European Network of
Transmission System Operators
for Electricity

REPORT ON DETERMINISTIC FREQUENCY DEVIATIONS

Final | 16 October 2020

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List of Abbreviations

aFRR	automatic Frequency Restoration Reserve
BRP	Balance Responsible Parties
FRCE	Frequency Restoration Control Error
CE	Continental Europe
DACF	Day-ahead Congestion Forecast
DFD	Deterministic Frequency Deviation
EAS	ENTSO-E Awareness System
EFR	Enhanced Frequency Response
FCR	Frequency Containment Reserve
FFR	Firm Frequency Response
IDCF	Intraday Congestion Forecast
ISP	Imbalance Settlement Periods
LFC	Load Frequency Controller
MFR	Mandatory Frequency Response
MTU	Market Time Unit
NEMO	Nominated Electricity Market Operator
PLR	Part Loaded Response
SA	Synchronous Area
STOR	Short Term Operating Reserve
TSOs	Transmission System Operators
XBID	Cross Border Intraday Market

Executive Summary

From 9 to 11 January 2019, the Continental Europe (CE) Synchronous Area faced an extraordinary frequency and time deviation due to the convergence of the following two main events:

- The Deterministic Frequency Deviation (DFD) during the evening peak-load at the hourly schedule transition;
- A long-lasting frequency deviation (average -30 mHz) caused by a technical failure given by a frozen measurement on four tie lines between TenneT Germany and APG grids, which affected the Load Frequency Controller (LFC) of both the TenneT Germany Control Area and the Germany Control Block.

The cumulative effect of the permanent frequency deviation due to the frozen measurement, in addition to the large evening DFD, culminated on 10 January at 21:02 when the steady-state frequency in the CE system reached 49.808 Hz. This low frequency value triggered the automatic activation of the RTE Industrial Interruptible Service (decreasing the French load by 1250 MW within 5 seconds and up to 1700 MW in 30 seconds), which quickly returned the frequency to within the normal frequency range.

A Task Force was approved on 6 February 2019 by the ENTSO-E System Operations Committee (SOC) to investigate the events during 9 and 11 January 2019 and to identify the Causal Factors and mitigating actions to prevent a re-occurrence of this type of event. The Task Force consists of representatives from 15 transmission system operators (TSOs) and ENTSO-E Secretariat. The technical report published (**here**) investigating the events during 9 and 11 January 2019 has already been approved by ENTSOE System Operations Committee.

This DFD report developed by the Task Force elaborates on the general approach for mitigating and alleviating the DFDs in CE. The task force is proposing to set common DFD targets for the Synchronous Area of CE. The solutions for mitigating the DFDs can be different from TSO to TSO, depending on the technical and market preconditions, but the final objective is to commonly reduce the individual contribution of the LFC Blocks to an acceptable level of DFDs.

During December 2019 and January 2020 ENTSO-E conducted a public consultation. The results of this consultation are included in section 5 of this report. For each question, section 5 provides all public answers provided by stakeholders, a summary of the received answers from stakeholders, and a response from ENTSO-E on the answers from stakeholders. ENTSOE position on DFDs and strong determination to reduce DFDs has been presented to ACER, NRAs and European Commission at the Electricity Coordination Group (ECG) meetings during 2019 and 2020. The discussions have been well received with a commitment from the ECG to support the reduction of the DFDs.

In general, ENTSO-E supports the feedback given by the stakeholders, and this input will be used in the further development of mitigation measures by each Country in Continental Europe. The feedback from stakeholders does not alter the conclusions of the report as the choice of mitigation measures is left to the different countries or control blocks and the report does not impose any specific solution on any individual country. ENTSO-E sees a need for sufficient measures aiming at reducing root causes of DFDs (15 minutes MTU, ramping etc) which can be complemented by the measures aiming to mitigate the frequency deviations (e.g. FCR increase). The choice of mitigation measures will be decided by the individual TSOs, LFC blocks and their respective NRAs.

Proposed Solutions

Working Package 3 of the Task Force Significant Frequency Deviations' preferred solution is moving towards a 15-minute Imbalance Settlement Period (ISP) and Market Time Unit (MTU) in a stepwise manner, at the national and international level and for any or all relevant timeframes. This proposal is in line with existing or upcoming legislation (Network Codes, Guidelines and Clean Energy Package) and is described in more detail in section 4.3.1 of this report.

In addition, as permanent or intermediate measures, the following solutions can reduce the impact of the DFDs:

1. ramping imposed on generation units on a national level (section 4.3.3)
2. include a provision for ramping on load and generation schedules at the national level (section 4.3.2)
3. increase the volume of Frequency Containment Reserve (FCR) available to control the DFDs (section 4.4.1) as a temporary measure, awaiting the implementation of other solutions.

Other solutions which have been discussed and which could be investigated for particular control blocks could include:

(a) Introduction of a limit of change in net position of a market area / bidding zone between two successive market periods;
(b) Introduce Spot Power Balancing, also known as Residual Central dispatch;
(c) Use changes between ISP for BRPs as market based automatic frequency restoration reserves (aFRRs) bids;
(d) Additional Very Fast Reserves from Battery Storage;
(e) Additional aFRRs;
(f) K-factor adaptation
(g) Introduction of a Dynamic Frequency Setpoint in Control Areas / Blocks

National implementation

Given the market situation and that the production mix (shares of units with considerable ramping capabilities) may differ in different market areas of Member States within the CE Synchronous Area, the Task Force also recommends a possible hybrid solution whereby different mitigation measures are implemented at the national level, depending on the specifics of each country. The goal of the hybrid solution is to reduce the level of DFDs to an acceptable level, while supporting flexibility in terms of the selection of cost-effective measures within the local context.

ENTSO-E proposes to leave the decision on which solutions to mitigate the DFDs to be implemented in each LFC block, and at the national level to the national TSOs and regulators. The proposed solutions in this report are not-exhaustive and any other local solutions can be proposed.

Each LFC Block must set up and follow an action plan to implement the chosen solution(s). Each LFC Block will report to ENTSO-E periodically regarding the implementation of the measures.

Setting the targets

Each LFC block needs to respect the quality target as proposed in this report, Chapter 3 – acceptable DFD level of 75 mHz. Once the targets are accepted, they will be integrated into the SAFA to cover:

- The establishment of the quality targets values per LFC block;
- The measurement of the targets compliance by following instantaneous or average FRCE values;
- The mechanism by which the targets' compliance is monitored;
- The TSOs consequences for non-compliance.

Monitoring and Enforcement

ENTSO-E Regional Group Continental Europe will set up a process for monitoring the DFDs and report on a quarterly basis on all LFC Blocks' compliance level. The observed DFDs during the monitoring process are those which violate the frequency quality target, as defined in Chapter 3 of this report.

The DFD monitoring process will formally start in 2021, allowing time for all LFC Blocks to implement the selected mitigation measures.

Action Plan

The recommendations of the final report will require the implementation of at least one of the suggested solutions by 2021, with the aim of meeting the quality targets set for each LFC block of CE.

Recognising the ongoing challenges in managing the system frequency, both across the hourly schedule change and during steady state operation, it is prudent to implement a comprehensive action plan to address these challenges. The proposed solutions are to be implemented progressively with all actions completed by 2021.

Each LFC Block not yet complying with the FRCE target will be required to deliver its implementation plan to ENTSO-E regional group Continental Europe.

If no solutions are implemented by some LFC Blocks and the DFDs are still too high according to the targets established by the Task Force, ENTSO-E regional group Continental Europe could decide that these Control Blocks acquire additional FCR to assist in reducing DFDs until the necessary solutions are in place.

1 Definition of the Problem

1.1 Introduction and Approach

Given the events that occurred on 10 January 2019 and the evidence of DFDs occurring in CE since 2003, the System Operations committee and the Market Committee of ENTSO-E have decided to set up a task force to examine the circumstances giving rise to the DFDs and implement an Action Plan to definitively manage DFDs and thus avoid any further deterioration in frequency quality.

The task force is comprised of experts from System Operations and from Markets who have studied the question of DFDs extensively and are ready to achieve a common view on the proposed way forward.

This document elaborates on the general approach for the mitigation and alleviation of DFDs. The foundation of this approach is the definition of common DFD targets for the Synchronous Area and quality targets per LFC Block that form the basis for the assessment of the necessity to take mitigation and alleviation measures within the responsibility of the LFC Blocks. The chosen mitigation and alleviation measures might be different from TSO to TSO depending on the technical and market preconditions but have the aim in common of reducing the individual contribution of the LFC Blocks to an acceptable level. The reader will find an explanation for why the approach proposed cannot be a 'one-size-fits-all' proposal with the aim of unifying the approaches for the mitigation of DFDs across the Synchronous Area.

In addition, this document presents historic trends and analysis of market based DFDs. Possible mitigation measures and next steps to resolve DFDs are discussed.

This document will provide an answer to the following questions:

(1) Why is it a problem to have large DFDs at the change of the hour in the morning and in the evening?
(2) Where are the DFDs coming from?
(3) What does ENTSO-E consider to be acceptable as frequency deviations from a System Security point of view for the Synchronous grid of CE?
(4) Which solutions can be envisaged to reduce the size of the DFDs?
(5) Which set of solutions is practically implementable and will solve the deviations?
(6) What is the action plan to ensure these solutions are implemented in reality?

1.2 Deterministic Frequency Deviation Historic Trends Analysis

The quality of frequency in the CE Synchronous Area has decreased during the last few years. More precisely, continuous measurements of the frequency show that the value is deviating more often, and for longer periods from the average value of 50 Hertz. Figures 1 and 2 show, over the last 5 years, and per month, the number of frequency deviations which were higher than 75 mHz and higher than 100 mHz. These graphs clearly show that, especially the very large DFDs above 100 mHz, have recently increased considerably in number, and the 75 mHz variations have already been high in number for some time.

Note that these graphs show the variation 'peak to peak' from maximal to minimal frequency or minimal to maximal frequency during the DFD. So, for instance, a DFD which has a variation from 50.04 to 49.94 Hz will be reported in these graphs as a variation of 100 mHz (50.04 – 49.94).

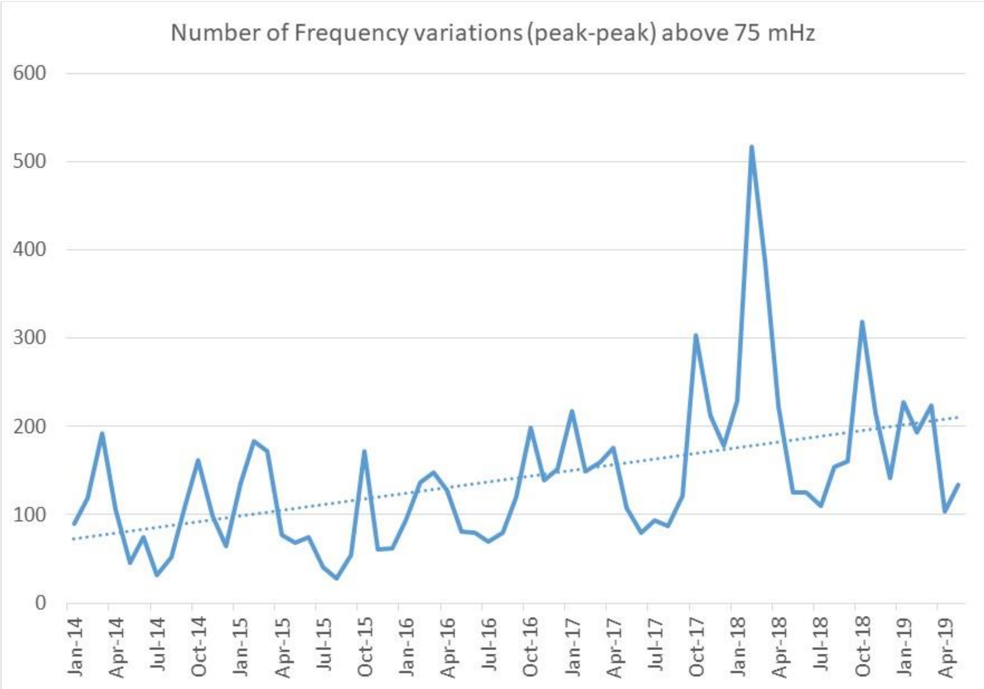


Fig. 1 – Number of +/- 75 mHz criteria violations

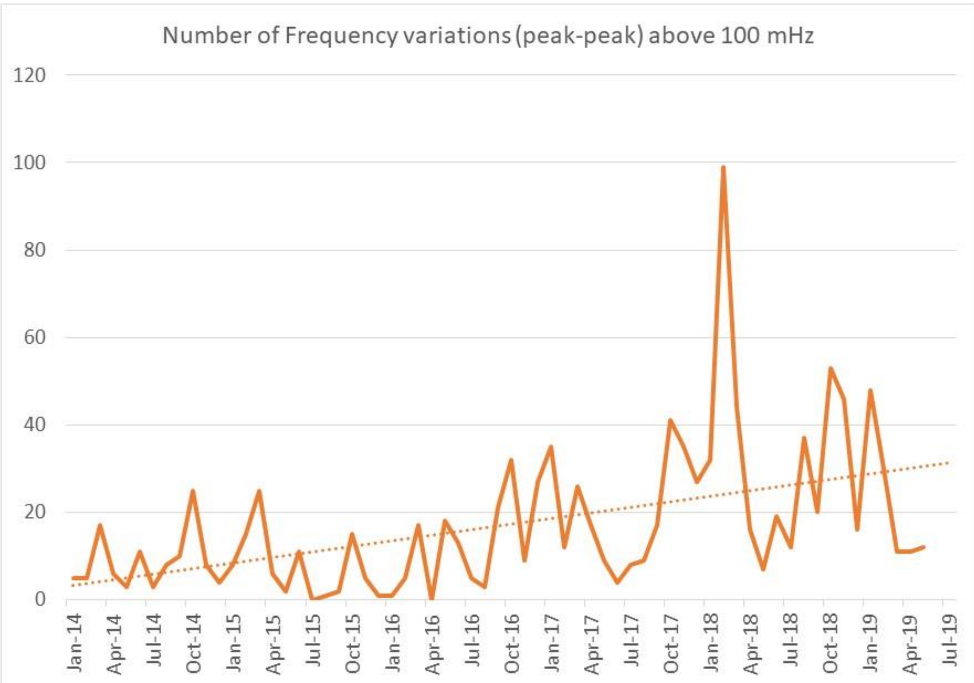


Fig. 2 – Number of +/- 100 mHz criteria violations

Figure 3 shows over the last 18 years, and per month, the number and duration of periods when frequency deviation was greater than 75 mHz. It can be clearly seen that the number and intensity of deviations increases during the winter period.

