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Frequency Containment Reserves Dimensioning and Target Performance in the European Power System

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***Abstract*—This paper presents the methodology and results of a risk assessment to match the frequency containment dimensioning and resulting security performance by analyzing the relationship between the available amount of frequency-response reserves and the frequency quality performance in the European power system. The proposed dimensioning technique is simulated applying Monte Carlo simulations to measurements from the European power system. The results show that as the risk of running out of frequency containment reserves due to market induced load-generation imbalances increases, the amount of containment reserves must regularly be validated and eventually adjusted or the system will face a measurable decrease in reliability.**

***Index Terms*—Dimensioning, ENTSO-E, European power system, frequency-response reserves.**

I. Introduction

The successful operation of interconnected power systems requires real-time balancing electricity generation and consumption. Therefore, frequency control represents an important part of ancillary services and is crucial for the security of supply [1], [2]. The basic European frequency control concept comprises three processes for which the transmission system operators bear responsibility: frequency containment, frequency restoration, and reserve replacement [3]. Based on the nomenclature used in Continental Europe the corresponding control types are primary, secondary and tertiary control [4]–[6].

Frequency containment is a joint responsibility distributed among all transmission system operators in a synchronous area. Its focus is operational reliability achieved by stabilizing the frequency in the time-frame of seconds independent of the imbalance's geographical location. As its control structure is proportional, a steady-state error is unavoidable. The respective reserves are referred to as Frequency Containment Reserves (FCR). Frequency Restoration Reserves (FRR) and Replacement Reserves (RR) are a local responsibility of each transmission system operator for the imbalance in its control area where a decentralized load-frequency control structure is employed. FRR activation is to recover the system's frequency in the time frame defined within the respective synchronous area. RR refer to manual reserves used to free up FRR after the imbalance has been compensated and the system has settled to steady-state.

Currently, in most electrical systems the dimensioning of reserves, especially FCR, is done using deterministic methodologies e.g. the N-1 or N-2 criterion [6]. For FRR and RR dimensioning probabilistic methods are more common and intensively discussed in respect to the increasing penetration of variable renewable generation [7]–[9]. However, these methods focus on single control areas and not on a whole synchronous area, i.e. the resulting frequency quality performance.

For the FCR dimensioning in Continental Europe a N-2 criterion has been introduced in the late 1990s [10], [11]. It was assumed that imbalances occur equally due to changes in demand and tripping of generation. The risk between two consecutive trips was not taken into account and it was assumed that the frequency would be at its nominal value before an incident occurs. However, due to the implementation of energy markets and introduction of large-scale renewable generation, these assumptions may lead to insufficient FCR provision. To our knowledge no studies with a systematic assessment have been reported in the literature so far to evaluate the validity and performance of this dimensioning criterion.

Our contribution in this paper is twofold: To quantifying the needed amount of FCR and outlining the relationship between frequency quality and security of supply applying probabilistic methodologies. We focus on the Continental European power system and extend our investigation to the Nordic power system for comparison and to illustrate the universal applicability of the proposed method to systems with different control structures. We utilize time sequential Monte Carlo simulations, which are a common approach for reliability modeling [12].

This paper is organized as follows. Section II presents the methodology for dimensioning the reference incident. Section III provides the simulation results. It includes examples of two synchronous areas based on actual measurements and historical data. Section IV and Section V analyze the implications on system security. Finally, Section VI is devoted to conclusions and perspectives.

II. The Reference Incident in ENTSO-E Power Systems

Synchronous areas whose corresponding transmission system operators are members of ENTSO-E have defined the reference incident to be the maximum expected instantaneous power deviation between generation and demand in the synchronous area. The dynamic behavior for which the system has been designed takes into account this reference incident.

The synchronous area reserves response must be designed in such a way that after the occurrence of an imbalance smaller or equal to the reference incident the system returns to a stable state without the need for load or production shedding. Historically, it has been considered that the largest possible imbalance is originated by a generation loss. In order to fulfil the N-1 criterion the reference incident is sized taking into account at least the loss of the system component causing the largest imbalance, e.g. generation unit, loss of a line section, bus bar, or HVDC interconnector. In Continental Europe (former UCTE) a deterministic approach has been chosen, but using an N-2 criterion to cover the risk of a second loss in a 15 minute time window and establishing the reference incident in $3000\,MW$ to account for the possible simultaneous failure of two $1500\,MW$ nuclear units in the same power station ("double block failure") [10], [11]. An alternative method for sizing the reference incident is by means of probabilistic method to estimate a reasonable size of reference incident to assure that incidents leading to an even larger imbalance are extremely rare, but within some boundaries.

