_{programmed} - P_{measured} - K\left(f_0 - f_{measured}\right) \qquad (2.6)$$

where $P_{measured}$ is the sum of the instantaneous measured active power transfers on the tie-lines, $P_{programmed}$ is the exchange program with all the adjacent control areas, K is the K-factor of the control area, a constant (MW/Hz), f_0 is the setpoint and $f_{measured}$ is the instantaneous measured system frequency.

The *ACE* is the control area's unbalance $P_{programmed}$ - $P_{measured}$ with hidden effect of the area's primary control. There might be different sign convention for *ACE* relative to the respective TSO. In this chapter the power transits are considered positive for export and negative for import. Hence, a positive (respectively a negative) *ACE* requires an increase (resp. decrease) of the secondary control power. The *ACE* must be kept close to zero in each control area at all times.

The secondary controller is implemented as a PI controller with additional features such as anti-windup and rate limiting.

The secondary control range *RZSR* is the range of adjustment of the secondary control power ΔP_{SR}, within which the secondary controller can operate automatically, in both directions (positive and negative).

In control areas of different sizes, load variations of varying magnitude must be corrected within approximately 15 minutes. The size of the *RZSR* required depends on the size of typical load variations, schedule changes and generating units. The minimum value for the *RZSR* related to load variations in MW is recommended using the empirical formula

$$RZSR = \sqrt{aL_{\max} + b^2} - b \tag{2.7}$$

where L_{max} is the maximum anticipated load in MW for the control area, and parameters a and b are established empirically with the following values for the UCTE: a = 10 MW and b = 150 MW.

If the consumption exceeds production in longer periods, immediate action must be applied using tertiary control, standby supplies, or contractual load shedding as a last resort.

Secondary reserve is also referred to as a continuous regulation reserve.

2.2.4. *Tertiary Reserve*

Active power ΔP_{TR} of a tertiary reserve *RZTR* is usually activated manually by the TSO to free up exhausted secondary reserve so that it can effectively reject common fluctuations. Tertiary control action is a signal sent by the TSO to the producer, whose generating unit is included in the tertiary control scheme, requesting changing control range of the unit e.g. by changing the operating point of the boiler. This usually takes some time and frequency of these moves is also limited. The function of the tertiary control can be viewed as a dynamical change in the active power setpoint which in turn moves the use of secondary control reserve away from its limit value. The reserve denoted $RZTR^-$ is used for output decrease and $RZTR^+$ for output increase.

Tertiary control is an economic dispatch. It is used to drive the system as economically as possible and restore security levels if necessary.

AS provider must provide the requested portion of the regulating reserve within a specified time limit, e.g. 30 minutes, and at a specified minimum rate, typically 2 MW/min.

Tertiary reserve belongs to the category of a load-following spinning reserve.

2.2.5. *Quick Start Reserve*

Quick-start reserve *RZQS* is usually provided by pumped-storage power stations that are able to start generation within 10 min. The preferred use of *RZQS* is to compensate for large and sudden deviations due to generator outage. This reserve is activated manually from the TSO's control center. As the capacity of water reservoirs is limited the use of the quick-start reserve is restricted in time.

Quick start reserve is also referred to as a contingency non-spinning reserve.

2.2.6. *Stand-by Reserve*

Stand-by reserve *RZDZ* is typically represented by combined-cycle gas-turbine generation units. Depending on their capability of reaching its nominal output within the agreed time they may be in the category RZN_{30}^+ or $RZN_{>30}$. The stand-by reserves are typically activated in the case of a generator outage or a longer-lasting deficit of energy in the system caused by some other reasons.

Stand-by reserve falls into the category of a contingency replacement (supplemental) reserve.

2.3. Planning Reserves

There is a lot of constraints that must be considered when planning reserves. The following non-usable capacity must be taken into account in the calculation of capacity needed to meet power requirements: units subject to long-term shutdown; units shut down for repair and maintenance; limits on capacity associated with restrictions in fuel supplies; limits on capacity associated with environmental restrictions; limits on the capacity of hydroelectric plants associated with hydraulic and environmental constraints; the primary control reserve; reserves to cover variations in production and consumption (secondary and tertiary reserves).

In addition to these factors, which are directly associated with production, account must also be taken of system conditions, given that network constraints may reduce scope for the transmission of power produced.

From the TSO point of view, a support system for AS planning should read reliability requirements on power balance control and give recommendations for optimal composition of the AS, which the TSO should acquire on the market. In particular, the system should be able to answer the following questions:

- What amount of reserves in the form of the AS are needed in each category to ensure power balancing with desired reliability.
- What is an expected offer of the AS from providers on the market in terms of their volumes and price.
- How to select the AS from the offer to cover the needs in the optimal way.
- What are expected costs associated with a certain level of reliability of transmission system operation.