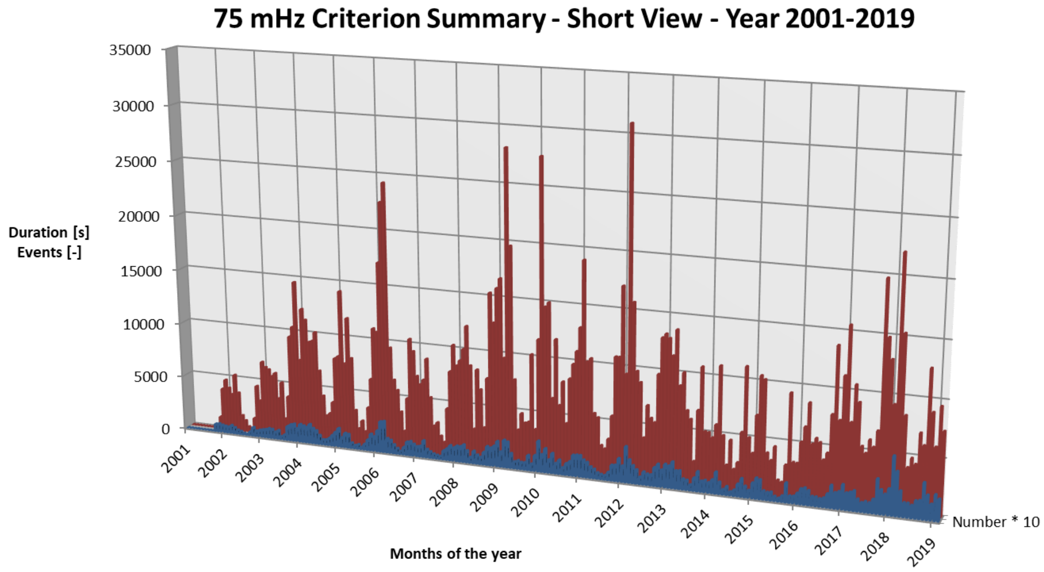


Fig. 3 – Number and duration of +/- 75 mHz criteria violation

A very high percentage of the frequency deviations are caused by DFDs. Figures 4 to 5 illustrate the total number and period of duration in the frequency deviations higher than 75 mHz and 100 mHz within the last two years and the participation of frequency deviations caused by DFDs in those values. Approximately 85% of the deviations are deterministic with respect to the 75 mHz limit and more than 90% with respect to the 100 mHz limit. In addition, the size of the absolute frequency deviations has been permanently increasing during the last few years. For instance, on 24 January 2019 at 06:00, the CE Synchronous system experienced its largest positive DFD of +173 mHz.

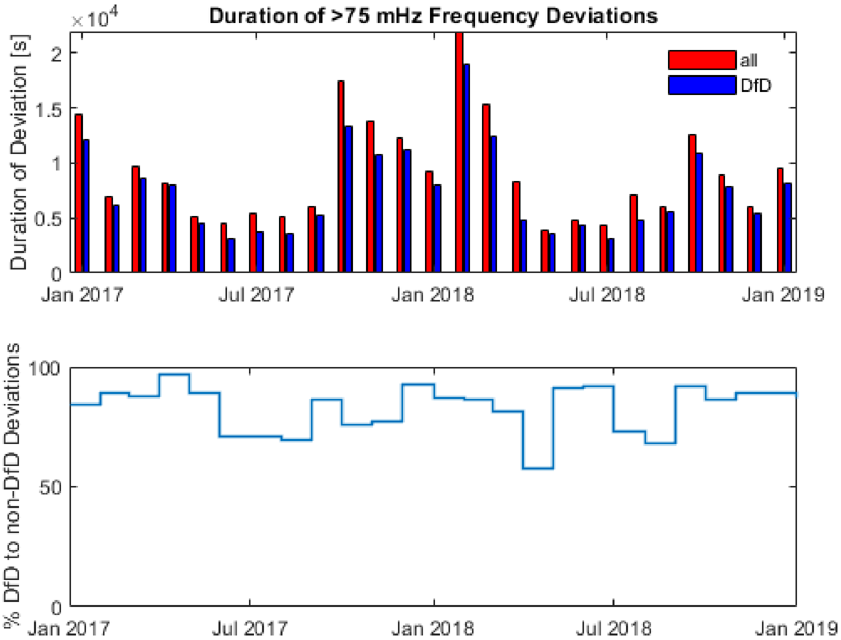


Fig. 4 – Duration of DFDs and % of DFD compared to all deviations in the last 2 years (>75 mHz)

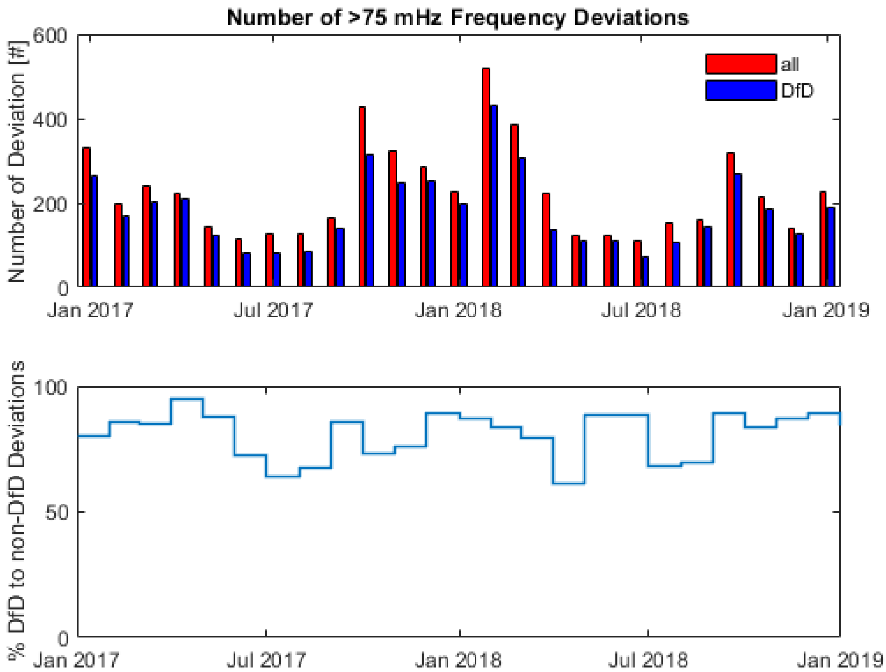
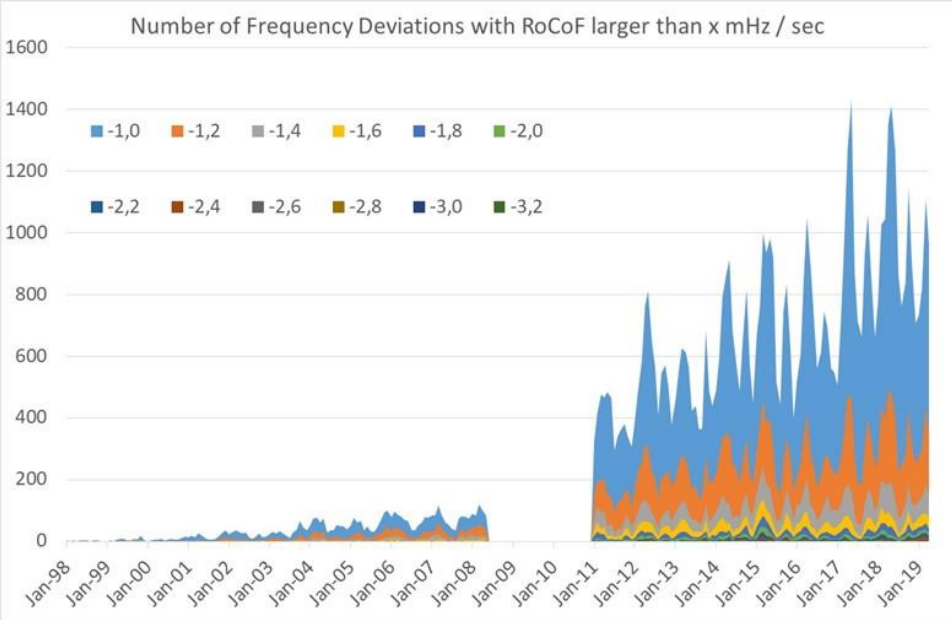


Fig. 5 – Number of DFDs and % of DFD compared to all deviations in the last 2 years (>75 mHz)

Analysis has also been carried out on the rate of change of frequency (RoCoF) during the DFD. It has been observed from regular sampling of the DFD over the past few years that the speed at which the frequency changes is increasing from values which were always smaller than 1.5 mHz per second about 10 years ago to values which now reach regularly a value of 3 mHz per second, and sometimes reach critical values of 5 mHz per second. This RoCoF is already the same as during forced unit outages, with a size of approx. 600–800 MW. This is getting close to the maximum speed at which FCR is expected to react (and for which it was designed). Further increases in the coming years could result in more serious DFDs and lower frequency values

The following statistics involve the largest negative frequency deviations over a 30 second period during a DFD. The 30 seconds mark is important, as this is equal to the activation time of the FCR. Fig 6a shows the evolution of the RoCoF of the observed DFDs since 1998. Where ten years ago a RoCoF of 2 mHz / sec did not exist, we currently regularly face RoCoF of above 3 mHz / sec.



The higher levels of RoCoF above 2.2 mHz / sec are magnified in the graph below, as these are most relevant to observe the amplitude of the problem.

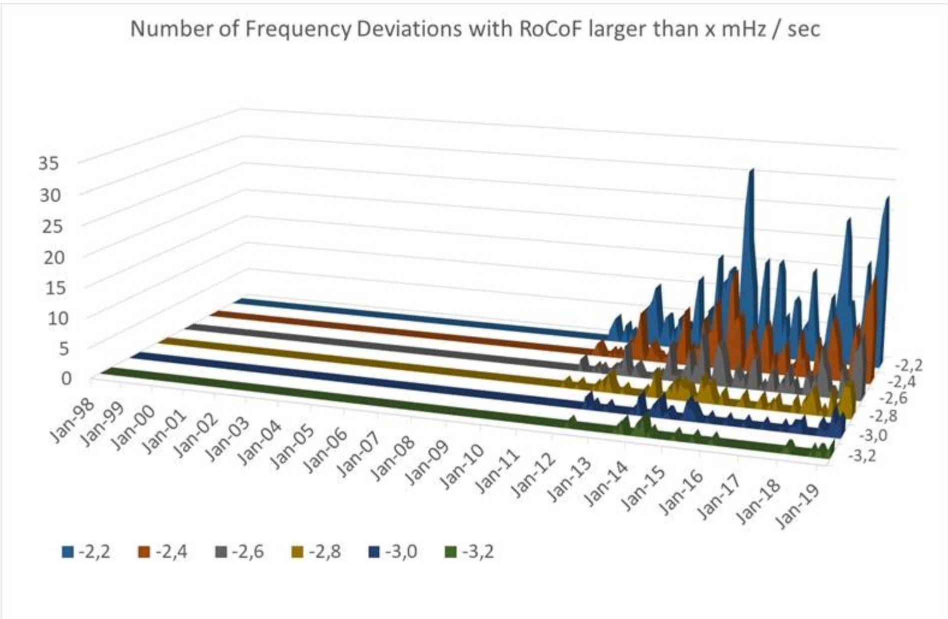


Fig. 6 a&b – Observed RoCoF of DFD in mHz / sec per month from 1998 until today

The table below shows the highest frequency variations observed in January 2019 over 30 seconds, which is the time of activation of FCR. The highest variations were almost 100 mHz, which is almost half of the speed at which FCR currently reacts. It is worth noting in the table below that most of the fastest variations on DFDs occur at 22:00 each day, so it is worth investigating the possible root causes for these fast variations of frequency at 22:00.

Date	Timestamp	mHz change over last 30 sec
07/01/2019	22:00:35	-98.30
13/01/2019	22:00:35	-92.32
26/01/2019	22:00:35	-91.28
16/01/2019	22:00:30	-89.33
14/01/2019	22:00:35	-83.38
12/01/2019	22:00:35	-79.53
22/01/2019	22:00:35	-79.05
28/01/2019	22:00:35	-76.47
02/01/2019	21:00:50	-75.38
27/01/2019	22:00:35	-74.98
30/01/2019	23:00:50	-73.42
08/01/2019	22:00:35	-71.80
01/01/2019	22:00:40	-71.73
31/01/2019	22:00:30	-71.12
29/01/2019	19:01:00	-69.82
04/01/2019	22:00:40	-69.18
15/01/2019	00:00:35	-68.60
22/01/2019	20:00:45	-67.17
11/01/2019	22:00:35	-66.33
29/01/2019	20:01:00	-66.07

Table 1 - 20 highest RoCoF in January 2019

The problem has worsened remarkably during the winter months of 2018 and 2019, with DFDs reaching values higher than 100 mHz daily, and even several times a day. Furthermore, extremely high values of DFD have been reached, e.g. -168 mHz on 6 February 2018 at 20h and -166 mHz on 14 February 2018 at 22.00. Prior to that, only two frequency deviations (stochastic, in 2010 and 2011 with values of around 160 mHz) have reached similar values since the incident in November 2006, which was caused by the split of the CE Synchronous system.

In the beginning of 2019, the DFD amplitudes continued to grow and the problem with DFDs reached a culmination on 10 January. Fig. 7 illustrates the average values of frequency during all days at the same time of day for January 2019. This figure shows the average value for the 31 days, where the frequency is taken each day at the same time.

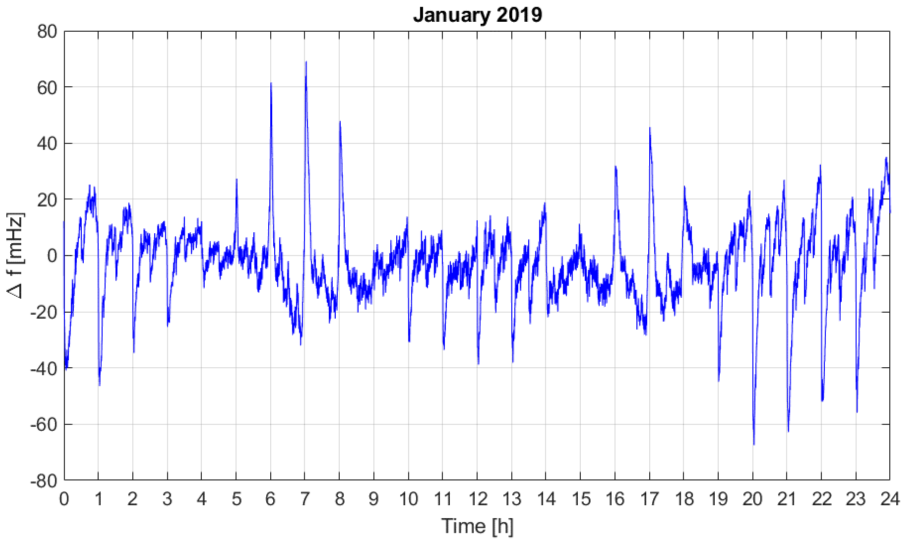


Fig. 7 – Average values of Frequency per time of day for January 2019

The worst (lowest) frequency deviation since November 2006 occurred on 10 January at 21:02. Frequency deviation reached -192 mHz and was the result of the superposition of a strong DFD and the long-term frequency deviation caused by the tie-line measurement error in the AGC controller of TenneT DE.

By comparing the schedule changes of 9, 10 and 11 January (three working days) at 21:00, we can detect that for a few CE TSOs, those changes were extremely high on 10 January 10. Five control blocks had changes above 2 GW at that time, which also overlapped with additional changes in load.

1.3 Impact of Deterministic Frequency Deviations

1.3.1 Impact on system operation

Flow changes: The frequency deviations cause additional unscheduled power flow due to activations of frequency containment reserves that were not foreseen in the reference flow. This results in regular higher loading of transport lines during the hour-changes where DFD occurs.

This means that the remaining capacity of the lines (as foreseen in the reliability margins Transmission Reliability Margin [TRM] or Flow Reliability Margin [FRM]) is used more frequently than only during system outages, for instance, every hour during the DFD, and must be guaranteed to be available at all times.

Misuse of Frequency containment reserves: The DFDs diminish the capability of TSOs to ensure the reliability of the system, as the operational reserve (FCR) is activated to maintain frequency stability.

To mitigate frequency deviations, independently of the structure of frequency control in different synchronous areas, FCR is delivered automatically and the synchronous system subsequently activates additional restoration reserves (FRR). In systems using automatic frequency restoration control, the activation of FRR is proportional to the deviation. The reserves are activated in both directions, dependent on the direction of the frequency deviation, with the highest contributions coming from the control blocks with the highest imbalances at that time.

DFDs have a major influence on reserves in systems which balance on FRCE, as described previously.

$$FRCE = \Delta P + Kri*\Delta f.$$

In CE, for control blocks with a power frequency characteristic constant (Kri) greater than 1000 MW/Hz, a frequency deviation of Δf = ±0.075 Hz implies a reserve activation of ± 75 MW.