This off-line analysis has been carried out for Continental Europe making use of historical data to determine which is the largest generation/in-feed loss expected in a certain number of years. This alternative methodology consists on analyzing a typical peak generation scenario using time sequential Monte Carlo simulations with a step size of one minute in which a probability of tripping is assigned to each generator. It is assumed that the largest imbalance occurs due to generation tripping as imbalances due to loss of supply are much smaller assuming that the system is in a normal state. Significant fluctuations of variable renewable generation occur on a wider time frame and are not needed to be taken into account for this analysis.

III. Basic Scenario for the Continental European and the Nordic power system

For the probabilistic analysis, a generation scenario for a peak moment is modeled with all units larger than $200\,MW$. Table I shows the average number of trips per year for each technology in Continental Europe. The probability of common mode failures is not reflected in the table for confidentiality reasons.

Type of generating unit	Number of failures per year	Percentage loss of power
CCGT	9.47	100 %
Gas	4.27	100 %
Gas and Oil	3.30	100 %
Hard coal	7.50	100 %
Hydro	0.52	100 %
Lignite	6.21	100 %
Nuclear	1.68	100 %

TABLE I
Average forced failure rates for Continental Europe.

It is assumed that the units are operating at full capacity in the scenario and when a unit trips it loses its full power and does not reconnect to the network within the next 30 minutes, i.e. forced unit outage. The expected number of trips per year based on historical data is used to calculate the probability P for each unit to trip in a certain minute. It is assumed that the probability of tripping of a certain unit is constant in time. Therefore, a Poisson distribution is used to determine the probability that each unit has of tripping in a certain minute using the following formula:

$$P(\lambda) = 1 - \exp\left(\frac{-\lambda}{525600}\right) \quad , \tag{1}$$

where P is the probability of tripping of the unit in a certain number of minutes and λ is the number of trips per year for the unit. The number of trips per year must be divided by the number of minutes in a year (525600 hours for a non-leap year). When a unit trips, it is assumed that the FCR recover the balance of the system in the same minute as the deployment time of FCR which is 30 seconds in Continental Europe. The effect of the self-regulation of loads is not taken into account as it is considered as an additional safety margin in the dynamic design [5]. Furthermore, within a power plant there might be some modes of common failure of more than one generating unit; the probabilities of these rare events are taken into account as well. The Monte Carlo simulation is time sequential since it is essential to model that the FCR used in one minute to counteract an imbalance in the previous minute will not be recovered, and there is a probability for another unit to fail and trip before the FCR have been replaced by the FRR. The effect of the FRR in the FCR is modeled considering that FRR deployment is equivalent to the response of a first order linear system with a time constant of 5 minutes [4].

In the case of error correction the response of a first order linear system would be:

$$y(t) = A \cdot \exp\left(\frac{-t}{\tau}\right) \quad , \tag{2}$$

with A being the initial error and τ the time constant. In the case of the Monte Carlo simulations A depends on the initial ACE of the control area that has an imbalance which is generally unknown. However, the relationship between the error at time t and the error at time $t+1$ is easy to calculate:

$$\frac{y(t+1)}{y(t)} = \frac{A \cdot \exp\left(\frac{-(t+1)}{\tau}\right)}{A \cdot \exp\left(\frac{-t}{\tau}\right)} \tag{3}$$

$$= 0.8187 \quad . \tag{4}$$

With a time constant for the FRR deployment τ of 5 minutes the relationship between the ACE of the area in which the generation trip occurred at time $t+1$ is 0.8187 of the ACE at time t if no other trip occurs in the same area assuming that this trip is the only imbalance that has occurred in the synchronous area.

In order to simulate a large enough number of minutes the Monte Carlo simulation is run for 10^8 minutes, i.e. 190 years. The probability density function of the needed FCR due to generation tripping is deducted from the number of minutes in the simulation where the needed FCR was of a certain amount. The results are shown in Figure 1.

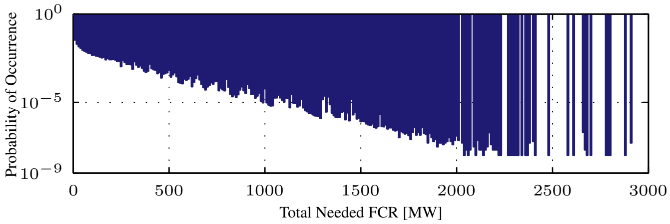

Fig. 1. Probability distribution on a logarithmic scale of the needed FCR in the Continental European power system due to generation trips.