Similar tasks have emerged in all countries that have gone or are going through the liberalization process. From the global point of view, safe operation of a transmission system can be viewed as a multi-criteria optimization task. Due to a strong interaction between technical and economic consequences of the planning and operation decisions the two basic competing criteria, quality of electricity and costs of the transmission system operation, have to be regarded simultaneously.

Optimal planning of the AS involves market modeling. Three main modeling trends are identified: optimization models, which focus on a profit maximization problem for one of the players competing on the market, equilibrium models, which represent overall market behavior taking into consideration competition among all participants, and simulation models, often based on multi-agent systems, which are an alternative to the equilibrium models when the problem under consideration is too complex. The models use a variety of computational techniques: linear programming, mixed integer programming, dynamic programming, non-linear programming, heuristic approaches and others.

Many papers focus on pricing and optimal procurement of the energy and AS. If the market products (energy and AS) are procured simultaneously through central (usually day-ahead) auctions, the task to solve is to simultaneously co-optimize energy and AS ensuring the least costs and safe operation of the transmission system, which includes issues such as solving optimal power flow, unit commitment, congestion management and emission constraints [4, 5, 6, 7, 8]. The market products may be procured sequentially through the central auctions managed by the ISO/TSO, usually in the following order: energy market, transmission market to resolve congestions (if needed) and market for each category of the AS (from the fastest-response to the slowest-response service). In such a case the problem arises how to optimally purchase AS taking into account the downward substitutability of the AS since a market clearing price in each of the markets depends on the demanded volume.

However, the complex task of optimal planning of AS is still challenging. Although methods solving some of the partial subtasks exist, they have to be carefully chosen and modified to fit in the context of a specific country or region. The inner structure of the global AS planning problem may also vary from country to country.

Let’s assume that the generation portfolio of a particular control area consists of dozens 110 MW and 200 MW, some 500 MW and 1000 MW generation units and the peak load is approximately 11 GW. Let’s assume a dense network so no inner flow congestion management is needed, only for cross-border tie lines capacity auctions will be organized.

Such control area will be a part of European synchronous interconnection (UCTE), and as such, its operation must comply with the UCTE rules [2] and relevant legislation, which, among others, lays down TSO liability for frequency and power balance maintenance. For this purpose the TSO purchases most of AS through free-market tenders organized typically for 3 years and 1 year periods. The TSO spends money only on AS reservation (purchase), costs for AS activation are covered later by market participants that cause power imbalance. Hence, in the rest of the chapter, by "AS cost" we understand the cost of reservation.

Energy markets are separate from AS markets. Most energy is traded in the form of bilateral contracts for base-load products on a year-ahead basis. Peak-load products are mainly subject of short-term energy markets. Assume that the TSO is not allowed to participate in energy markets.

3. Performance Criteria

Different interconnections may have chosen and use slightly different performance criteria for evaluating the reliability of system services in terms of power balancing.

3.1. North America

North American Electric Reliability Corporation (NERC) defines three Control Performance Standards (CPS) for the assessment of a control areas generation control performance: CPS1, CPS2 and DCS [4]. All control areas in North America implemented CPS in 1998.

CPS1

Each Balancing Authority shall operate such that, on a rolling 12-month basis, the scaled average of clock-minute averages of the *ACE* of the area multiplied by the corresponding clock-minute averages of the interconnection's frequency error is less than a specific limit. The index of the area *i* will be omitted throughout the rest of the chapter for simplicity as the discussion concerns just a single area of the interconnection.

CPS1 is a statistical measure of ACE variability. CPS1 measures *ACE* in combination with the interconnection's frequency error. The CPS1 requires that the average of the clock-minute averages of a control area's *ACE* over a given period divided by its K-factor times the corresponding clock-minute averages of the frequency error shall be less than a given constant

$$\mathrm{AVG}_{\mathrm{Period}}\left[\frac{ACE}{K_{area}}\Delta f\right] \leq \varepsilon_1^2 . \qquad (3.1)$$

The constant ε_1 is derived from the targeted frequency bound (the targeted RMS value of one-minute average frequency error based on frequency performance over a given year). For the purpose of the control performance evaluation the CPS1 is evaluated monthly for a past (sliding) twelve-month period. CPS1 is measured in MW·Hz.

CPS1 measures control performance by comparing how well a control area's *ACE* performs in conjunction with the frequency error of the interconnection. The criterion (3.1) can be viewed as a correlation between *ACE* and Δf. Positive correlation means undesired performance (the area control error contributes to the frequency deviation from the desired value) and is therefore limited by the upper bound ε_1^2. Negative correlation occurs when *ACE* helps to compensate the total *ACE* of the interconnection and is helping to offset the system frequency deviation.

