Electric Power Systems Research 114 (2014) 10–20

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Load–frequency control management in island operation

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ARTICLE INFO

Article history:
Received 1 July 2013
Received in revised form 12 March 2014
Accepted 30 March 2014
Available online 19 April 2014

Keywords:
Island operation
Load frequency control (LFC)
Primary frequency control
Speed control
Load control

ABSTRACT

This paper analyzes particular cases of active power and frequency control strategies in island operation when a part of the system is electrically separated from the main interconnected system. This operation condition occurs rarely on a transmission system level; however, the control systems on all levels should be adjusted accordingly and transmission system operators should have a plan prepared to manage such an extraordinary situation. A number of possibilities for the cooperation of turbine control modes and supervisory control of frequency and active power are investigated and evaluated in the paper. A new mode for LFC suitable for island operation is proposed and tested as well. All of the examined possibilities are simulated by a dynamic power system model. The results prove correctness of the proposed solution for operating turbine control in a decentralised way in the island operation. Following the successful transition to island operation, the new LFC mode can be used for centralised automatic frequency control during the island resynchronisation phase.

1. Introduction

According to the prepared European network code [1] island operation is defined as an independent operation of the whole or a part of the network that is isolated after its disconnection from the interconnected system. The isolated part of the network has to contain at least one generator with a frequency and voltage control system. These non-standard power system operation conditions (usually emergency states – resynchronisation or restoration), contrary to normal operating conditions, require non-standard frequency control strategies.

Implementation of higher level control strategies in island operation is investigated in [2] but there is not detailed analysis of turbine control modes.

This paper analyzes various load–frequency control management modes in island operation and it compares various control possibilities for the steam turbine that is remotely controlled by LFC. It explains the difference between the centralised concept of classic LFC and the decentralised concept of conventional speed control. The new idea of combining these two concepts is presented and the feasibility and functionality of this idea is proved on case studies, using dynamic model.

Use of simulation tools (long-term stability programmes) for the study of power system dynamic behaviour in island operation is discussed in [3]; although this lacks details of cooperation between LFC and turbine control. Various turbine control modes in coordination with LFC are described in [4], but very simple generic thermal governor/turbine model (see [5]) is used without a boiler model.

The dynamic model that is presented in this paper is available for the off-line dynamic calculation of power system (as a network simulator) and also for the online simulation in the framework of a dispatcher training simulator.

The paper is organised as follows. Section 2 presents the system disturbance on 4th November 2006 and its impact on the Operation Handbook update (Policy 5: Emergency Operations). The dynamic behaviour of the Czech control area during the disturbance and a decentralised concept of the speed control in island operation are presented as well. Section 3 introduces an overview of power system frequency control. Special attention is paid to the steam turbine control implemented on power plants in the Czech Republic. The dynamic behaviour of various types of LFC and turbine control modes during island operation is demonstrated on four case studies in Section 4. Section 5 concludes our findings.

2. Experience from the disturbance on 4th November 2006

A large-scale island operation is a very rare event, but it may occur. The last such Europe-wide power system incident happened on 4th November 2006. The former UCTE grid split into three

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http://dx.doi.org/10.1016/j.epsr.2014.03.030

separate areas after the tripping of several high-voltage lines due to a cascade effect. There were significant power imbalances in each area (West, North-east and South-east).

The final report [6] states that the resynchronisation process was completed in a fully decentralised manner within 40 min after the splitting (in some cases without knowing the exact conditions in the interconnected system). On the other hand, only this decentralised approach allowed achieving the reconnection in such a short time. However, this report also recommends that different load–frequency management modes should be analysed thoroughly and their application should be predefined. The UCTE should propose the principles and define the strategies for various modes of frequency control with a special attention paid to the pure frequency mode for LFC.

These proposals are implemented in the ENTSO-E regional group continental European Operation Handbook, Policy 5: Emergency Operations [7]. This Policy defines the role of a frequency leader who is in charge of frequency management coordination and who coordinates the activation of the generation reserve within the affected area, together with the transmission system operators (TSOs) in their area, in order to recover and maintain the frequency in this disturbed area of near to 50 Hz, with a maximum tolerance of ±200 mHz. The frequency leader should be chosen within each synchronous area after a severe disturbance with a frequency deviation higher than the permissible value of ±200 mHz or in the case of system split. A TSO with the highest *K*-factor[1] will be appointed as the frequency leader. According to the Policy 5 standard, the frequency leader's LFC is switched to a frequency control mode and the other load–frequency secondary controllers remain in a "frozen" control state (without any change of set point for controlled units). This means that the frequency leader's regulation units are remotely controlled by the LFC in frequency control mode.