For a medium sized TSO carrying 100 MW of FCR, a DFD of 0.075 Hz uses 37.5% of this reserve (0.075 Hz/0.2 Hz) or 37.5 MW for mitigation of inter-hour frequency deviations.

At the CE level, for a calculated power-frequency characteristic constant of 26700 MW/Hz, a frequency deviation of ±0.075 Hz leads to a total FRCE deviation of approx. 2000 MW and a total FCR activation of 1125 MW (37.5% of 3000 MW FCR).

Simply put, during the time that the DFD occurs, the CE system is weaker and could not have sufficient reserves to cover the loss of 3000 MW without dropping below the level of 49.8 Hz

System Damping issues: In situations of low availability of FCR, the damping of inter-area oscillations is also reduced. Figure 8 clearly shows an increase in the amplitude of the oscillation at a higher frequency deviation from the setpoint. This could require additional operational measures and, in some cases, could lead to challenging operational situations such as the loss of generating units and/or system separations. In other words, during the DFD, the electricity system of CE has a slower reaction in responding to oscillations, which may occur at any time, thereby increasing the risk that such oscillations cause additional issues (e.g. possible additional outages) in the system.

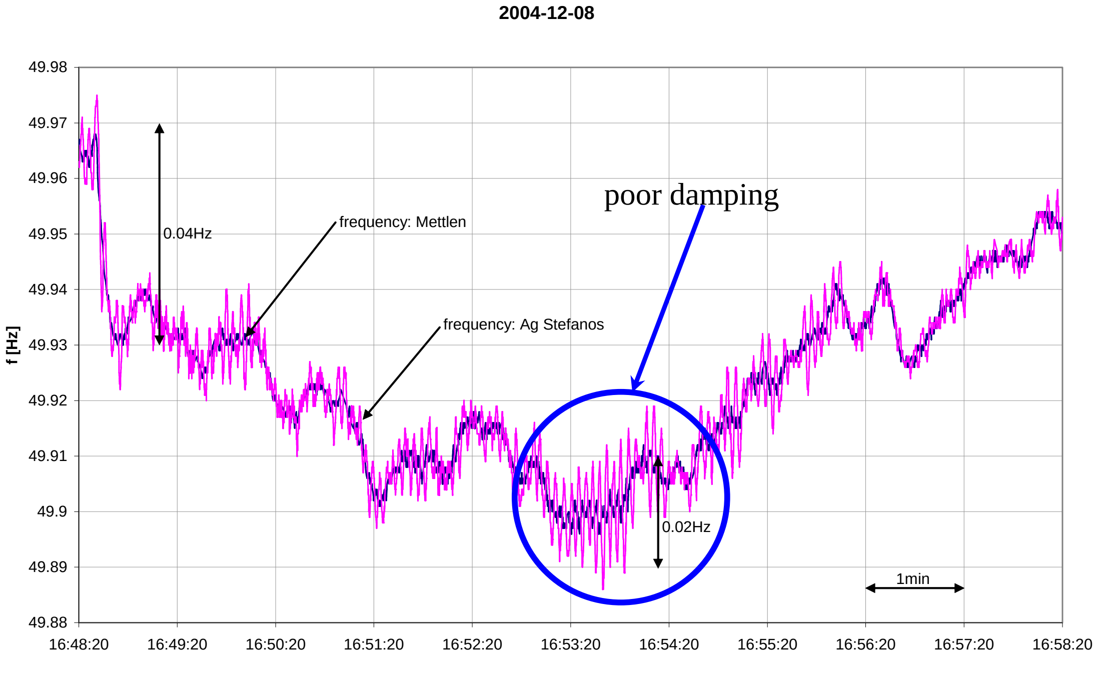


Fig. 8 – Recording of poor damping of inter-area oscillations during frequency excursion [1]

1.3.2 Impact on Market Parties

(a) Synchronous generation

Synchronous generation is designed and tuned to operate efficiently and safely within a limited operational domain defined mainly by frequency and voltage. Frequency limits are a concern for rotating machines, since deviation from the typical frequency ranges can affect generation lifecycle or cause damage.

Depending on the prime-mover and control strategy of such generation sources further constraints can be observed.

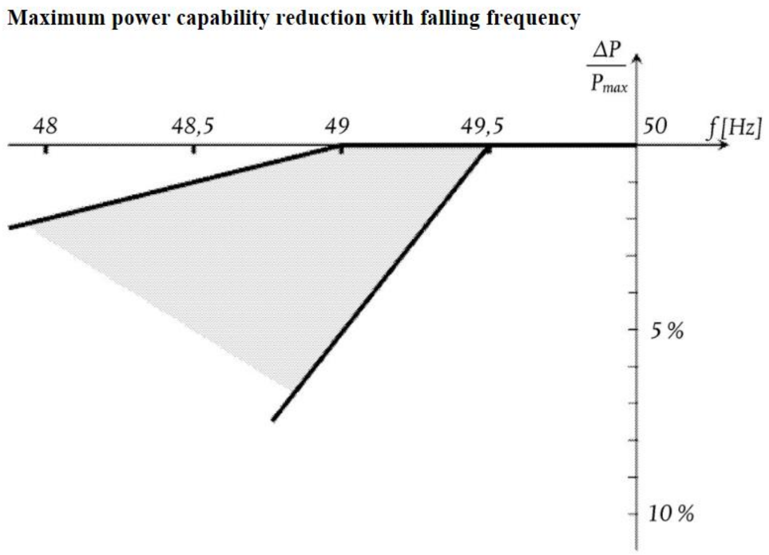


Fig. 9 – Admissible power reduction under falling frequency [2]

The Network Code on requirements for grid connection of generators [2] enables units to reduce their active power injection due to the technical limitations associated with under-frequency deviations, as illustrated in Fig. 9. However, even if the code requirements ask for a larger frequency band conformity, the impact described below shall not be underestimated. This is mainly due to the inherent characteristic of losing some output at a lower frequency (particularly Gas Turbines), i.e. at a lower rotational speed of the synchronous machine. This is not caused by a controller action but purely due to the physical fact that with a lower rotational speed comes a reduced mass flow, which immediately translates into a reduced power output. To maintain the same power output under the same rotational speed, a higher mass flow is required.

(b) Non-synchronous generation

Frequency quality usually does not have a substantial impact on non-synchronous generation (e.g. full-converter wind turbines, PV installations connected via converter or Storage facilities), as these generation types often cover a large band of frequency.

Activation of FCR in large quantities for more and longer periods leads to higher wear and tear of production units. Structural activation without the occurrence of outages is considered ‘abuse’ and can lead to installation problems for production companies. These effects are a disincentive from keeping the frequency controller in service and increases the (acquirement) cost of FCR.

2 Main causes of Deterministic Frequency Deviation

DFDs have been increasingly occurring in the CE Synchronous system over the last few years, like other Synchronous Areas which have introduced energy markets.

The causes of the DFDs were identified to be:

I. A weakening in the strong link between power consumption and power generation dynamics. With the liberalisation of the EU energy market, the market rules between generation and consumption are based on the exchange of energy blocks of fixed time periods.

II. The physical ramping which is applied on generation and load is not aligned between all market participants. The resulting imbalances are reflected in the frequency deviations.

III. There is also the rule for BRPs to be balanced over the whole MTU, which leads to effects whereby they will adjust their production at the latest point in time by the fastest gradient possible.

IV. Local legislation can cause rapid changes in generation or load at specific hours (noise emission constraints, night tariff changes, …)

2.1 Hourly schedule changes

There is a significant correlation between on the one hand the size of changes in schedules within control areas / market bidding zones and on the other hand the number of DFDs observed. Indeed, we have observed evidence of a significant increase of both market activity and frequency deviations from 2001 to 2018, Fig. **10 –**0 illustrates the sum of the hourly schedule absolute changes within the UCTE North, East and West regions from 2008 until 2018, with a sustained increase in magnitude with a direct correlation to the DFD figures. In addition, we observe that frequency deviations occur more frequently in winter than in summer, which is again reflected in the changes in schedule which are higher in winter than in summer.

Figure 10 below gives a view of the amplitude of schedule changes. This graph is made by examining the change in net position of each control area hour per hour in absolute value and adding the numbers together. The changes in the net position of the synchronous area, which do not correspond directly to the slower evolving load, cause the DFDs. These changes in the net position of the synchronous area are reflected in changes in the net positions of the individual control areas. However, it must be noted that a change in the net position of one area could be compensated by an opposite change in the net position of another area, which should not lead to a DFD.

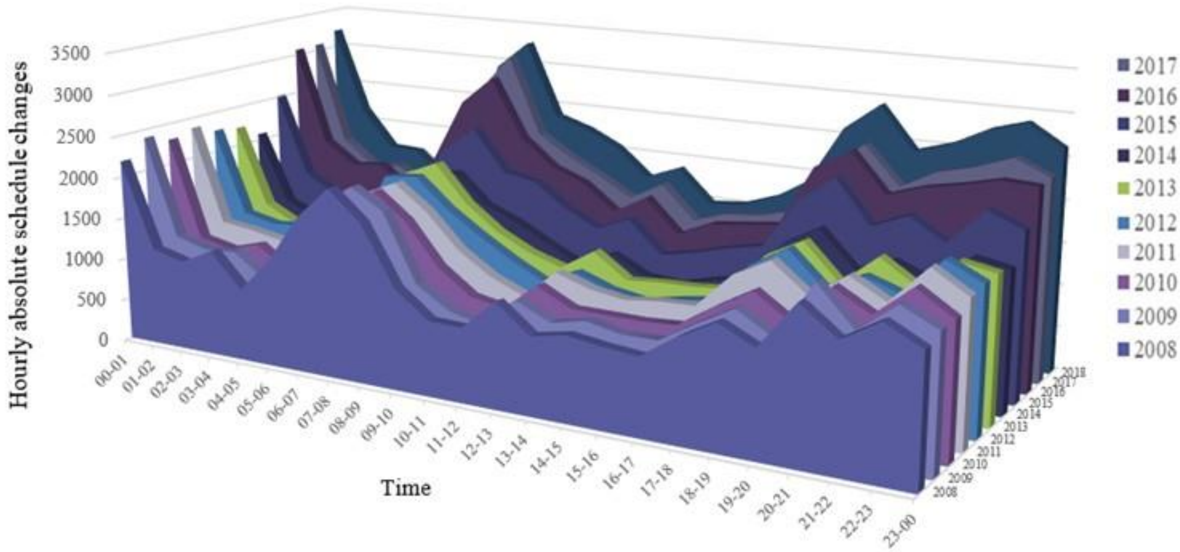


Fig. 10 – Total delta in hourly schedules for within CE (UCTE North, East and South)

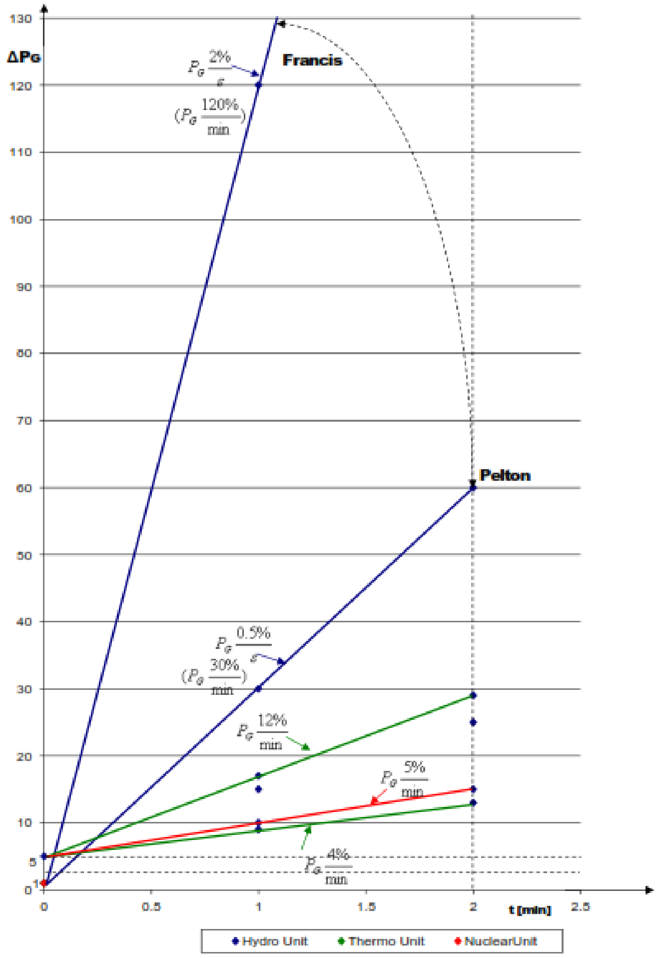
2.2 Fast acting vs slow acting production units

As the number of changes in schedules increases, the number of changes in the generation mix increases too. If one unit reacts faster than another, this also implies imbalances and frequency deviations due to the mismatch of ramps.

- Fast unit's behaviour is near a power step without correspondence in real load. In this manner, the hourly behaviour of fast units is quite similar to an incident. The impact on system frequency is in relation to schedule steps, leading to frequency deviation in the whole system.

- Slow units are faced with opposite requirements: technical requirements which impose the natural ramp and commercial ones which impose the delivery of scheduled energy in the time frame.

  Both behaviours contribute to frequency deviations.



A programme change would be mainly impacted by generation response time, where we can distinguish:

(i) Fast scheduling:

HVDC 100 MW / min

Hydro 20..100 % / min

Gas 6..10 % / min

(ii) Slow scheduling:

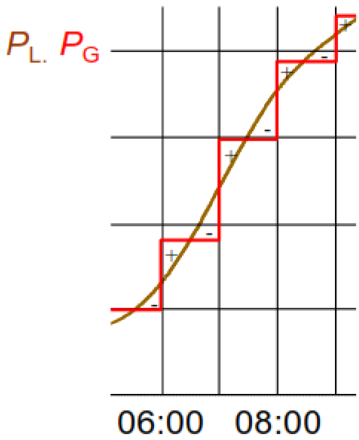
Nuclear 2..4 % / min

Coal 1..2 % / min

Load 0.1... 0.5 % /min

Fig. 11 – Total delta in schedules for UCTE North and UCTE South [1]

2.3 Incompatibility between load ramping and block schedules



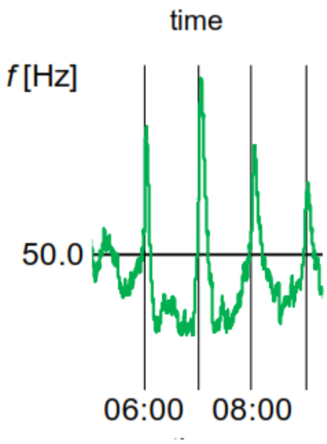


Fig. 12 – Effect of difference between load and schedules on frequency

Such behaviour occurs on a large scale typically during large demand variation that occurs in the morning and evening. Whereas the demand varies in continuous fashion, the incentive for BRPs and generators is to follow as closely as possible the block shape. This results in an imbalance between the load and the generation. Such power deficit resulting in 'stepwise' imbalance cannot be balanced by control energy at any reasonable cost; as a consequence, the frequency can rise instantly and drop again within the hour. Such power excesses and deficits depend on the Market Time Unit (MTU) on the day-ahead and intraday markets (currently MTU = 1 hour; due to evolve towards 15 minutes) and depend on the ISP. (currently 1 hour, 30 minutes or 15 minutes; due to evolve towards 15 minutes).

Traditionally, in vertically integrated energy systems, system operators scheduled generation in ramps according to their best estimate of the demand. This represents the most efficient way to schedule generation as it reduces the regulating needs to a minimum. However, since the end of the mandatory pool e.g. in the UK, demand-side bidding has been the rule and generation is scheduled to fit the demand purchases. Imbalance settlement provides incentives to make the best forecast of the demand possible. However, these forecasts have a time resolution equal to the ISP (15 min, 30 min or 1 h) and are therefore designed to predict average load values. The averaging of the load over the ISP leads to the instantaneous imbalances which cause the DFDs.