CPS2

The other criterion, CPS2, is designed to bound ACE ten-minute averages and provides an oversight function to limit excessive unscheduled power flows that could result from large ACE:

$$\mathrm{AVG}_{10\_\mathrm{minute}}(ACE) \le \varepsilon_{10}\sqrt{K_{area}K_{interconnection}} \tag{3.2}$$

where $K_{interconnection}$ is the sum of K-factors in the entire interconnection and ε_{10} is the targeted RMS of ten-minute average frequency error. Each Balancing Authority shall operate such that its average *ACE* for at least 90% of clock ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10}. Extensive analysis and further discussions on the two performance indices can be found in [4, 5, 6, 7].

NERC does not have the statutory authority to enforce compliance with its reliability standards. Despite its lack of authority, NERC has made every effort to continuously clarify and upgrade its reliability standards as the electric industry has evolved. NERC has also enhanced its monitoring of compliance with its standards by individual entities, independent system operators, and Regional Reliability Councils.

Each control area can meet the CPS standards by any means they wish. A control area can possibly use current control schemes, chase its generating obligations manually or implement other control schemes.

A control area not meeting the CPS is not allowed to sell control services to other parties external to its metered boundaries. This impacts those purchasing control services from this control area. This is a significant penalty given new operating environments.

Benefits of CPS: technically defensible, allow smarter control by reducing unit maneuvering, more accurate assessment of control area performance, reduces generating unit operating and maintenance costs, ability to monitor and control frequency performance, allow less restrictive short-term performance requirements in exchange for more restrictive long-term requirements.

DCS

The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its contingency reserve to balance resources and demand and return interconnection frequency within defined limits following a reportable disturbance. Because generator failures are far more common than significant losses of load and because contingency reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

A disturbance is defined as any event that is ≥80% of the magnitude of the control area's most severe single contingency. A control area is responsible for recovering from a disturbance within 10 minutes by recovering the amount of the disturbance or returning ACE to zero. A disturbance is not reportable if it is greater than the control area's most severe contingency.

Control area must comply with the DCS 100% of the time. Any control area not complying are required to carry additional contingency reserve. Extra reserves must be carried for the quarter following the quarter in which the non-compliance occurs.

3.2. Europe (UCTE)

According to the UCTE Operation Handbook [6] the individual ACE_i needs to be controlled to zero on a continuous basis in each control area. In addition, frequency deviation should decay to the given setpoint in less than 15 minutes and any power outage should be compensated accordingly. Both large and/or long lasting ACE deviations should be avoided as much as possible.

These general quality requests will be specified in more rigorous way in section 3.3 working with $AVG_{1\_minute}(ACE)=ACE_1$, $AVG_{1\_hour}(ACE)=ACE_{60}$ and other indices, in order to be used as performance criteria and power balancing quality indices. A soft constraint L_1 and L_{60}, similar to L_{10} for NERC's CPS2 will be used.

Some of the requests could be represented by a mean value of *ACE* that should be kept at zero and a standard deviation of *ACE* should be kept low. The mean and the standard deviation of *ACE* is used sometimes for comparing operations of control areas of a single interconnection [15].

Setting the limit values of the selected performance indices is a delicate task. In general, if the limits are set too high, larger and/or longer lasting power imbalances are assumed to be allowed. On the other hand, setting the limits too low may request the amount of balancing power reserves that is simply not available in the respective category in the area and/or reserving the power becomes inadequately expensive.

In the following section, the task and the principle of the algorithm for AS planning is described.

3.3. Czech Republic

In order to determine power reserves in the form of AS, which would technically suffice for proper power balance control with acceptable reliability, it is necessary to refer to reliability standards. Since the UCTE has no specific reliability standards for its members, particular indices describing reliability are defined in CZ Grid Code for this purpose. Each of them is representing a probability that ACE exceeds a certain threshold and lasts for a certain time (Value-at-Risk). The index $rACE_1$ refers to 1 minute average value of ACE while the index $rACE_{60}$ refers to an average value of ACE over one hour.

$rACE_1$ and $rACE_{60}$ are statistical measures of ACE having a relation to NERC's CPS2. $rACE_{1t}$ is linked to a UCTE requirement on frequency recovery in less than

15 min. after a forced generation unit outage and thus it is similar to NERC's DCS index.

The desired values were determined statistically from historical records of ACE. Few consecutive years should be evaluated. Duration of the period assigned for statistical evaluation should correspond to a period when technical parameters of the transmission system and market conditions are compatible with the current situation and practice. In addition, no problems related to the area performance should be reported neither from adjacent area TSOs not from the domestic customers. Hence, we may assume that the TSO's performance was satisfactory.

The indices are direct measures for quality of power balance control in the control area and indirect measures for reliability of power supply to end-consumers.