The maximum needed FCR in the simulation was $2910\,MW$. The current reference incident defined for Continental Europe seems to be reasonable, conservative enough to assure that larger imbalances will be rare, but within reason.

It can be noted that the Monte Carlo simulation takes about 10 hours to run on an ordinary workstation computer as there are more than 850 possible generation trips that may happen in every minute. This computation time is perfectly admissible for regular off-line studies.

A similar study has also been performed for the Nordic power system (former NORDEL) although there are significant differences in the amount of available FCR and how it is restored by the FRR (at the time of this analysis the Nordic power system used solely manual FRR) [13]. A Monte Carlo simulation for a generation scenario for a peak moment is modeled with the units larger than $100\,MW$. It is assumed that the units are operating at full capacity and that when a unit trips it loses its full power and does not reconnect to the network within the next 15 minutes. The expected number of trips per year based on average historical data for each technology in Continental Europe is used as data is not available for the number of trips per year in the Nordic power system. Therefore, the probability of tripping of a certain unit is constant in time. Moreover, it is assumed that the FCR recover the balance of the system in the same minute as the deployment time of FCR and the system reaches a quasi-steady state. The effect of the FRR in the FCR is modeled considering that FRR deployment is manual and takes place between 6 and 20 minutes after the incident.

The Monte Carlo simulation for the Nordic power system is also run for 10^8 minutes. The results are shown in Figure 2. The maximum needed FCR was $2580\,MW$.

In reality, the FCR dimensioned in the Nordic power system is of $1600\,MW$, according to the simulations the Nordic power system would run out of FCR due to generation tripping 13 times in 190 years or once in 14.6 years. This risk seems reasonable for a system 8 times smaller than the Continental European power system.

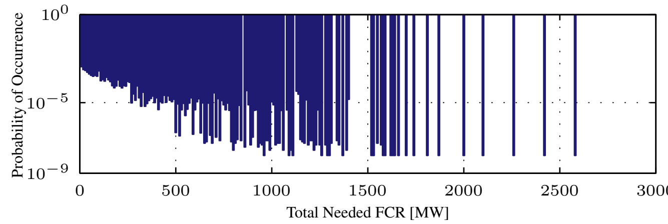

Fig. 2. Probability distribution on a logarithmic scale of the needed FCR in the Nordic power system due to generation trips.

IV. Impact on System Security in Continental Europe

An analysis of the frequency behavior of a synchronous area shows that large imbalances are not only caused by generation tripping [8], [9]. Other reasons for imbalances are load variations and forecast errors as well as changes of production in large generation units due to program changes from one settlement period to the other. The latter have become more frequent and more severe in most synchronous areas in the last years as energy markets evolve [14]. These market induced (load-generation) imbalances are compensated by FCR as well. Until FRR take over, some FCR will already be in use and not ready to counteract a generation or load trip. The larger these frequency deviations are and the more time it takes to counteract them the more probable it is that a large imbalance incident occurs simultaneously. This can lead to an event causing the frequency to surpass the established limits within the design of the system and eventually to load or production shedding. Subsequently, the number and length of the frequency deviations must be supervised and limited. For example, in the Nordic power system one of the frequency quality targets is that the frequency does not stay outside a normal operating band of $100\,mHz$ more than a given number of minutes per year. The minutes are counted as inside or outside the band by integrating the frequency value for the whole minute.

A. *Probabilistic Methodology*

In order to quantify the risk of needing more than the contracted FCR a probabilistic assessment can be performed. It will show the consequences of poor frequency quality by calculating the risk of using up all the FCR available by the combination of a frequency deviation prior to a large generation trip. Such scenario will lead to the exhaustion of the FCR and the frequency will eventually be stabilized by the activation of under frequency load shedding relays, i.e. an unwanted loss of supply to customers.