2.4 Behavior of generation units following block-shaped incentives

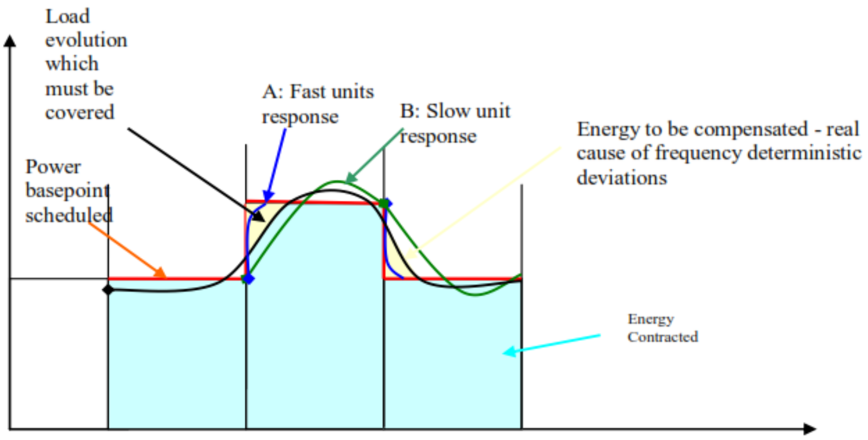


Fig. 13 – Unit behaviour in scheduled time frames [3]

During the morning ramp, the stepwise increase in generation followed by the slower continuous increase in load results in a power imbalance. This 'stepwise' imbalance cannot be possibly balanced by aFRR or mFRR due to the full activation time, which is slower than 5 minutes; in consequence the frequency rises instantly and drops again below 50 Hz over the hour. It must be noted that these root causes for the DFDs are expected to increase in the future with the higher penetration of fast units (e g batteries).

This behaviour can be linked to the fundamental difference in control target for BRPs and for TSOs: in most CE synchronous systems, market participants or BRPs deliver and buy energy (on an hourly or half-hourly, or quarter-hourly basis) whereas the TSOs control real-time power balance. Furthermore, BRPs are treated to be balanced over the whole ISP and therefore react at the latest point and as fast as they can to change their production.

2.5 Ramping on HVDC lines

Difference in ramping rates on HVDC cables, compared with each other and compared with the ramping rates put on the FRCE control inside CE (of +/- 5 minutes) can also contribute to the DFD.

Suppose a change in set-point on GB-BE cable from +1000 to -1000 MW and suppose the full programme change is going through Belgium to other bidding zones, such that it is reflected on the AC borders of Belgium as a 2000 MW programme change as well.

Given the ramp rate of +/- 5 minutes on the AC borders and 100 MW / min on the GB-BE cable, this leads to the following contribution to the FRCE-open loop in the Belgium control area that would need to be compensated by the activation of aFRR and mFRR, but this might be too slow to react to the ramping.

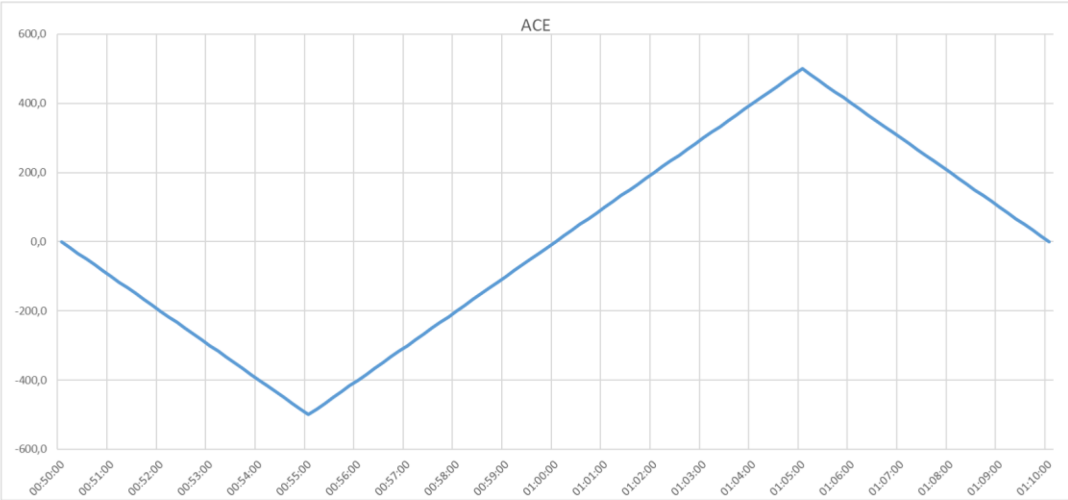


Fig. 14 – Effect of HVDC ramping on the FRCE of the Belgian Control area

The issue is currently under investigation.

3 Managing the problem

3.1 Expected frequency quality

3.1.1 Setting the target of maximum DFD

ENTSO-E proposes establishing which size of DFD is detrimental to the security of the power system, and which DFD size can be considered as acceptable. The target will be used to check if the proposed solutions are adequate to reduce the size of DFD to the acceptable level.

The proposal of an acceptable DFD size comes from the realisation that it will be virtually impossible to completely eliminate the DFD as there will always be a remaining mismatch between the accounting schemes of balancing and the load curve which changes constantly and smoothly.

First Target: Maximum Frequency Deviation

In a CE synchronous area, a DFD should allow the occurrence of the defining incident of FCR without going below 49.8 Hz, which means the frequency deviation should always be smaller than 200 mHz.

The dimensioning incident (double outage of power plants) of FCR is 3000 MW which causes a quasi-stationary frequency deviation of (3000 MW / 27000 MW/Hz) approx. 115 mHz for standard conditions. However, sometimes load/production is higher or lower and the regulating power of the system is also sometimes higher and lower.

Therefore, expected frequency deviation would be in an interval of 100 to 125 mHz.

The total margin should therefore be 125 mHz.

To maintain a margin of 125 mHz, the absolute frequency deviation caused by a DFD should never be larger than 75 mHz.

This leads to an acceptable DFD = 75 mHz

Second Target: Frequency Outside Interval range of SOGL

A second target could be related to the quality target which is given in SO GL:

Article 127 and Annex III of SO GL specify frequency quality defining parameters in CE, establishing +/- 50 mHz as the standard frequency range, which shall not be exceeded during more than 15,000 minutes per year.

This volume covers both the DFDs and the frequency deviations due to outages in the power system. Given that there are statistically less than 100 large outages per year and more than 2,500 DFDs per year, most of the 15,000 minutes will be used by DFDs.

Considering that there are daily about 7 large DFDs, the duration of the DFD above an absolute frequency deviation of 50 mHz should not be longer than 5 minutes per DFD in order to avoid violating this SOGL target.

Therefore, a second target could be:

A DFD should not leave the interval of +/- 50 mHz for more than 5 minutes

3.1.2 How to monitor the target

The synchronous area monitor can take the responsibility of monitoring the target per analogy to articles 128-132 of the SO GL.

The System Frequency SG will set up the necessary reporting to follow the actual DFDs observed during the DFDs and to count the number of times the targets have been triggered.

In a first step, a simplified approach could be to follow the most critical time stamps (each day, the hours 00, 06, 07, 21, 22 and 23).

In addition, it is recommended, from now on, to follow the actual RoCoF observed during the DFDs and count the number of times that this RoCoF is above 2, 3, 4, 5 and 6 mHz / second.

As we know from the statistics that this RoCoF is steadily increasing, it is very important to keep track of this and to see at which rate we are reaching the average speed of activation of FCR, which is currently 200 mHz in 30 seconds.

3.2 Expected FRCE quality

The SO GL and SAFA Policy on Load-Frequency Control and Reserves define FRCE quality targets, to ensure frequency quality in the synchronous area CE. These FRCE quality targets, defined on a 15-min basis, are good at identifying the contributions of each TSO to frequency deviations, which last for a significant amount of time, in order to be reflected in the 15-min average values.

Since DFDs have a short duration in relation to this 15-min period, there is a loss of information through the averaging process. This has the following consequences:

- The 15-min FRCE quality targets do not reflect the individual contributions of each TSO to DFDs. This especially applies to systematic contributions, so that the TSOs are potentially unaware if and how much they contribute to DFDs on a regular basis.
- The analysis of individual DFDs is made on an 'ad-hoc' basis: only in cases where DFDs played a significant role, i.e. the 10th of January.

The best indicator for the operational contributions of TSOs to DFDs is the FRCE calculation on a maximum 10 second basis:

- It allows a systematic evaluation of TSO contributions to DFDs. Thus, systematic contributions from specific TSOs can be identified.
- TSOs can therefore perform a detailed analysis of their contributions to DFDs and define tailor-made solutions for any local issues, which have an added value to the already known causes and proposed solutions.
- Situations with high DFDs can be identified easily and analysed.

The definition of FRCE quality targets should be made on the basis of ‘instantaneous’ measurements (measurement interval maximum 10 sec), in line with the quality targets for the frequency, as given above.

- Such a target sets the basis for the reduction of DFDs, as it defines acceptable behaviour during DFDs and gives clear guidance for when mitigation and alleviation measures should be taken by the TSOs. The quality target should be tailor-made for certain DFD-prone times, i.e. hour changes (±5 minutes).

Based on these quality targets, the TSOs can choose the most effective and efficient measure to reduce its contribution to DFDs, considering the respective particularities of the LFC Block in terms of market design and technical capability.

4 Possible solutions

4.1 How are DFD already managed today

Between 2013 to 2016 measures (due to recommendations from the ENTSO-E Eurelectric Joint Investigation Team [1]) were implemented to improve the frequency quality. For instance, a market time unit of 15 minutes was introduced in 2012 in Germany and unit ramping was also introduced in the Italian market.

4.1.1 GB

In GB, spot power balancing is carried out. The demand is matched by active power, in theory, second by second through market mechanisms in the balancing mechanism. A 300 MW mismatch in power with demand can lead to the frequency breaching the operational limits of 0.2 Hz (i.e. outside the standard frequency range in SOGL). This method removes large mismatches causing large frequency deviations due to market mismatch. This is also known as Residual Central Dispatch and takes place after in day gate closure i.e. the market meets settlement period energy requirements and residual central dispatch is used to meet spot power requirements within the settlement period.

The market participants are obliged legally and contractually to provide certain automatic acting ancillary services to balance the frequency in real time.

Mandatory Frequency Response

The mandatory frequency response (MFR) is an automatic change in active power output in response to a frequency change by providing continuous dynamic modulation in power responses via synchronised generation through their automatic governing systems with a 3 to 5 percent governor droop characteristics. This is a mandatory service that must be provided as a part of the connection agreement with the TSO. Providers can offer one or a combination of the following response times:

* Primary Response (Available within 10 seconds & sustained for a further 20 seconds)

* Secondary Response (Available within 30 seconds & sustained for a further 30 minutes)

* High Response (Available within 10 seconds & sustained indefinitely)

This frequency response can be activated by sending an electronic instruction to any participating generator operating in Frequency Sensitive Mode unless they declare limitations (commissioning, maintenance) also called ‘Limited Frequency Sensitive Mode’ where after 50.4 Hz they drop 2% of their output for every 0.1% deviation in system frequency.

Firm Frequency Response

The firm frequency response (FFR) is a commercial service that can provide the GB TSO with both a dynamic and non-dynamic response to change in frequency during a particular window of time. The dynamic frequency service provides a continuous modulation to changes in system frequency, whereas the non-dynamic service is triggered by the operation of a Low Frequency Relay when the frequency deviation activates that relay. This service can include generators connected to the transmission and distribution systems, battery storage providers, HVDC interconnector support and aggregated demand side response that consists of interruptible load contracts which automatically reduce/disconnect load when triggered by a Low Frequency Relay.

Enhanced Frequency Response

The enhanced frequency response (EFR) is a dynamic service where the active power changes proportionally in response to changes in system frequency. The participants of this service must be capable of responding within one second to frequency deviations and operate in frequency sensitive mode within the operational envelope.

Reserve Services

Fast Reserve

Fast reserve provides the rapid and reliable delivery of active power through increasing output from generation or reducing consumption from demand sources via electronic instruction form the national balancing engineer during their contracted service windows, with a reserve rate in excess of 25 MW / min. This type of reserve has a droop characteristic of 1% to 4% based on their reserve contracts. Fast reserve utilisation can vary depending on system conditions, the demand profile and the generating plant on the system. However, on average, providers are utilised for approximately 5 minutes at a time, ten times a day. The providers are expected to have the capability to sustain reserve for at least 15 minutes.

Short Term Operating Reserve

The short term operating reserve (STOR) service is provided by units greater than 3 MW that are typically used to replace eroded frequency response following a frequency deviation, demand mismatch or generation uncertainty. These units are instructed using a single point dispatch tool used by the TSO typically available within 20 minutes and could be sustained for at-least two hours thereafter.

Additional Pumped Storage Services

In addition to pumped storage participating in the above services, they also provide certain services (at an initiating/holding cost to the TSO) to help mitigate frequency deviation by increasing their output at a near instantaneous run up rate to full output. These services play a pivotal role in arresting the deviation of system frequency and restoring it back to its operational limits.

Part Loaded Response (PLR)

This is a dynamic FFR service provided by certain hydro units that are contracted to be part loaded and generate up to their full output during a frequency deviation, providing a fast response at a default droop setting of 1%

SpinGen on LF

This is a static response service provided by pumped storage units that is triggered by a low frequency relay operation at 49.75 Hz, which allows the valves of the pumped storage unit to open and the unit to generate to its full output at a run up rate of 999 MW / min. For this service to operate, the turbines of the unit needs to be spinning in air in preparation for the valves to open to provide a faster response.

Pump on LF

Some hydro power plants can be used in load mode (using pump to store water). They are used in load mode when demand is low (to store water in anticipation to further needs). Hydro Pump Storage can also be used in cased of frequency deviation: stop pumping in case of under-frequency, and even start in generation mode if frequency continues to decrease, depending on their build. Like the SpinGen, these pumping loads can be disconnected by a low frequency trigger typically set at 49.75 Hz. The response rate is instantaneous and plays a pivotal role in arresting and restoring system frequency.

4.1.2 Nordic

Based on the planning information and real-time information, each TSO assesses the impact of ramping around hour shifts from a national perspective. In addition, Svenska Kraftnät and Statnett assess whether the changes in production plans in the Nordic area and the HVDC exchange around the hour shift will impact the system frequency in a way that cannot be entirely handled by control centres in the minutes before and after the operating hour. If so, there is a need to advance or delay parts of planned production steps at the hour shift. The power schedules may be changed from 30 minutes before hour shift till 30 minutes after the hour shift.

This coordination is mainly important during morning and evening hours and also around day shift. If the changes in the production plans are deemed to be too high, the TSOs make a coordinated plan on how to level out these changes by an agreement with BRPs that represent power generating modules to reschedule the production. In situations with congestions, there is also a need to decide in which order the rescheduling should take place. For example, in the event of close to congestion on Hasle from Norway to Sweden, it may be wise to start with increased production in Sweden/Finland 15 minutes before the hour shift and decreased production in Norway in the first 15 minutes after the hour shift. The volumes to be shifted after the hour might be reassessed closer to the hour shift if something unplanned occurs that would interfere with the initial plan.

The trading plans on the HVDC interconnectors between the Nordic LFC block and other LFC blocks can potentially change so much from one hour to the next that the changes in power flows at the change of hours must be restricted to manage balance regulation and to stay within system security limits. Restrictions are placed on the gradient for change in flow and on changes to the trading plans from one hour to the next in the energy market

The current capacity on HVDC-connections between the Nordic synchronous system and the CE synchronous system is 5340 MW. The Nordic system is about 1/5 as large as the Continental system. This – together with the fact that the flow pattern on the connections behaves like consumption seen from the Nordic system (more export in the morning and opposite in the evening) – leads to HVDC connections having a much larger impact on the Nordic system than the Continental system. The variation in exchange on those connections is more and more synchronised, resulting in price variations in the two systems in the day-ahead markets. Due to this, there are potential risks for up to 10,000 MW change in flow on those cables at the one hour shift. Such a change in schedule could lead to a huge, unmanageable RoCoF in the Nordic Area.