Tab. 3 Selection of reliability indices based on Area Control Error time series evaluation

Performance index	Limit value	Description
$rACE_1$	3,2 %	probability that the absolute value of one-minute average of *ACE* exceeds L_1 = 100 MW
$rACE_{60}$	4,6 %	probability that the absolute value of one-hour average of *ACE* exceeds L_{60} = 20 MW
$rACE_{1t}$	0,027 %	probability that one-minute average of *ACE* is higher/lower than ±100 MW for a period longer than 15 minutes

4. Ancillary Services Planning

Every ISO/TSO might adopt different AS planning procedures depending on interconnection and control area specificity. What make the problem more difficult are recent changes in market structures so there is a lack of long term experience in effective AS planning. The principles adopted in the method described in this section might serve as a basis for a general platform adopting various criteria and constraints despite the fact that the approach was developed for one control area of the UCTE interconnection. The method is currently being used by the TSO of the Czech Republic as a support tool and is described in [8] in greater detail.

The entire AS planning task can be decomposed into several subtasks depicted in Fig. 4.1 that are executed in the order indicated by the respective block numbering.

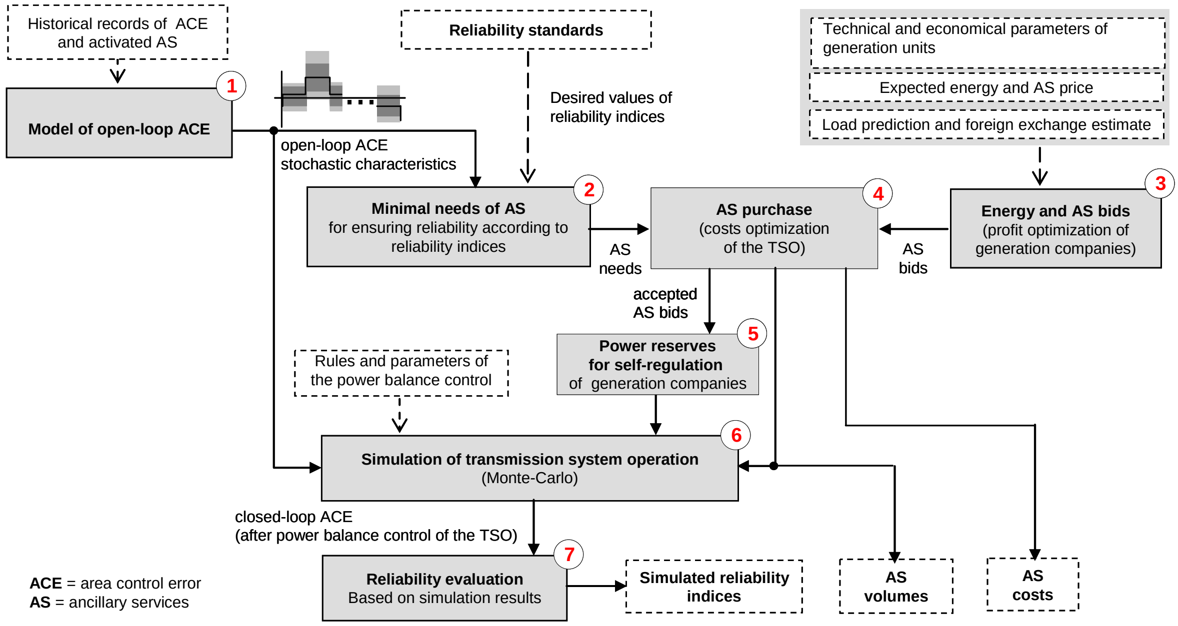

Fig. 4.1 Block diagram of ancillary services planning and validating procedures

The control area is viewed as a pool. First the ACE of the area is modeled as if it would run without AGC and EMS actions used centrally by the TSO (step 1). Various horizons might be considered. One year is assumed in the reminder of the chapter. Variability of such an "open-loop ACE" is high. Considering the control and disturbance performance standards, the request for AS decreasing ACE's variability is calculated (step 2). If the availability of the AS is not limited and the cost of AS is not an issue, the algorithm proceeds in running the M-C simulation of the area which includes TSO's AGC and EMS actions, and gets ACE statistics. Ones having ACE time series, any performance indices and conditions introduced by respective standards can be evaluated including NERC's CPS2 and DCS.

In reality, AS is a commodity and the TSO has to go to the market, compare the offerings to what is needed to meet the performance standards and consider the AS price when purchasing. The initial plan for AS might not be feasible now as some of the services needed are not offered in sufficient amount. However, there is some freedom in restructuring the needs as some slower services can be substituted by faster ones. This leads to Linear Programming problem having the aim of minimizing the cost of the purchase and meeting the performance standards at the same time. AS bids are calculated (step 3) and optimal purchase is carried out replacing the originally assumed set of AS by the feasible and cost optimized one (step 4).