In the probability calculation it is assumed that the frequency deviations due to changes in demand or renewable generation and the market induced imbalances are independent from the generation losses due to unit trips. Both effects can be modeled by a probability density function to define the FCR needed to counteract them. The probability density function of the needed FCR due to generation trips can be calculated with the above mentioned method. The probability distribution function of the needed FCR due to market induced imbalances can be derived from the FCR deployment that is caused by a frequency deviation. It can be assumed that the FCR deployment is linear to the frequency deviation in a quasi-steady state after the dynamic effects of the imbalance have disappeared [5]. In order to discard the frequency deviations due to generation trips the 15 minutes after a generation loss larger than $1000\,MW$ have been discarded. Since the available FCR are $\pm 3000\,MW$ and the quasi-steady state frequency deviation $0.2\,Hz$ the frequency deviations are multiplied by $\mp 15000\,MW/Hz$ (negative frequency deviations lead to positive need for FCR). In order to calculate the risk of needing more FCR than available the distribution function of the total needed FCR is generated convoluting both probability distribution functions. This function is shown for the example of Continental Europe in 2010 in Figure 3.

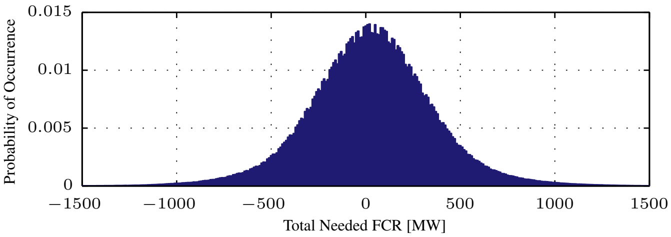

Fig. 3. Probability distribution of the total needed FCR from -1500 to $1500\,MW$ in Continental Europe.

By integrating the probability distribution of the total FCR from the available FCR to $+\infty$ the risk of needing more FCR than available can be obtained. For the year 2010 this integral equals $1.0 \cdot 10^{-7}$ or once in 19.3 years. This number shows the severity of the effect of market induced load-generation imbalances. If these did not occur the probability to run out of FCR would be less than once in 190 years.

B. Minutes outside a defined Frequency Band as Indicator for Frequency Quality

Assuming that the number of minutes outside the frequency deviation band due to generation trips remains constant in time and the probability distribution of the needed FCR due to market induced imbalances follow a certain modified t-Student function, the risk of needing more FCR than available can be generalized and calculated for a given number of minutes outside a standard frequency deviation band. This modified t-Student function is the following distribution:

$$s(t) = f\left(\frac{t}{m}\right) \cdot K \quad , \tag{5}$$

where $f(t)$ is a t-Student distribution, K is the constant that makes the integral of $s(t)$ equal to 1, and m is a multiplier related with the dispersion of the data as the regular t-Student function has a standard deviation of 1 which is not the case with actual data:

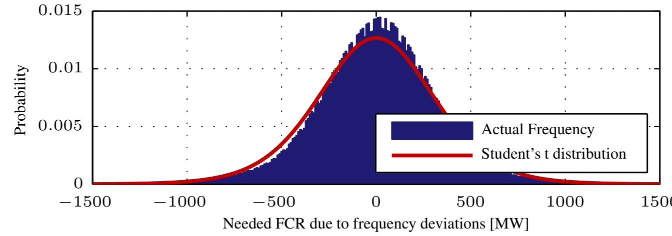

Fig. 4. Probability distribution due to the frequency deviations in 2010 not associated with sudden generation trips and the Student's t distribution to which these values were adjusted.

$$f(t) = \frac{\Gamma \cdot \left(\frac{\nu+1}{2}\right)}{\sqrt{\nu \cdot \pi} \cdot \Gamma\left(\frac{\nu}{2}\right)} \left(1 + \frac{t^2}{\nu}\right)^{-\frac{\nu+1}{2}} \quad , \tag{6}$$

where ν is the degrees of freedom of the t-Student function and Γ is the Gamma function.

The distribution fitting can be performed equaling the number of minutes outside a defined range in the real data discarding those that were caused by generation tripping and in the Student's t as shown in Figure 4: The $75\,mHz$ range is the typical frequency quality criterion in Continental Europe and the total number of minutes outside that range was 2361 out of which 132 were due to generation trips larger than $1000\,MW$ and 2229 minutes due to market induced imbalances. The probability distribution function of the needed FCR due to market induced imbalances can be fitted to a t-Student distribution with $\nu = 10$ and $m = 307$.