To avoid this threat to system security, the Nordic TSOs agreed to restrict possible changes in the exchange on each cable connection to a maximum 600 MW from one hour to the next in all time frames (including the day-ahead market). Currently, this allows for up to 5–6,000 MW changes in exchange at any one hour shift. The TSOs are monitoring the economic consequences of this restriction and comparing them with other alternative actions such as extra reserves, counter trade in the market, etc. The goal is to find the best socioeconomic solution. There is also a restriction on the gradient for changed flow on the individual connection (max 30 MW / min giving a total of about 200 MW / min for the synchronous system).

The restrictions in power change between hours is to control the frequency in the Nordic area, and the restrictions in ramp rates are to control the voltage in the local areas where the HVDC links are implemented.

4.1.3 Switzerland

Switzerland has a – requirement in national grid code (Transmission Code) & accounting of inadvertent exchanges based on the schedule change ramping (-/+ 5 min)

In fact, the schedules for the calculation of the inadvertent exchanges are ‘corrected’ in such a way that they already contain the -/+ five minutes ramp around the changing of the schedules. By doing so, an incentive was created in order to avoid penalising those market participants who follow the change of schedule ramping as required in the grid code. This is given in more detail in the solution, ramping on schedules.

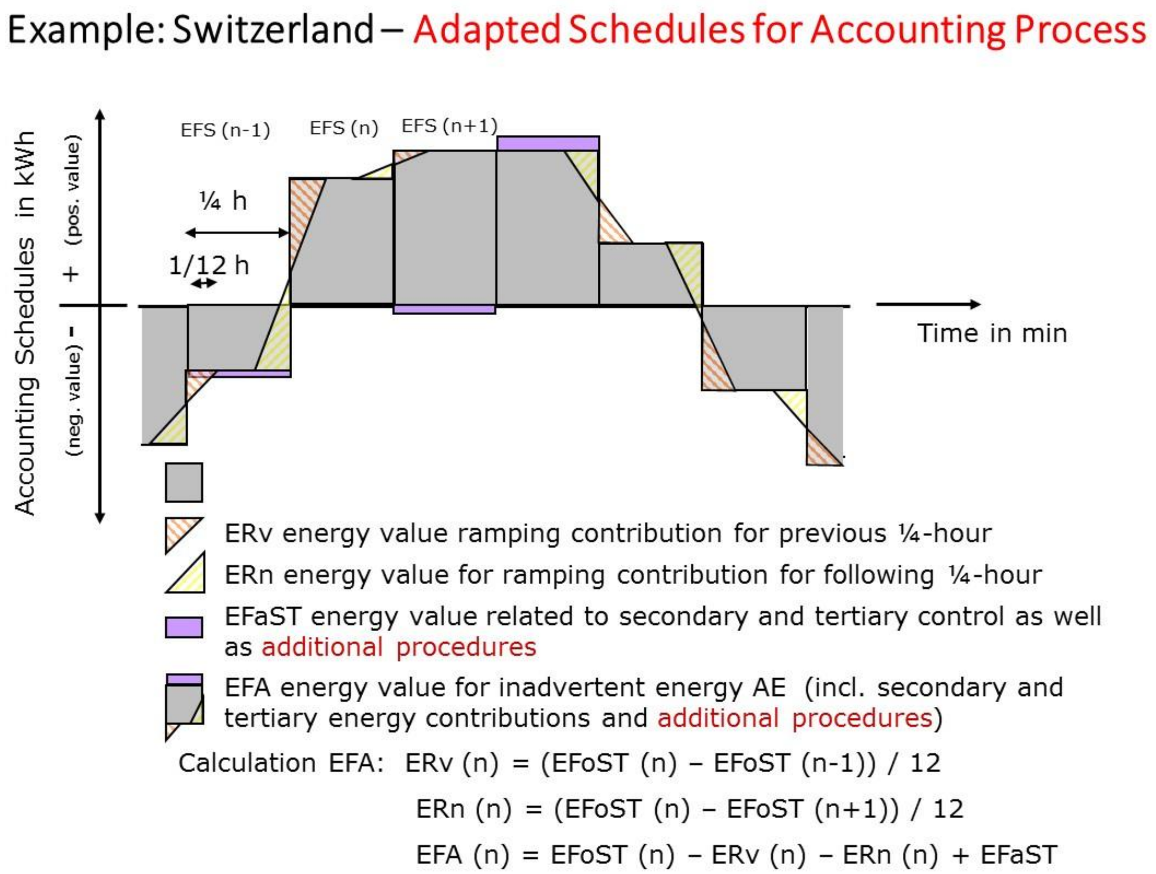


Fig. 15 – Ramping on schedules applied in Switzerland

4.1.4 Spain

In Spain, aFRR provision is made through large regulating areas (acting as BSPs), which can aggregate several generation units from different technologies (e.g. hydro + thermal + wind). The verification of the provision of the service at 'regulating area' level (portfolio) guarantees that, regardless of the possible technical restrictions of the units behind (i.e. thermal), the joint provision ensures the answer asked by the TSO (in terms of power). In addition, the commitment of each regulating area is continuously taking into account the action of the other regulating areas, so they have an economic incentive to give a faster response (i.e. for 'extra' provision there can be a bonus, whereas for slower provision a penalty is applied). This has resulted in a very good functioning of aFRR provision in the Spanish system and thus in small DFDs.

4.1.5 France

RTE monitors continuously the amount of reserved capacity available in the LFC Block (procured aFRR and mFRR, plus additional mFRR and RR free bids) and takes measures to replenish or release reserve capacities when necessary in order to always have at least the dimensioning volume.

Regarding the aFRR and FCR provided, RTE ensures in real time that providing units are correctly delivering FCR and aFRR and takes measures to replenish reserves in case the providing units (even if scheduled by BSP) are not correctly providing FCR or aFRR.

The k-factor is re-estimated every 30 minutes and (if larger than the default value, as established yearly by the RG CE Sub-Group System Frequency) adapted in the secondary controller.

4.1.6 Germany

The introduction of quarter-hourly resolution for MTU in the German Intraday-Market leads to a decrease of deterministic imbalances at the change of the hour, but to an increase at every change of quarter-hour.

The improvement of the imbalances contributing to DFDs in Germany after the introduction of a MTU of 15 minutes can be seen in figures 16 and 17. Figure 16 shows that the aFRR need in Germany before the introduction of a 15 minute MTU experienced high peaks during the change of the hour. In figure 17, the peaks have been significantly reduced. However, as mentioned before, some peaks can be experienced with the change of quarter hour (see 08:30 on 2nd January 2016).

That the introduction of a 15 minute MTU does not completely avoid the contribution to DFDs as can be clearly seen in figure 18, showing the behavior of the aFRR need in the German LFC block on the 30 April 2018. High peaks with the change of the hour or quarter hour are still occurring, especially in the morning and evening hours. Therefore, Germany is still contributing to DFDs, especially in the morning and evening hours. The contribution is based on several reasons:

- shut down and startup of wind due to environmental protection (bats, noise,…)
- contribution of large water pump storages, which change from pump to turbine and vice versa in ~1 minute
- high rate of change of load

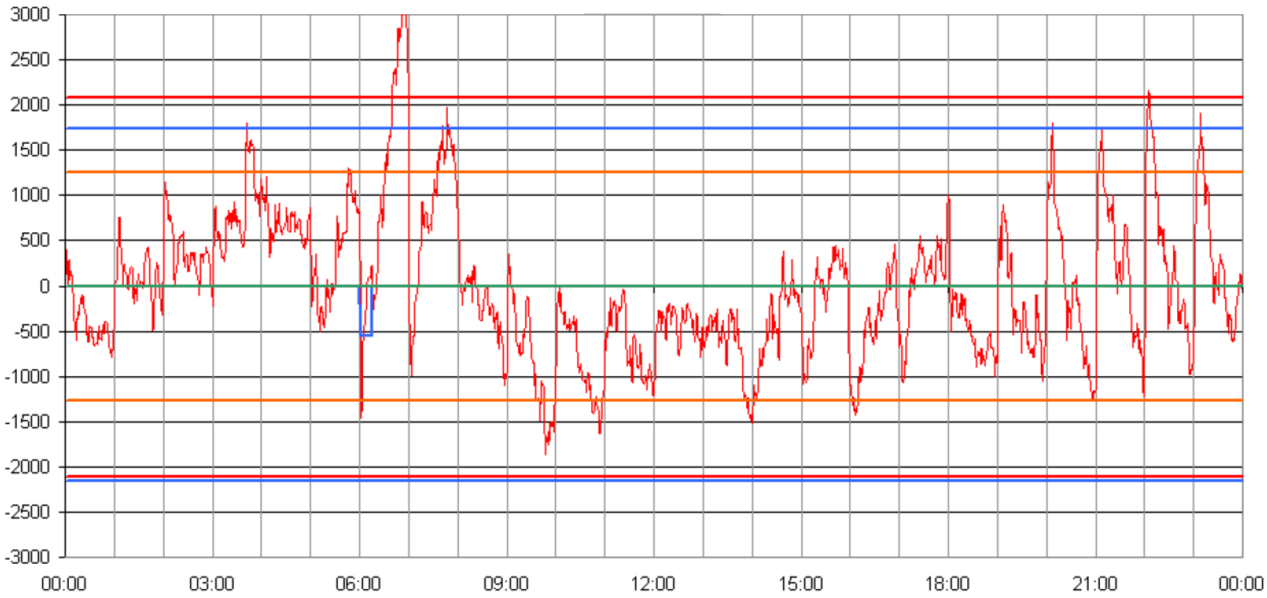


Fig. 16 – Behavior of aFRR need in German LFC block on 16th January 2012 (before introduction of 15 minute MTU)

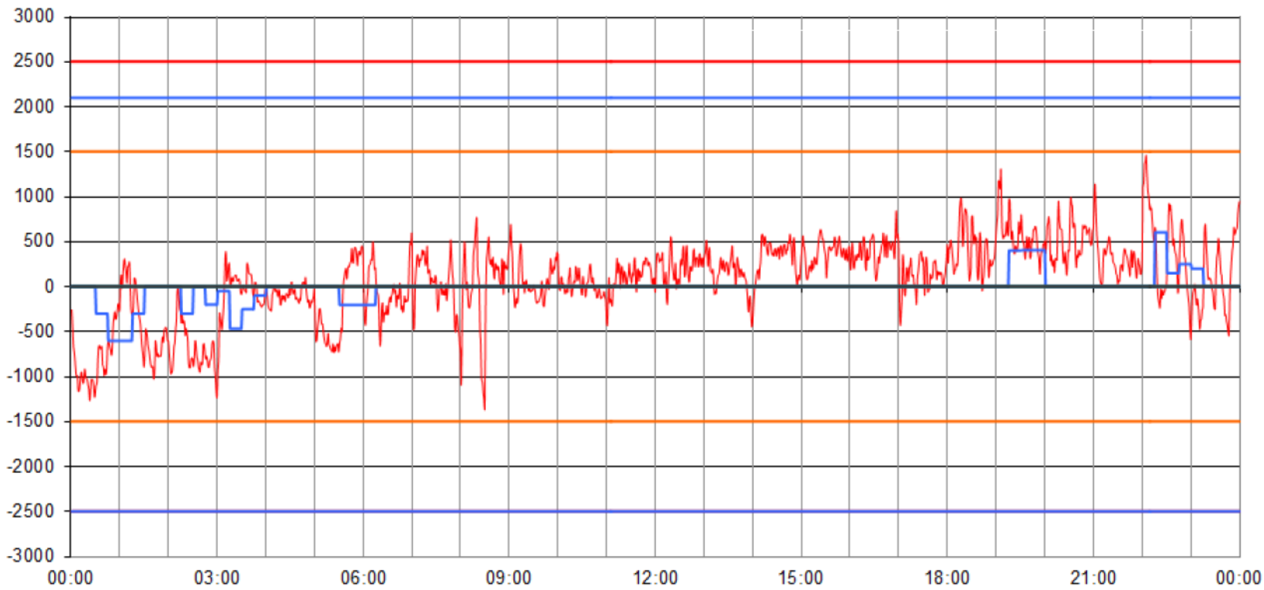


Fig 17 – Behavior of aFRR need in German LFC block on 02.01.2016 (after introduction of 15 minute MTU)

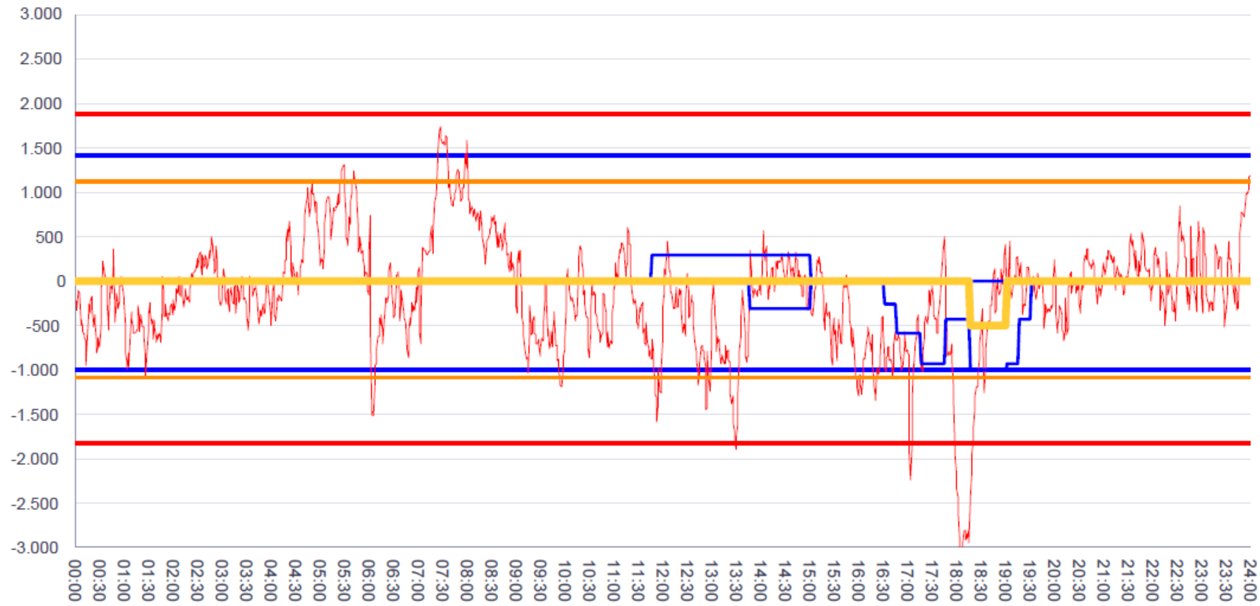


Fig. 18 – Behavior of aFRR need in German LFC block on 30th March 2018 (after introduction of 15 minute MTU)

4.1.7 Denmark

Energinet has requirements for all new production units to have a ramp rate limiter. Only for batteries is there a limit of max 100 kW / s.

4.2 Regulatory Framework

Extract from RfG NC:

Article 15

General requirements for type C power-generating modules

6.(e) the relevant system operator shall specify, in coordination with the relevant TSO, minimum and maximum limits on rates of change of active power output (ramping limits) in both an up and down direction of change of active power output for a power-generating module, taking into consideration the specific characteristics of prime mover technology

Extract from SO GL:

Article 127

Frequency quality defining and target parameters

3. The default values of the frequency quality defining parameters listed in paragraph 1 are set out in Table 1 of Annex III.