Next sections briefly review the procedure. More details can be found in [8].

4.1. Stochastic Model of Area Control Error

The "open-loop ACE" is considered as a random process with characteristics related to the recent history of control area operation. The open-loop ACE, ACE_{OV}, can be decomposed into two components:

$$ACE_{OV} = P_V + ACE_O\,. \tag{4.1}$$

P_V represents forced generation unit outages and will be modeled as a Markov process parameterized by mean time between failures and duration of repairs.

ACE_O accounts for other phenomena, for instance a mismatch between load and generation, and is modeled as a stochastic process with Gaussian distribution. A historical time series ACE_O^H is reconstructed from measured data as

$$ACE_O^H(t) = ACE^H(t) + \sum AS(t), \quad \forall t : P_V^H(t) = 0 \,. \tag{4.2}$$

Where ACE^H is the measured ACE, P_V^H are recorded forced generation units outages and ΣAS denotes the sum of all activated ancillary services at the time instant t. ACE_O represents open-loop ACE in undisturbed conditions only. Then the statistical parameters of ACE_O are evaluated from ACE_O^H. A convolution between the probability density functions of ACE_O and P_V results in probability density function of the open-loop ACE, ACE_{OV} (Fig. 4.2) which shows the performance of the control area in terms of how frequently a particular magnitude of the ACE appears in relation with the total number of observations. As shown, the positive part of the function is modulated by the forced generation unit outages.

The component ACE_O can further be decomposed into a "slow component" ACE_{O_slow}, which represents "low-frequency" content with the quasi-period of 10–30 minutes corresponding to trend changes in ACE_O, and a "fast component" ACE_{O_fast}, which represents a "high-frequency" noise with the quasi-period of several minutes caused by common fluctuations in the system,

$$ACE_O = ACE_{O\_slow} + ACE_{O\_fast} \,. \tag{4.3}$$

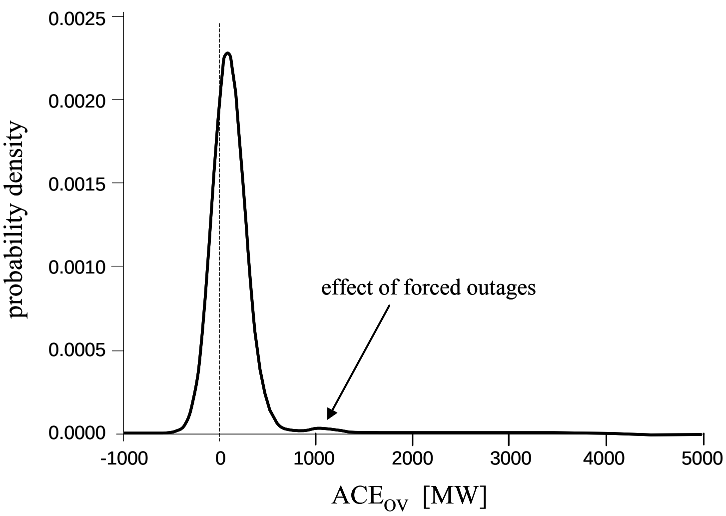

Fig. 4.2 Probability density function of ACE_{OV}

This decomposition will be used later in determination of AS needs because each of the components is compensated by a different type of AS. ACE_{O_fast} is calculated from ACE_O^H as a moving hour average and the remaining "noise" represents ACE_{O_slow}. The open-loop area control error ACE_{OV} is finally a sum of slow and fast variations of ACE_O plus forced generator outages

$$ACE_{OV} = ACE_{O\_slow} + ACE_{O\_fast} + P_V \,. \tag{4.4}$$

More details on the stochastic model of ACE can be found in [17].

4.2. Minimal Needs of AS

The AS categories considered throughout the chapter are described in Tab. 2. Analytical computations of the minimal AS needs are based on the stochastic characteristics of ACE and its components as it was determined in Step #1. Regarding the fact that some of the AS are mutually substitutable, i.e. slower-response services such as the tertiary control can be substituted by faster-response services such as the secondary control, the needs of the AS reserves are expressed in the form of the inequalities (4.5) – (4.8) rather than exact recommended values for each AS category:

$$RZSR \geq RZSR_{\min} \,, \tag{4.5}$$

$$RZSR + RZTR^{+} \geq RZSR_{\min} + RZTR^{+}_{\min} \,, \tag{4.6}$$

$$RZSR + RZQS + RZTR^{+} \geq RZ^{+}_{\Sigma\min} \,, \tag{4.7}$$

$$RZSR + RZTR^{-} \geq \max\left(RZ^{-}_{\Sigma\min}, RZSR_{\min} + RZTR^{-}_{\min}\right) \tag{4.8}$$