Assuming that the degrees of freedom of the t-Student distribution remain constant as the frequency quality varies, quantified by the number of minutes outside $75\,mHz$, it can be calculated how the risk of needing more than the available FCR increases or decreases as a function of the frequency quality by using the indicator of number of minutes per year outside the $75\,mHz$ band. It must be assumed that the number of minutes outside the $75\,mHz$ band due to generation trips remains constant. In order to find the t-Student distribution that corresponds to a certain number of minutes outside the $75\,mHz$ band the parameter m is varied. These new distributions illustrate how the risk of needing more FCR than $3000\,MW$ changes as the number of minutes outside $75\,mHz$ increases or decreases. Looking at past years, the evolution of the risk of needing more than $3000\,MW$ of FCR from the year 2002 until the year 2011 is shown in Table II.

V. Impact on System Security in the Nordic Power System

In the Nordic power system, like in the Continental European power system, the main source of frequency deviations is the market induced imbalances and not the generation trips. The described methodology has been applied to calculate the risk associated to frequency deviations due to causes other than generation trips. In this case, the self-regulation effect of loads is taken into account as it is significant in this much

Year	Number of minutes outside $\pm 75\,mHz$	Multiplier m	Risk in years between events
2002	581	240	32.5
2003	1325	274	23.5
2004	1455	282	22.5
2005	1358	279	23.1
2006	2040	299	19.2
2007	1113	269	25.3
2008	1860	294	20.2
2009	2048	299	19.2
2010	2360	307	19.3
2011	1711	290	20.9

TABLE II
EVOLUTION OF THE RISK OF NEEDING MORE THAN $3000\,MW$.

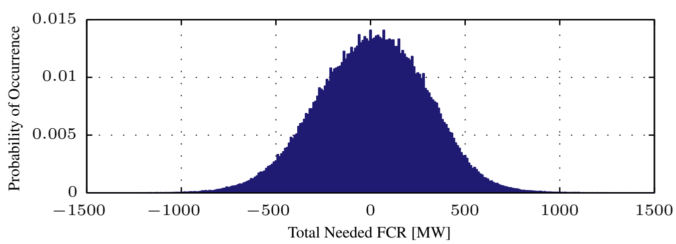

Fig. 5. Probability distribution of the total FCR from -1500 to $1500\,MW$ in the Nordic power system.

smaller system and as it is not considered as safety margin [13]. For frequency deviations of $\pm 100\,mHz$ $\mp 600\,MW$ of FCR are deployed (linear FCR deployment). This results in $\mp 6000\,MW/Hz$. However, assuming a self-regulation effect of loads of $2.5\,\%/Hz$ and a system size of $40\,GW$ there is an additional $1000\,MW/Hz$ due to this self-regulation, resulting in $\mp 7000\,MW/Hz$. As for Continental Europe the needed FCR is the sum of the needed FCR due to generation trips and market induced imbalances. The total needed FCR probability distribution function is obtained by convoluting both probability distribution functions. This function is shown for the Nordic power system in 2010 in Figure 5.

Integrating the probability distribution of the total FCR from the available FCR to $+\infty$ the risk of needing more FCR than available can be obtained. The available FCR in the Nordic power system is $1600\,MW$ plus $200\,MW$ due to the self-regulation of loads. The risk of needing more than $1800\,MW$ is $2.36 \cdot 10^{-6}$ or once in 0.82 years. This risk is considered quite high. In reality, many hydro units are running in frequency mode which often increases the available FCR. In addition, the HVDC interconnectors to Continental Europe are providing frequency-response reserves for very large frequency deviations in the Nordic power system.

VI. CONCLUSIONS

This paper presents a probabilistic analysis that can be performed in large interconnected systems around the world in order to assess the frequency-response dimensioning and the influence of frequency quality on security of supply. As it has been shown, the effect of market induced load-generation imbalances is highly significant and their influence on the behavior of the system cannot be neglected. This type of off-line analysis should be performed at least once a year for a synchronous area to monitor the evolution of the frequency quality and its risk of needing more FCR than contracted. If the detected risk is not admissible, actions should be taken to improve the frequency quality such as increasing the amount of FCR or making the necessary adjustments in the power market design to mitigate market induced load-generation imbalances.

Due to the sensitivity of this risk to the amount of minutes outside the selected frequency range an indicator or limit should be set and actions taken to assure that the security of the system is not jeopardized by market induced frequency deviations. This indicator or limit should be set choosing a desired risk and calculating a respective distribution that will set the desired risk.

The results of the outlined methodology and investigations have been used by the drafting team for the European Network Code on Load-Frequency Control and Reserves which has been submitted to the European Commission for approval and adoption mid-2014.

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