4. The frequency quality target parameter shall be the maximum number of minutes outside the standard frequency range per year per synchronous area and its default value per synchronous area are set out in Table 2 of Annex III.

5. The values of the frequency quality defining parameters in Table 1 of Annex III and of the frequency quality target parameter in Table 2 of Annex III shall apply unless all TSOs of a synchronous area propose different values pursuant to paragraphs 6, 7 and 8.

6. All TSOs of CE and Nordic synchronous areas shall have the right to propose in the synchronous area operational agreement values different from those set out in Tables 1 and 2 of Annex III regarding:

(a) the alert state trigger time;
(b) the maximum number of minutes outside the standard frequency range.

7. All TSOs of the GB and IE/NI synchronous areas shall have the right to propose in the synchronous area operational agreement values different from those set out in Tables 1 and 2 of Annex III regarding:

(a) time to restore frequency;
(b) the alert state trigger time; and
(c) the maximum number of minutes outside the standard frequency range.

8. The proposal for modification of the values pursuant to paragraph 6 and 7 shall be based on an assessment of the recorded values of the system frequency for a period of at least 1 year and the synchronous area development and it shall meet the following conditions:

Annex III - *Table 1* **Frequency quality defining parameters of the synchronous areas**

Table 1

Frequency quality defining parameters of the synchronous areas

	CE	GB	IE/NI	Nordic
standard frequency range	± 50 mHz	± 200 mHz	± 200 mHz	± 100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1 000 mHz	1 000 mHz
maximum steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
frequency recovery range	not used	± 500 mHz	± 500 mHz	not used
time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	± 200 mHz	± 200 mHz	± 100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

Frequency quality target parameters referred to in Article 127:

Table 2

Frequency quality target parameters of the synchronous areas

	CE	GB	IE/NI	Nordic
maximum number of minutes outside the standard frequency range	15 000	15 000	15 000	15 000

Article 128

FRCE target parameters

1.All TSOs of the CE and Nordic synchronous areas shall specify in the synchronous area operational agreement the values of the level 1 FRCE range and the level 2 FRCE range for each LFC block of the CE and Nordic synchronous areas at least annually.

2.All TSOs of the CE and Nordic synchronous areas, if consisting of more than one LFC block, shall ensure that the Level 1 FRCE ranges and the Level 2 FRCE ranges of the LFC blocks of those synchronous areas are proportional to the square root of the sum of the initial FCR obligations of the TSOs constituting the LFC blocks in accordance with Article 153.

3.All TSOs of the CE and Nordic synchronous areas shall endeavour to comply with the following FRCE target parameters for each LFC block of the synchronous area:

(a) the number of time intervals per year outside the Level 1 FRCE range within a time interval equal to the time to restore frequency shall be less than 30 % of the time intervals of the year; and

(b) the number of time intervals per year outside the Level 2 FRCE range within a time interval equal to the time to restore frequency shall be less than 5 % of the time intervals of the year (…)

Article 131

Frequency quality evaluation criteria

1.The frequency quality evaluation criteria shall comprise:

(a) for the synchronous area during operation in normal state or alert state as determined by Article 18(1) and (2), on a monthly basis, for the instantaneous frequency data:

(i) the mean value;

(ii) the standard deviation;

(iii) the 1-,5-,10-, 90-,95- and 99-percentile;

(iv) **the total time in which the absolute value of the instantaneous frequency deviation was larger than the standard frequency deviation**, distinguishing between negative and positive instantaneous frequency deviations;

(v) **the total time in which the absolute value of the instantaneous frequency deviation was larger than the maximum instantaneous frequency deviation**, distinguishing between negative and positive instantaneous frequency deviations;

(vi) **the number of events in which the absolute value of the instantaneous frequency deviation of the synchronous area exceeded 200 % of the standard frequency deviation** and the instantaneous frequency deviation was not returned to 50 % of the standard frequency deviation for the CE synchronous area and to the frequency restoration range for the GB, IE/NI and Nordic synchronous areas, within the time to restore frequency. The data shall distinguish between negative and positive frequency deviations;

(b) for each LFC block of the CE or Nordic synchronous areas during operation in normal state or alert state in accordance with Article 18(1) and (2), on a monthly basis:

(i) for a data-set containing the average values of the FRCE of the LFC block over time intervals equal to the time to restore frequency:

— the mean value,

— the standard deviation,

— the 1-,5-,10-, 90-,95- and 99-percentile,

— the number of time intervals in which the average value of the FRCE was outside the Level 1 FRCE range, distinguishing between negative and positive FRCE, and

— the number of time intervals in which the average value of the FRCE was outside the Level 2 FRCE range, distinguishing between negative and positive FRCE

(ii) for a data-set containing the average values of the FRCE of the LFC block over time intervals with a length of one minute: the number of events on a monthly basis for which the FRCE exceeded 60 % of the reserve capacity on FRR and was not returned to 15 % of the reserve capacity on FRR within the time to restore frequency, distinguishing between negative and positive FRCE;

Article 137

Ramping restrictions for active power output

1. All TSOs of two synchronous areas shall have the right to specify in the synchronous area operational agreement restrictions for the active power output of HVDC interconnectors

between synchronous areas to limit their influence on the fulfilment of the frequency quality target parameters of the synchronous area by determining a combined maximum ramping rate for all HVDC interconnectors connecting one synchronous area to another synchronous area.

3. All connecting TSOs of an HVDC interconnector shall have the right to determine in the LFC block operational agreement common restrictions for the active power output of that HVDC interconnector to limit its influence on the fulfilment of the FRCE target parameter of the connected LFC blocks by agreeing on ramping periods and/or maximum ramping rates for this HVDC interconnector. Those common restrictions shall not apply for imbalance netting, frequency coupling as well as cross-border activation of FRR and RR over HVDC interconnectors. All TSOs of a synchronous area shall coordinate these measures within the synchronous area.

4. All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE target parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:

(a) obligations on ramping periods and/or maximum ramping rates for power generating modules and/or demand units;

(b) obligations on individual ramping starting times for power generating modules and/or demand units within the LFC block; and

(c) coordination of the ramping between power generating modules, demand units and active power consumption within the LFC block.

Article 138

Mitigation

Where the values calculated for the period of one calendar year concerning the frequency quality target parameters or the FRCE target parameters are outside the targets set for the synchronous area or for the LFC block, all TSOs of the relevant synchronous area or of the relevant LFC block shall:

(a) analyse whether the frequency quality target parameters or the FRCE target parameters will remain outside the targets set for the synchronous area or for the LFC block and in case of a justified risk that this may happen, analyse the causes and develop recommendations; and

(b) develop mitigation measures to ensure that the targets for the synchronous area or for the LFC block can be met in the future.

Article 16

Annual report on load-frequency control

1. By 30 September, ENTSO for Electricity shall publish an annual report on load-frequency control based on the information provided by the TSOs in accordance with paragraph 2. The annual report on load-frequency control shall include the information listed in paragraph 2 for each Member State.

2. Starting from 14 September 2018, the TSOs of each Member State shall notify to ENTSO for Electricity, by 1 March every year, the following information for the previous year:

a) the identification of the LFC blocks, LFC areas and monitoring areas in the Member State;

b) the identification of LFC blocks that are not in the Member State and that contain LFC areas and monitoring areas that are in the Member State;

c) the identification of the synchronous areas each Member State belongs to;

d) the data related to the frequency quality evaluation criteria for each synchronous area and each LFC block in subparagraphs (a), (b) and (c) covering each month of at least 2 previous calendar years;

e) the FCR obligation and the initial FCR obligation of each TSO operating within the Member State covering each month of at least 2 previous calendar years; and

f) a description and date of implementation of any mitigation measures and ramping requirements to alleviate deterministic frequency deviations taken in the previous calendar year in accordance with Articles 137 and 138, in which TSOs of the Member State were involved.

Extract from EBGL:

Article 18

Terms and conditions related to balancing

6. The terms and conditions for balance responsible parties shall contain:

(l) where existing, the provisions for the exclusion of imbalances from the imbalance settlement when they are associated with the introduction of ramping restrictions for the alleviation of deterministic frequency deviations pursuant to Article 137(4) of Regulation (EU) 2017/1485.

Extract from Swiss Grid Code:

2.6. Operational implementation of schedule changes and load controls

(1) The Operation Handbook of the UCTE / ENTSO-E (Policy 1) stipulates that schedule changes must take place in a linear fashion between control areas over a period of 10 minutes, beginning 5 minutes before the schedule change.

(2) To avoid unnecessary use of control power, the PPOs must adhere to the regulations described in point (1) when implementing their production schedules.

(3) To prevent excessive load variations, the DSOs must stagger the conscious connection and disconnection of loads (e.g. ripple control systems) in such a way as to produce an on balance roughly linear load change over a period of approximately 10 minutes, beginning 5 minutes before the schedule change.

(4) The requirements described in points (2) and (3) should be implemented on a user-pays basis according to a non-discriminatory and transparent procedure.

4.3 Solutions addressing the root cause of DFD

Several possible solutions can be implemented to mitigate the DFD issues on both a short or long term timescale. It is, however, important to distinguish solutions that address the root cause of DFD from a more general solution that aims to continuously enhance the frequency quality.

4.3.1 15 minute trading and 15 minutes ISP

Balance responsible parties have the obligation to balance themselves over the ISP. In principle, the shorter the ISP, the more closely the production will follow the load and the smaller the variation in term of power shift during schedule changes. The joint study of ENTSO-E and Eurelectric showed in 2011 that moving to a 15' ISP would significantly reduce DFDs compared to the current situation.

Today, ISPs are not harmonised in CE, where 15', 30' and 60' ISPs coexist. The Electricity Balancing Guideline imposes on TSOs, however, the requirement to adopt a 15' ISP by end 2020, with possible derogations until 1st January 2025.[1] Many TSOs in the CE synchronous system already apply the 15' ISP.

It is important to note that imposing a 15' ISP puts an obligation on the BRP to balance their portfolio over this (short) period but will result in an efficient balancing only if:

(i) **BRPs have the possibility to trade on the wholesale market products with the same granularity**. This is possible today on the OTC market, but only a few countries (Germany, Austria, Switzerland) have power exchanges offering 15' (or even 30') energy products. This situation will change in the near future (see below);

(ii) **BRPs adapt their behaviour in the desired way, according to the incentive signals they receive.** TSOs should monitor this and adequately incentivise BRPs to balance their portfolio through their local terms and conditions related to balancing.

Intraday market

ACER has recently taken a formal position interpreting the legal framework and urging TSOs to align on each border the MTU of the cross-border intraday market (XBID) with the longest of the ISPs of the TSOs of that border (e.g. between Belgium [ISP 15'] and France [ISP 30'], the intraday MTU should be 30').

TSOs participating in XBID are currently calculating by when they can apply this change, but about 20 TSOs (most of them in CE) have already implemented this rule or intend to do so by end 2020 at the latest. TSOs having a 30' ISP may be moving already from 1h cross-border trading to 30' cross-border trading, which will be an intermediate step towards the target market design.

This evolution should have a significant impact on the possibility for market parties to better balance themselves on a shorter ISP, which will also help reduce DFDs.

[1] Such derogation has been granted e.g. to France, which applies a 30' ISP.

Day-ahead market

The Article 8.2 of the clean energy package regulation on the internal market for electricity requires from nominated electricity market operators (NEMOs) that they facilitate the trading in time intervals at least as short as the imbalance settlement period both in day-ahead and intraday markets by 2021. Although given the flexibility provided by EB GL for derogating the implementation of ISP 15' until 1st January 2025, it is clear that at some point Single Day Ahead Coupling (SDAC) will also evolve towards a 15' resolution across CE.

This evolution of the day-ahead market may lead to a further reduction of DFDs. However, the additional benefits compared to the adoption of 15' products on the intraday market are not straightforward and the 2021 deadline seems very challenging for various reasons (performance of the single day-ahead coupling algorithm, appetite of market parties to trade 15' products in day-ahead, feasibility for TSOs to generate D2CF and DACF files with a 15' granularity, etc.). This evolution towards 15' trading in day-ahead seems therefore less of a priority than the adoption of a 15' ISP and a 15' energy product in the intraday timeframe.

Conclusion

The legal and regulatory framework will clearly require BRPs in CE to balance their portfolio over shorter periods in the coming few years and to introduce 15' cross-border trading products on the intraday market as of 2020 and at the latest by 2025 for countries having obtained a derogation. These combined measures should be considered the harmonised target solution to reduce DFDs.

If necessary, additional measures could be taken on an ad hoc basis, for example as an intermediary step in countries with a derogation from 15' ISP, or in countries with a production mix largely contributing to DFDs.

Merits:

- This solution must be implemented anyway, as it will be imposed by the CEP. A proposal could be to increase the priority of this and implement it earlier if possible.
- A higher granularity of the discrete schedule step will always reduce the deviation between the power ramping and the actual evolution of the load, if it is accompanied by a correct control of the frequency target parameters.
- Quarter-hourly products can partly solve the DFDs at its source, as it will split the hourly DFDs into quarter-hourly DFDs and with that the physical effect will be reduced. Thus, the DFD itself will be lower but will not be eliminated.

Impact on the Congestion Forecast Processes (IDCF, DACF):

It makes sense to firstly implement quarterly hour products for the ID trading in XBID. A next step could be to implement quarterly hour products in DA and D-2 processes, as this is likely to be more challenging. When the Cross Border Intra Day trading is available in 15 min products then it would also be possible to see the large differences between the individual quarterly hours in flows between the bidding zones. The flows can be significantly different from quarter to quarter hour during high ramp rates of load and/or RES production. In this situation, an Intraday Congestion Forecast (IDCF) process using quarterly hour resolution would need to be implemented. In the second phase, when the quarterly hour products are also implemented in DA and D-2 market coupling processes, a Day-ahead Congestion Forecast (DACF) process in quarterly hour resolution would be required.

4.3.2 Ramping on load and generation schedules

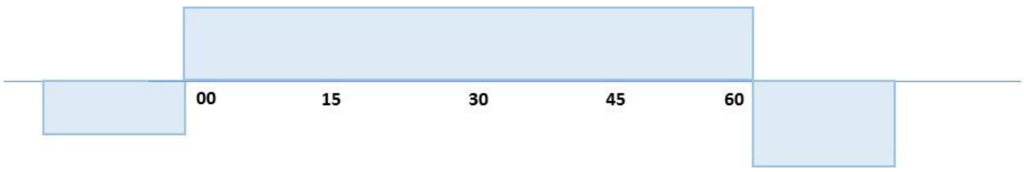
The idea of this solution is to incentivise the BRP to apply slower ramps on the physical output in a control area (generation and/or load schedules) which will reduce the size of DFD.

Ramping could be applied on generation schedules only or on both generation and load schedules.

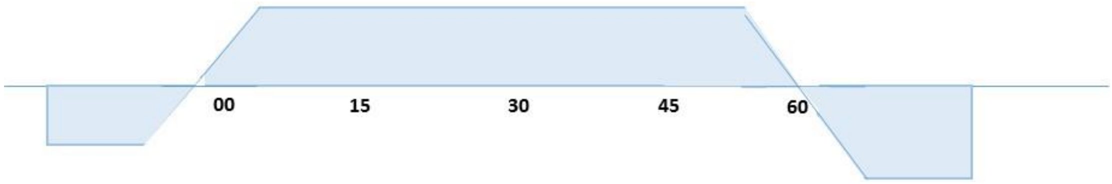
According to article 137(4) of SOGL, a ramping restriction can be applied to generating modules and/or demand units. Article 18(6)(l) of EBGL then requires imbalances to be excluded due to these ramping restrictions from the imbalance settlement.

The following text gives an explanation of the solutions with a simplified example.