where $RZ^{+}_{\Sigma\min} \geq 0$, $RZ^{-}_{\Sigma\min} \geq 0$ are total minimal volumes of positive and negative reserves, $RZSR_{\min} \geq 0$, $RZTR^{+}_{\min} \geq 0$ and $RZTR^{-}_{\min} \geq 0$ are minimal required volumes of the secondary, tertiary positive and tertiary negative reserves, respectively. In addition, equation (4.9) represents a UCTE N-1 criterion

$$RZSR + RZQS \geq C_{N-1} \,, \tag{4.9}$$

where $C_{N\text{-}1}$ is the installed power of the largest generator within the control area.

As the energy of the quick-start reserve is limited and due to its quality in terms of a fast response after activation, it should be preserved for future use as much as possible. Thus it is recommended to replace this fast service by a slower one whenever possible and plan the same amount of reserve for such a slower service. This reasoning is expressed by equation (4.10).

$$RZN_{>30} = RZQS \quad . \tag{4.10}$$

Fig. 4.3 illustrates how the total minimal volumes $RZ^{+}_{\Sigma\min} \geq 0$ and $RZ^{-}_{\Sigma\min} \geq 0$ are determined from the cumulative distribution function of ACE_{OV}. According to the reliability standards, the absolute value of the closed-loop ACE is allowed to exceed the threshold 100 MW in $rACE_1$ % of cases. If this is split symmetrically to positive and negative values, ACE_{OV} higher than 100 MW should be compensated by the control reserves except for $rACE_1/2$ % of cases. Hence, we need at least $RZ^{+}_{\Sigma\min} \geq 0$ and $RZ^{-}_{\Sigma\min} \geq 0$ reserves to satisfy the standards of reliability derived from area satisfactory performance in the past.

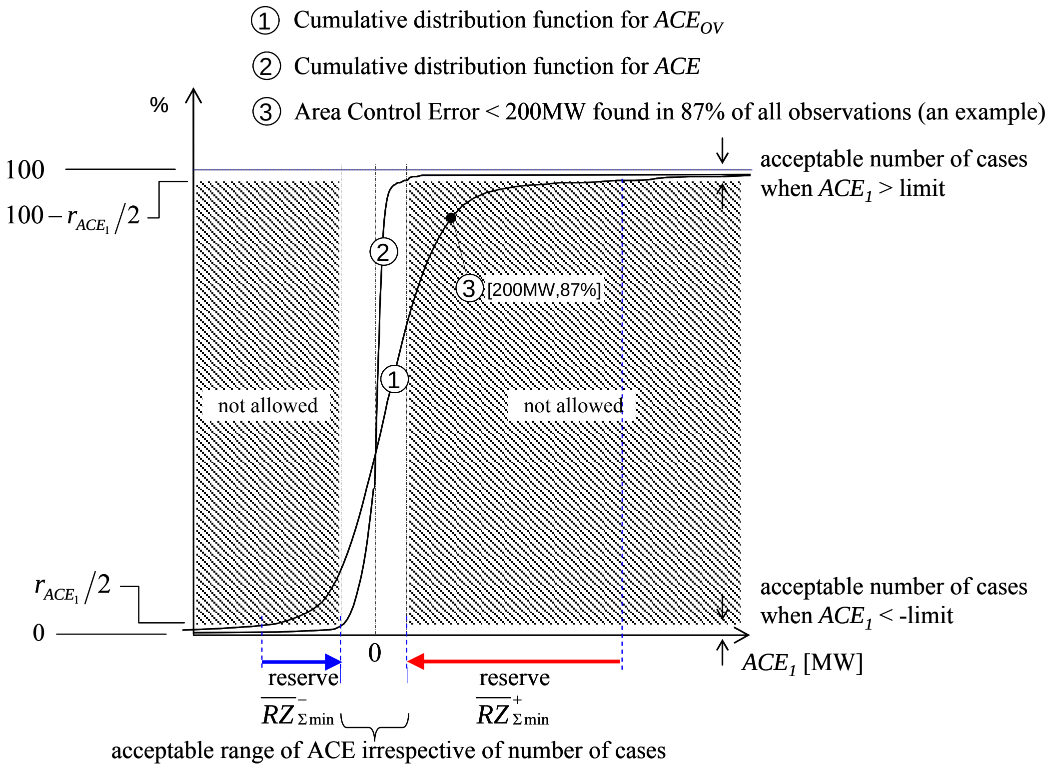

Fig. 4.3 Cumulative distribution function of the open-loop ACE and its use

The secondary reserve $RZSR_{\min}$ should compensate for the fast variations of the open-loop ACE and the tertiary reserve $RZTR^{+}_{\min}$, $RZTR^{-}_{\min}$ should compensate for the slow ACE variations. The minimal needs of these services are determined similarly to the total needs but with utilizing cumulative distribution functions of ACE_{OV_slow} and ACE_{OV_fast}.