On the other hand, the older UCTE operational handbook in Policy 1: Load–Frequency Control and Performance ([8] from 2004) recommended that under emergency conditions and if applicable the operating mode of (thermal) generating units should/may be changed from load control or pressure control to speed control. A very fast rate of change is enabled within the whole operating range, yet it is very uneconomical. This solution was implemented in both the Czech Republic and the Slovak Republic as one condition for connection of the CENTREL countries to the UCTE in 1995. Fig. 1 shows a copy of a recommended response of thermal units to frequency deviations prepared by a former electricity utility Bayernwerk AG in 1994. There are four examples (marked by numbers 1–4) of thermal unit operation within normal frequency range 49.8 – 50.2 Hz and outside this range in a so-called 'disturbed operation'.

Units are operated in the load control ($P_{Gen} = P_{Desired}$) or with activated primary frequency control ($P_{Gen} = P_{Desired} + k_{COR}\Delta f$) in the normal operation with a range $P_{Min} - P_{Max}$. In the disturbed operation the units are switched over to an emergency speed control (a speed droop $1/k_{Speed}$ is usually 5%[2]) with a range $P_{MinIsland} - P_{Max}$ and boiler output is increased to P_{Max}. Minimal power $P_{MinIsland}$ should be lower than P_{Min} for normal operation and it is near to the home consumption P_{Aux}. If the frequency exceeds 53 Hz or it falls under 47 Hz, the coal-fired units are disconnected from the grid and they feed only its auxiliary load.

The first line represents a unit operated at full power P_{Max}. The second line represents a unit operated in the primary control with

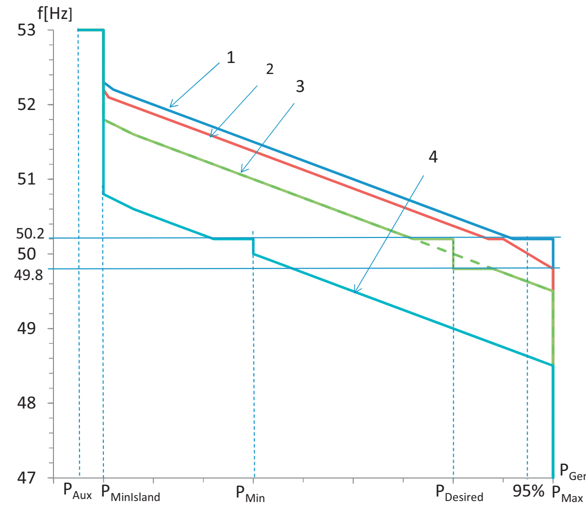

Fig. 1. Control of conventional thermal power plants – recommendation of BAG.

a speed droop $1/k_{COR}$ (usually 8% for a primary control reserve 5%). The third line represents an unloaded unit (dashed line is for primary control with a speed droop 5%). The fourth line represents a unit operated in a primary control with minimal power P_{Min}.

This solution proved its efficiency during a system-wide incident on 4th November 2006. The Czech Republic was part of the North-east island, where the active power surplus was more than 10,000 MW and instantaneous frequency reached nearly 51.4 Hz (see Fig. 2).

Due to the immediate power decrease in this island, the frequency was stabilised at 50.3 Hz within the first 30 s. The Czech Republic participated with a power decrease of 950 MW – the largest portion of power decrease in the island (not taking into account the switching off of the windmills in the eastern Germany and Austria). As a result of switch over from power to speed control, the *K*-factor of the Czech Republic control area increased more than four times from the normal value 730 MW/Hz (for primary frequency control) to approximately 3300 MW/Hz (in emergency speed control). This measure contributed significantly to power surplus regulation in the North-east island.

The concept of emergency speed control as a decentralised solution of the frequency management in island operation is an alternative to the centralised LFC control (switched to frequency control mode) and it should be taken into account in the next operational handbook revision.

Switching over from power to speed control is implemented in all conventional units (not only steam but also in hydro and gas turbines) connected into transmission system (more than 10 GW of installed power) and on the larger units connected into the distribution system in the Czech Republic. New installed renewable energy sources (RES – especially photovoltaic sources and wind turbines) shall comply with the prepared ENTSO-E Network Code for Requirements for Grid Connection Applicable to all Generators. They shall be capable of decreasing generated power with a droop of 5% when the frequency exceeds 50.2 Hz threshold according to the red dashed line in Fig. 3. A reset plan is under preparation for older RES installation. This plan emulates continuous power decreasing by disconnection of RES groups in several steps; one suggestion is depicted in Fig. 3.

3. Power system frequency control overview

Power system control is hierarchical in nature and represents a very complex system. This complex system is usually divided

[1] *K*-factor in MW/Hz corresponds mainly to incremental generation power change during incremental frequency deviation.

[2] The speed control gain k_{Speed} may be different from the frequency correction gain k_{COR} in the load control; this gain determines the slope of the turbine static characteristic (dependence of the turbine output the frequency deviation).