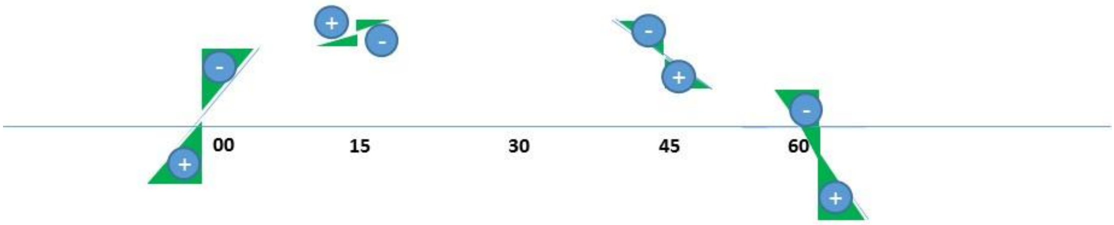
As explained previously, the BRPs are incentivised to avoid an imbalance through the ISP. In an hourly schedule market, for example, the incentive of the BRP in a system selling all its production on the wholesale market would be to follow this shape:



However, the change of the demand is naturally different from the shape of production of this BRP. For example, let us assume a load which has a ramp starting 5 minutes before the hour change, and finishing 5 minutes after (i.e. symmetrical ramping period of 10 minutes):



The difference between the schedules is the following:



The difference between the generation schedule and the demand schedule which occurs especially at the hour change is one of the main reasons for DFDs.

The proposal is to apply ramping periods to the BRP's production schedules and/or load schedules. One possibility would be to apply the ramping periods currently applied in inter-TSO XB schedules within CE (starting 5 min before and finishing 5 min after the start of each MTU)[2].

In accordance with article 18(6)(l) of EBGL, this implies redistributing the energy of generation and possibly load schedules in the previous/following period as follows:

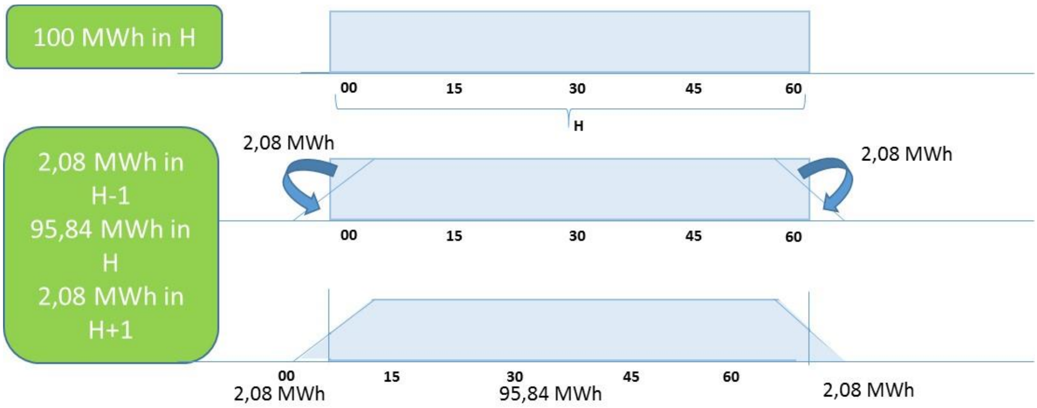


Fig. 16 – Impact of Ramping on schedules

This correction in the energy for the imbalance settlement (it could be implemented only in the imbalance settlement procedure or through an additional scheduling process to the BRP[3]) will allow BRPs to ramp their generation schedules closer to the variation of the load without being penalised. If the incentive to avoid step changes in production is sufficient (ideally production is actually ramped as required), this will help address the root cause of DFDs, as the instantaneous difference between the generation and the demand will be reduced.

This solution is currently applied in Switzerland (cf. section 4.1.3).

<u>Merits</u>*:*

- This solution reduces/minimises the instantaneous difference between generation and demand, thus attacking directly the source/root of DFD
- The solution is already foreseen as a possibility by SOGL and EBGL, but it is not simple, as is shown below.
- This solution affects the national schedules only (XB trades are not affected; current ramping constraints do not apply to XB trades), but the positive impact on DFDs will also be extended across borders.
- Even if the BRP does not apply exactly the shape in power, the gap between the schedules is expected to be smaller in any case than without applying ramps → the situation of DFDs will be improved. The effectiveness of this solution will, however, depend on the technical incentives for BRPs to follow the ramping constraints (e.g. to preserve the asset by applying slower ramps) and/or the penalties (if any) foreseen for not respecting the required

[2] The closer the ramping of generation and the ramping of the load, the smaller the DFDs. The closer the ramping of generation/load and the ramping applied on inter-TSO cross-border schedules, the smaller the FRCE of the TSO when energy is exported/imported.

[3] It would be at the discretion of each TSO how to implement the solution.

ramping constraints.

- Experience exists nowadays in some systems (e.g. Switzerland) with positive results.

Issues:

- Relevant impact on market models, in the definition of the internal schedules of the BRPs.
- Metering and monitoring of the power delivery to enforce penalties on deviations from required ramping, if applicable.
- In those systems which currently do not apply this, amendment of Terms & Conditions for BRPs and of LFC Block operational agreements, and regulatory approval.
- Requiring technical adaptation for both TSOs and BRPs (operations, IT).

4.3.3 Ramp restrictions on specific power plants and/or demand units

The mitigation measure is implemented on specific power plants and/or demand units, by enforcing maximum ramping limitations according to SOGL Article 137(4). These ramping limitations can be enforced without limiting the general ability of plants to offer their flexibilities to the market. This could be specifically relevant for Large Hydro power stations; in such cases limitation can be implemented by spreading the starting time (time delay). All individual measures are embedded in a coordinated approach also containing the behaviour of other very fast generation units, in order to achieve a steady generation change within the market area and with the intent to reduce the DFD. Any financial disadvantage for the individual market participant will be compensated according to the rules of EBGL Article 18(6)(l), hence this solution should not influence market behaviour but only the physical activation.

Ramping restriction can also be implemented as a rule under which the start or stop of a set of small production units can be spread over a time period which would allow a large instantaneous change in power to be avoided, causing a DFD.

The spreading of the start or stop of a set of small production units over a time period, which would allow a large instantaneous change in power to be avoided, is covered by art 137 of SOGL.

> *All TSOs of an LFC block shall have the right to determine in the LFC block operational agreement the following measures to support the fulfilment of the FRCE target parameter of the LFC block and to alleviate deterministic frequency deviations, taking into account the technological restrictions of power generating modules and demand units:*
> *(b) obligations on individual ramping starting times for power generating modules and/or demand units within the LFC block;*

In some countries, local legislation exists which gives an incentive to certain types of power plants to start or shut down at a specific moment in time. Such legislation could be a source of DFD and it would be good to consider whether legislation can be adapted to create a spread of the start and stop of units over a period of time of at least 10 minutes (+/- 5 minutes before and after the change of an hour, for instance).

Merits:

- Technically very efficient, as it tackles the main source of the frequency variations
- This solution would be very efficient against the very fast changes in hydro or wind output which currently exist in several countries. One example is the shutdown of wind at exactly 22:00 due to noise emission rules, which is one source for the large frequency deviations over 30 seconds observed at that time (see chapter 1.2)
- Due to the mechanism foreseen in Art. 18(6)(l), whereby the imbalances due to ramping restrictions shall not be considered in the imbalance settlement, the BRPs shall be compensated for the ramping. This means that there is no limitation to the offers on the market, but rather an adjustment of the physical injection in order to support system security.

Issues:

- It would leave less flexibility for the market participants as 4.4.2
- Needs to be compensated in the balancing mechanism as foreseen in art 18.6(l) of EBGL
- Requires technical adaptation including the enforcement monitoring of restrictions.
- Metering and monitoring of the power delivery to enforce penalties on deviations from required ramping, if applicable.
- In those systems which currently do not apply this, amendment of Terms & Conditions for BRPs and of LFC Block operational agreements, and regulatory approval.
- Requires technical adaptation for both TSOs and BRPs (operations, IT).

4.3.4 Limit net position changes between MTU

This solution consists of putting a limit on the change in net position allowed for a certain market area or market areas inside an LFC block.

As it has been established that changes in international schedules are partly causing the DFDs, limiting these changes could reduce the DFD.

This feature is included in most market algorithms, but rarely used inside CE.

The euphemia algorithm description for the SDAC states the following:

4.1.1. Net position ramping (hourly and daily)

The algorithm supports the limitation on the variations of the net position from one hour to the next. There are two ramping requirements on the net position.

- Hourly net position ramping: this is a limit on the variation of the net position of a bidding area from each hour to the next.

- Daily (or cumulative) net position ramping: this is a limit on the amount of reserve capacity used during the day.

It is, however, common practice on the interconnections between CE and Scandinavia, where each HVDC line has such a limitation applied.

The following borders already have those constraints active:

bidding zone FROM	bidding zone TO
Estonia	Finland
Netherlands	Norway 2
Denmark 1 internal	Norway 2
Denmark 1	Denmark 2
Poland Internal	Sweden 4
Lithuania	Sweden 4
Denmark 1 internal	Sweden 3
Lithuania	Poland Internal
Sweden 4	Germany
Denmark 2	Germany
Great Britain (EPEX)	Republic Of Ireland
Great Britain (EPEX)	Northern Ireland.

Issues:

- This is a highly market-impacting measure which should not be taken lightly and will require extensive justification to market parties and regulators.
- The task force recommends that this measure should only be taken by an LFC block if no other measures are reasonably available or are sufficient to control its contribution to the DFDs
- Be aware that sometimes large changes in solar or wind output might justify or even require large changes in the international schedule, and this measure might prohibit this and thus create a new problem for the LFC block.

4.3.5 Balancing products on a 15 minute basis.

The introduction of 15 minutes products in balancing, for example through the implementation of the mFRR platform (MARI project), could also be a measure for some LFC blocks to help reduce DFDs (allowing the demand to be approached with generation schedules coming from the activation of balancing energy of BSPs with a 15 minute resolution).

The applicability and usefulness of this measure depends on the way each LFC block performs balancing.

4.4 General solutions to improve the frequency quality

This section covers possible solutions that aim to improve frequency quality in general, this therefore does not target specifically the DFD that occurs during schedule changes. Such solutions can be technically very effective as they aim to contain any frequency deviations and therefore limit DFD occurrence and impact. Nonetheless, relying exclusively on such mitigation could result in further deterioration, as the root cause of the problem is not properly addressed.

4.4.1 Additional FCR

Additional FCR reserves can be utilised to contain frequency deviations and mitigate risks of excursions, the reserves to be procured would be higher than the dimensioning incident (3000 MW) using a probabilistic approach. Determination of the Ci factor contribution can be done using the existing methodology.

Based on rough estimations and considering a network power/frequency characteristic of around 27000 MW/Hz, the FCR increase is expected to be around 5400 MW.

This FCR requirement increase would lead to an increase of the network power/frequency characteristic but not in a proportional way, because procured FCR contribution is only a part of the overall power/frequency response. Therefore, the target for DFD reduction might not be reached. Furthermore, it is not certain that the system has this additional margin available and that there is enough liquidity on the market for this FCR.

An alternative solution resulting in a lower required FCR increase (around 2000 MW) could consist of a specific new product with a full activation at 75 mHz but this would most likely require even more complex implementation and would need more time and effort to put it in place.

The additional volume which would reduce DFD to the set targets would be around 2000 MW on top of the existing 3000 MW for the whole CE synchronous area.

Any LFC Block which chooses this as a solution will need to increase its FCR obligation (prescriptions and procurement) by 66% at least during the time period when DFDs occur, and will in such a way assist in reducing the DFD with the additional FCR provided.

The additional FCR would only be needed during the usual time periods when DFD occur, making the additional FCR a specific product which could be cheaper.

<u>Merits:</u>

- Technically efficient, does not require the definition of a new product or specific operational implementation.

<u>Issues:</u>

- Will not solve the root issue of DFDs; will only reduce the physical effect.
- The solution is considered expensive and difficult to justify economically.

- The introduction of new suppliers of FCR (e.g. battery providers, electric vehicles, aggregators…) could in the future make this a more economical way forward.
- It could be that not enough FCR offers are available in some countries
- Having two different FCR services (0-75 mHz and 0-200 mHz) is not considered a quick-win solution
- Increasing FCR should reduce DFD but the actual impact is not known and not easily foreseen
- Increasing the FCR requirement for CE will not lead to a proportional increase of K
- Properly sharing FCR within TSOs to maximise the K increase
- TSOs expect Regulatory changes/NRAs approvals to increase FCR
- TSOs expect Regulatory changes/NRAs approvals to introduce 'new' FCR (0-75 mHz)
- Market Frameworks and IT developments may be necessary to implement the proposed solutions (e.g. market design, new products, new bidding processes)
- SAFA need to be amended and approved by all NRAs
- TSOs expect changes to their IT infrastructures
- Technical changes to generating units controllers are expected (e.g. droop changes, two different FCRs)
- Regulatory/Market changes may require mid/long-term timings
- IT developments may require mid-term timings
- 'Asynchronous' implementations by TSOs → Cost compensations

<u>Timeline:</u>

- Relatively short compared to the creation of a new product.

4.4.2 Faster acting Reserves

Provide a new product which reacts immediately on fast frequency changes at the change of the MTU.

For instance, batteries would be able to provide very quickly reserves which would stop the frequency going down.

In addition, the product is only needed for a short period before and after the change of the MTU (currently mostly at the change of the hour), meaning it does not require a huge energy storage (a storage of 5 minutes would probably be sufficient)

<u>Merits:</u>

- The fast reaction of batteries would allow less use of the (slower) FCR and a faster way to stop the frequency from deviating too far from 50 hertz.

<u>Issues:</u>

- New products will need to be developed, but there is a willingness (in MC) to consider this development, which would need to be followed by WG Ancillary Services

- The solution is expensive, although probably less expensive than additional FCR.

Timeline:

- Relatively long as it requires the creation of a new product.

4.4.3 Additional aFRR

Increasing aFRRs to act on the imbalance volume deviation during schedule changes.

Merits:

- Already analysed in previous investigations on DFD mitigation measures [1] [3], the effect is minimal, even for large volume.
- aFRR is able to manage DFD with relatively slow variation.

Issues:

- Expensive and economically difficult to justify.
- The increase in term of reserves among control blocks can be difficult to define (not as transparent as FCR); this would require NRA validation.
- Simulations show that aFRR is too slow to solve the DFDs with high RoCoF.

Timeline:

- Relatively short compared to the creation of a new product.

4.4.4 Use of higher K factor in AGC

Increasing the K factor in the automatic FRCE controllers of the control areas will incite the aFRR to activate in the same direction as the FCR (so increasing the volume of FCR) during frequency deviations.

However, doing so will create only an additional source of ‘false’ control, as the FCR contribution of the LFC block will not change. The K factor and FCR should correlate for one control block as close as possible.

Given the speed of aFRR, for DFD with a RoCoF above 1 mH / sec, the aFRR is too slow to react and cannot limit the change in frequency. It will, however, reduce the frequency change before the DFD and thus could even lead to increasing the maximal frequency deviation.

Sufficient simulations need to be performed to check if increasing the K-factor reduces the DFD also for the highest RoCoF values (up to 5 mHz / sec) before such a change can be accepted.

Nevertheless, the K factor used in AGC should be as close as possible to the ‘real K factor’ of the control block. Therefore, it is better to use an estimation of the real time K factor instead of the theoretical K factor which is calculated only once a year by SG SF. The value of SG SF should be understood as the minimum value to use in AGC (to be corrected by the results of FCR cooperation).

4.4.5 Mutual frequency assistance between synchronous areas

Frequency Coupling between synchronous areas as mutual exchange will increase FCR response in all synchronous areas (SAs) without lowering the procured FCR capacity.

The paper [12] presents more details on frequency coupling and its limits.

The frequency coupling process is one agreed between all TSOs of two or more synchronous areas involved and allows linking the activation of FCR by an adaptation of HVDC flows between the synchronous areas.

Currently, there are several HVDC interconnectors providing frequency coupling services. The characteristics of these services are quite varied and do need to comply with SOGL.