The values of the minimal AS requirements are in the form of time series, which reflects the fact that the behavior of ACE also varies; typically, it is more uncertain in “transitions periods” with changeable weather and temperature, such as in spring or fall.

5. Control Area Simulation

Simulated ACE_{ov} and ACE with automatic activation of secondary reserve and manual activation of tertiary reserve, quick-start, standby reserve, emergency assistance from abroad and balancing energy from abroad is shown in Fig. 5.1. The simulation shows two days record with large power deviation originated from an outage of a 1000MW generator. Area control error not compensated by the TSO, ACE_{ov}, is the curve with the highest magnitude. The producer compensates the unintended power deviation by activating its own power reserves. As a result ACE_{ov} tends to be drawn towards zero but the self-regulating action is not sufficient and a significant power deviation remains for about 12 hours which is unacceptable.

The situation improves when the TSO activates its reserves. Secondary controller responds to the sudden increase in ACE almost immediately (red). As the secondary power reserve available at that time is about 400MW, it is not possible to cover the massive outage by this reserve and other services must be called up to assist. The TSO's operator activates quick-start reserve (cyan) and tertiary reserve (magenta) at the same time. Pumped storage quick-start must be saved as its capacity is limited so the operator tends to replace it as soon as possible by the services with longer response time, stand-by reserve (yellow), and/or tries to acquire services that are not guaranteed as the emergency assistance from the adjacent area (green). As a result, ACE (black) is minimized and the massive outage is well compensated via temporary combination of ancillary services or rather their activation. The role of the TSO's manual intervention is also to assure that the capacity of the secondary reserve is restored as quickly as possible so it can play its role as a an automatic feedback controller driving the output of the controller away from the limits, power reserve purchased by the TSO in advance.

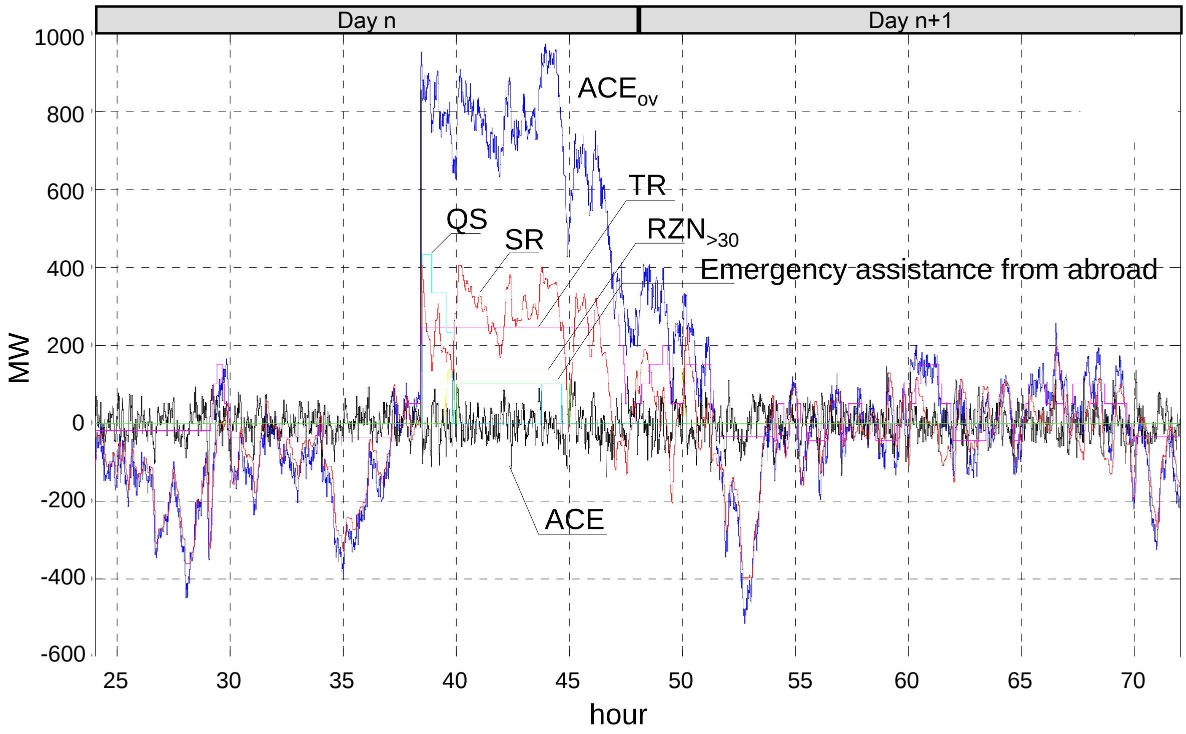

Fig. 5.1 Activation of ancillary services for area power balancing

6. RELATED TOPICS

6.1. Generation from Renewable Resources

Energy sources are under the process of permanent restructuring. Large-scale renewable resource installations like wind power, which is the world's fastest growing energy technology, represents a new challenge to the power system. The fluctuating nature of wind power affects power system reliability deviating the planned power generation which would lead to power balancing problems. Several detailed technical investigations of grid ancillary service impacts of wind power plants have recently been performed [9]. Although the approaches vary, three utility time frames appear to be most at issue: regulation, load following and unit commitment. This article describes and compares the analytic frameworks from recent analysis and discusses the implications and cost estimates of wind integration. The findings of these studies indicate that relatively large-scale wind generation will have an impact on power system operation and costs, but these impacts and costs are relatively low at penetration rates that are expected over the next several years.

6.2. Transmission Congestion Management

Grid management has become notably more complex over the past decades. The level of grid usage is increasing markedly in every region. Consistently high utilization of critical assets in a network often means that those assets have become bottlenecks limiting the use of the network and its ability to serve demands at every level consistently and reliably. These points on the grid create transmission constraints. In some cases they create congestion by limiting buyers' ability to secure energy from the most economical source, necessitating purchase from closer, more costly generators. In other cases, transmission constraints can cause a reliability problem when customer demands exceed transmission system delivery capabilities plus local generation.

With increasing power flows over a grid with rapidly changing electrical topologies, the local utility was no longer able to see and manage every factor affecting the flows upon its share of the transmission grid. The scope of grid monitoring and control that worked effectively in the days of high capacity margins and limited inter-utility flows were no longer sufficient. Higher grid usage was causing greater reliability challenges, policy-makers and utilities determined that increasing the size of grid oversight and control organizations was the only effective way to deal with these challenges.

The problem is of a great importance in countries/areas where, besides energy and ancillary services, transmission is a commodity in deregulated market with electricity and/or where the transmission capacities are almost/temporarily saturated as for those demanded power flows transmission systems were not designed.

The problems of ancillary services planning and real-time balancing power reserve activation discussed in the chapter do not address one important issue which is the limited capacity of the transmission lines. It may happen that the called-up ancillary service will overload a particular transmission line when there is scheduled energy exchange transported. As the approach described so far models the control area as a pool, it does not allow including control area network topology into the consideration. Other approaches have to be applied

In a restructured power system, the transmission network is the key mechanism for generators to compete in supplying large users and distribution companies. The lessons learned by ERCOT (Texas ISO) in flow-based zonal redispatch to relieve transmission congestion is discussed in [10].

6.3. Further Reading

The electric power industry has undergone dramatic changes in many countries in recent years. Recent de-regulation has transformed it from a technology-driven industry into one driven by public policy requirements and the open-access market. Now, just as the utility companies must change to ensure their survival, engineers and other professionals in the industry must acquire new skills, adopt new attitudes, and accommodate other disciplines. The book by

Denny and Dismukes [11], provides the engineers a broad overview of most of the topics that one needs to go through in order to understand and meet the challenges of the new competitive environment. Integrating the business and technical aspects of the restructured power industry, it explains how new methods for power systems operations and energy marketing relate to public policy, regulation, economics, and engineering science. The authors examine the technologies and techniques currently in use and lay the groundwork for the coming era of unbundling, open access, power marketing, self-generation, and regional transmission operations.

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APPENDIX

Answering the following questions will prove that the course participant managed to understand the basic principles and methods associated with power balancing in large electrical grids.

Q1 – Define Control Area of a large interconnection (synchronously connected electrical grids)

Q2 – Define Area Control Error (ACE), explain the role of the frequency bias (frequency bias obligation) and K-factor entering ACE.

Q3 – Define inadvertent interchange for a control area.

Q4 – Explain the role of power-frequency characteristic in automatic power balancing control scheme.

Q5 – Explain the difference between isochronous and droop control mode of a generator

Q6 – Describe frequency control mechanism (primary regulation) in an electrical grid.

Q7 – Describe power and frequency control mechanism (secondary regulation) in an electrical grid and explain how Automatic Generation Control (AGC) works.

Q8 – What is the role of tertiary regulation and tertiary control reserve?

Q9 – What are Ancillary Services (AS), who provides AS and how they are used in real-time power balancing.

Q10 – Define at least one performance standard used by Czech Transmission System Operator and explain the difference between performance standards defined for North America and those used in the Czech Republic.

Q11 – Explain the idea of the method applied to determine the active power reserve needed to satisfy one performance standard defined for Czech Republic.

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