Three technical classes of frequency coupling have been defined, namely FCR exchange, frequency netting and frequency optimisation. These are different services, and specific limits for the implementation and clarification of the existing definitions (FCR versus frequency coupling) from SOGL are proposed in the framework [12].

FCR exchange should not affect the dimensioning needs of FCR for the providing SA, as defined in SOGL article 173(3). Hence, to facilitate FCR capacity exchange, additional physical FCR provision in the providing SA is necessary.

It is concluded that frequency netting and frequency optimisation are mutual SA-SA support services that could affect the FCR dimensioning needs in the receiving and/or delivering SAs by improving the frequency quality by design. The gains in frequency quality can result in benefits associated with FCR volume reduction via the concept of sharing, as defined in SOGL. Indeed, whereas FCR sharing within a SA is not allowed, it is allowed between SAs. However, for this to be possible, preconditions must be satisfied: an all TSO-agreement within a SA would be required as would transparency regarding the amount of the remaining final FCR available after sharing.

<u>Merits:</u>

- No consumer will feel any changes
- Increased K-value, lower frequency deviations

<u>Issues:</u>

- Operational Limits on ENTSO-e Frequency Coupling have been identified in 2017 [12].
- SAFA has limited the use of this function, which could need to be re-evaluated.
- NRA validation will be needed

<u>Timeline:</u>

- Several months would also depend on the concerned TSOs

4.5 Solutions which are under investigation

The following possible solutions require further investigation to analyse the feasibility and efficiency but are already given for completeness, as they have been proposed by one or more LFC blocks.

4.5.1 Introduction of Spot Power Balancing

The introduction of Spot Power Balancing (also known as residual central dispatch) could also be a way to reduce large DFDs. Spot Power Balancing takes place after in day gate closure i.e. the market meets the settlement period energy requirements and residual central dispatch is used to meet spot power requirements within the settlement period.

Normally active power and demand will be balanced so there will be no large mismatches. There may be some, as it is impossible to estimate the demand correctly all the time but this method will remove large mismatches. There may also be active power failure which may also lead to smaller frequency deviations for a short time.

Market mechanisms may be used to alter the active power so it matches the demand second by second.

Issues:

- this will be a major change politically in many control blocks in CE.

4.5.2 Use changes between ISP for BRPs as market based aFRR.

DA-result (Bilateral and stock-market) gives a change in MWh/h from one ISP to the next for each LFC-area. DA stock market gives a price difference between these two ISP in each price area.

The idea is to avoid a sudden change in production at the ISP shift time, which is caused by the ramping of (most) consumption, with the purpose of promoting load to be followed.

By converting the change in MWh/h position and the change in DA price between the two ISP to additional aFRR-bids with the bids covering the last half of the first ISP and the first half of the last ISP this will lead to:

- No sudden change at ISP change time (DFD eliminated) – voluntary participation will not be enough to get a level playing field for all types of production.
- The LFCs will activate the necessary capacity to follow the change in consumption (will cause a small frequency deviation due to the delay between LFC-input and aFRR response)
- If consumption rises faster than a straight ramp, the additional aFRR capacity can be activated as needed.
- Only in the event the ISP in its totality (over all BRPs) is short or long will the traditional aFRR be activated.

4.5.3 Dynamic Frequency Setpoint

As the DFD is very consistent, it is possible to mitigate very high frequency deviations and peaks by giving all LFCs a frequency set point that goes in the opposite direction as the expected frequency deviation.

This solution has another benefit, as it can also reduce the effect of long lasting imbalances.

SG SF has had this on their agenda for years, and asked Erlangen University to perform a study on it, with the following conclusion:

From the simulation results it can be concluded that the model proves a significant frequency quality improvement to deal with the deterministic frequency deviation by the use of a DFSP in the secondary controllers.

4.6 Impact study of the proposed solutions – full model

Several models were tested to analyse the impact of the different proposed solutions on the DFD. This chapter gives the results of these solutions, which provide an indication of the impact to be expected from each solution.

4.6.1 Simulation model used

The model, which was used to simulate several solutions, is based on MatLab SimuLink and was built by TenneT Germany on behalf of the ENTSO-E SG SF. The idea was to have one model covering all Load-Frequency-Controller of the CE Synchronous Area to simulate different cases, which were or will be discussed in ENTSO-E. This model can also be used to simulate the effect of future developments such as MARI, PICASSO or TERRE.

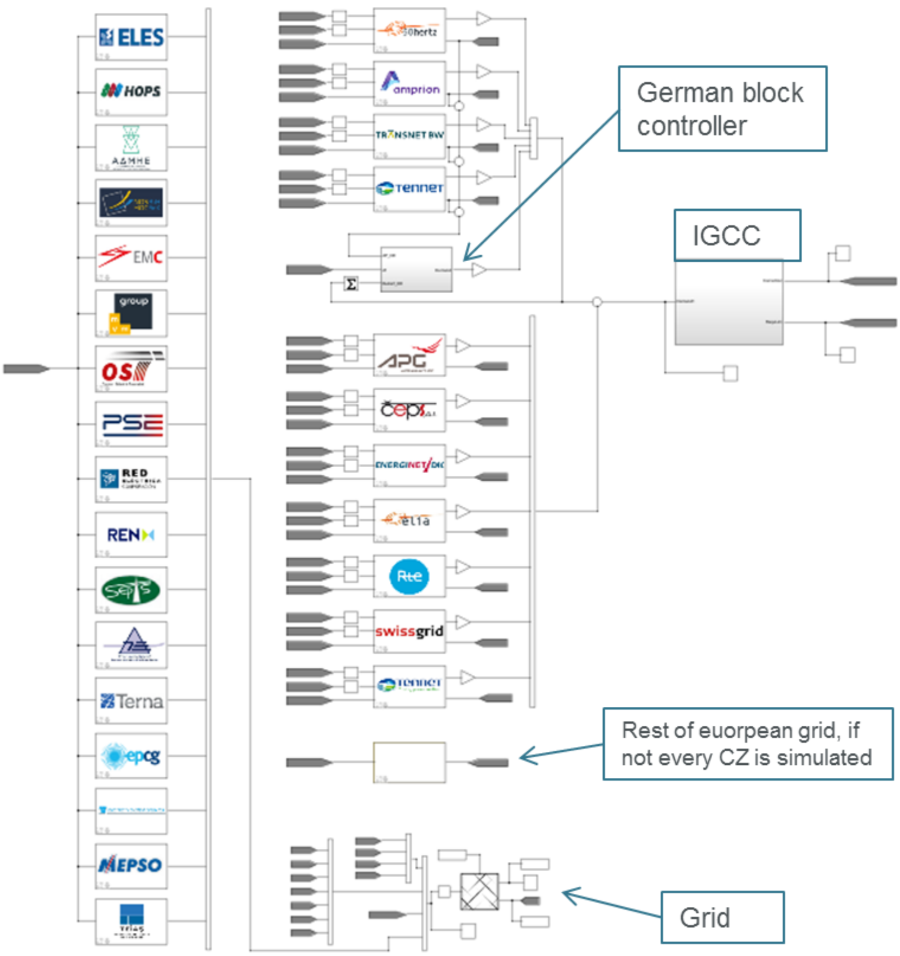


Fig. 17 – LFC-Model CE

The model is based on a development in Germany and consists of several blocks. One block covers the German LFC-Block and connected to that is the block on IGCC, which consists of all IGCC-Partners. Another block covers all currently non-IGCC-TSOs. The last block describes the 'grid'. This block depends on the consideration of LFC-Blocks in the simulations. Simulations can be done for single LFC-Areas up to the whole synchronous area. Depending on the simulation, the 'grid' consists of all those LFC-Areas not considered.

The model consists of individual blocks per TSO, whereby each TSO has its own Load-Frequency controller. As not all information and every LFC-setting is public, a standard PI-controller with Anti-Windup was used and adjusted by individual LFC-parameters, as:

- proportional factor,
- time constant,
- type of aFRR activation (MOL-based or pro-rata) and
- full activation time of aFRR.

The LFC-Parameters are based on a Survey by SG SF from 2018. For data that have not been delivered within the survey, the parameters from an ENTSO-E Study 'Impact of Merit Order activation of automatic Frequency Restoration Reserves and harmonised Full Activation Times' were used.

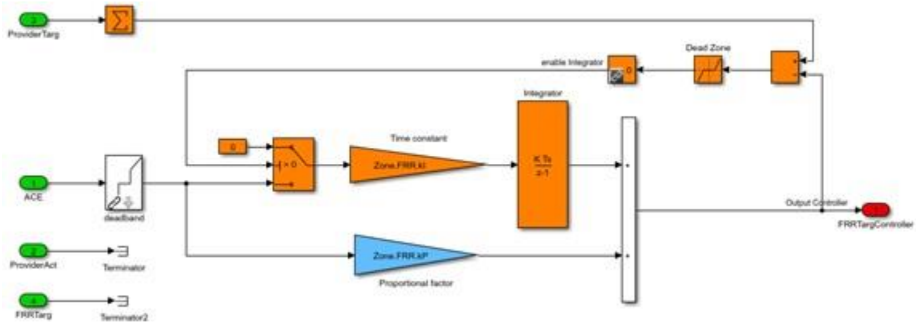


Fig. 18 - Standard PI-controller with Anti-Windup

To be realistic in the results of the model, it also considers the type of aFRR activation as well as some assumptions regarding the behaviour of aFRR activation. Within the model, it is possible to choose between the following settings for aFRR behaviour:

- slow PT 1
- fast PT 1 or
- ramp

Ramp means a static ramp over the full activation time, whereby the gradient is calculated based on the requested volume divided by the full activation time.

In addition to the individual LFCs, the current set-up of the IGCC is also considered. That means that the simulation model also simulates the netting of imbalances between all current IGCC partners. If one TSO has a negative imbalance and another a positive imbalance, the model also takes netted imbalance into account in the further calculations. As only frequency is simulated in that study and we assume that all have a deviation in the same direction, netting will not have any impact on the results.

The following figure shows how load interacts with the frequency. The frequency within the model is described by an integrator. The inequality of power is divided by a constant load of 422,728 MW and a time constant of 12 s. For the simulations in that study, dP is calculated as the deviation between load and generation.

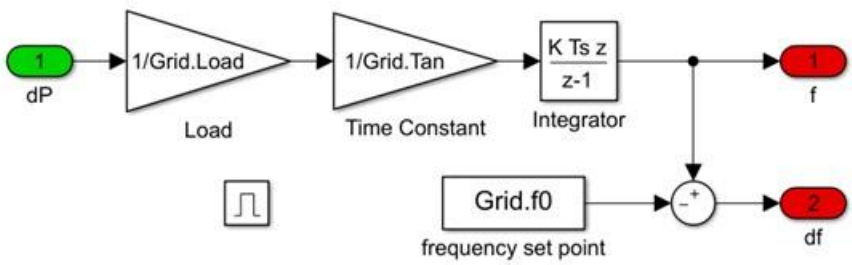


Fig. 19 – Frequency

Due to the assumptions made, the model is limited in its results compared to the reality. The following assumptions will have an impact on the results:

- self-regulation effect of load: is assumed as a constant value based on the formula from SG SF:

$$\lambda_{Self\ Regulation} = \frac{1\%}{Hz} \times 439.127 GW = 4391{,}27\ MW/Hz$$

- FCR delivery: The FCR delivery is calculated based on the k-value only. As we know that, for example, France usually provides more FCR than their initial obligation, this additional FCR is not considered in the model.
- constant k: As we know, the k-value varies in some LFC-blocks over the day. The model assumes a constant k-value for the whole day.
- aFRR: The total amount of aFRR per LFC-block is currently not known, therefore each LFC-Block is simulated with only 200 MW of aFRR. An inclusion of the total amount aFRR per LFC-Block would increase the quality of the results.
- aFRR activation behaviour: Some assumptions have been made to simulate the effect of aFRR activation. As these assumptions do not perfectly fit the reality, the assumed aFRR behaviour will have an impact on the simulation results. The results can be increased when a normalised aFRR behaviour is included in the model.
- timely resolution of input data: the quality of the results are depending on the data used for simulation. As data of generation and load for whole CE is only available in 15 min resolution A continuous course of load can only be calculated by interpolation between every 15 min value. The same counts for feed-in of renewables.
- ramping of generation and load: Some assumptions have been made for the ramping behaviour of different generation types. An overview can be found in the following table:

Name	Generation types	Ramping time before and after (quarter-) hourly change
Very fast	HydroPumpedStorage, HydroWaterReservoir	30 sec before, 30 sec after
fast	Biomass, FossilGas, FossilOil, HydroRun	2 min before, 3 min after
slow	FossilBrownCoal, FossilCoal, FossilHardCoal, FossilOilShale, FossilPeat, Geothermal, Nuclear, Other, OtherRenewable, Waste	5 min before, 5 min after
continous	Marine, Solar, WindOffshore, WindOnshore	7.5 min before, 7.5 min after or 30 min before, 30min after

The ENTSO-E Transparency platform was the source of the data for generation and load, which were used for the simulations for this report. These schedules were the main input for the model to simulate the effects of proposed solutions.

To compare the results with the reality, we have chosen 4 April 2019 as a day which was special in terms of height of frequency deviation, but without any further special situation, such as on 10 January. The 4 April was characterised by several DFDs over the day. At 21:00, the minimum frequency of the day reached 49.89 Hz. The maximum frequency that day was 07:00, with a value of 50.08 Hz.

The following figure shows the day as a result of the simulation model. This figure was the base case for all other simulations. The effects of the individual simulations were always compared to that base case. For that comparison, the following statistical parameters have been used:

- mean value,
- standard deviation,
- minimum,
- maximum and
- variation

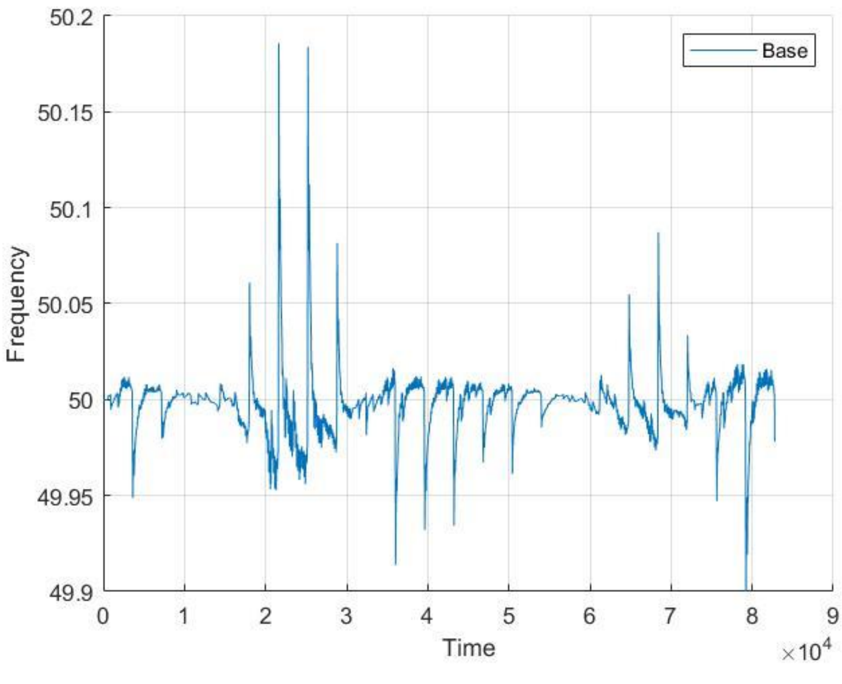


Fig. 20 – 4 April – simulated by the model

The following figure shows 4 April with real data. We can see the difference between reality and simulation by comparing figures 20 and 21. An explanation of why the model is more sensitive, especially in the frequency peaks, was given above. However, the mean frequency peaks can be seen in the real data as well as in the simulation, even though the height of deviation deviates.

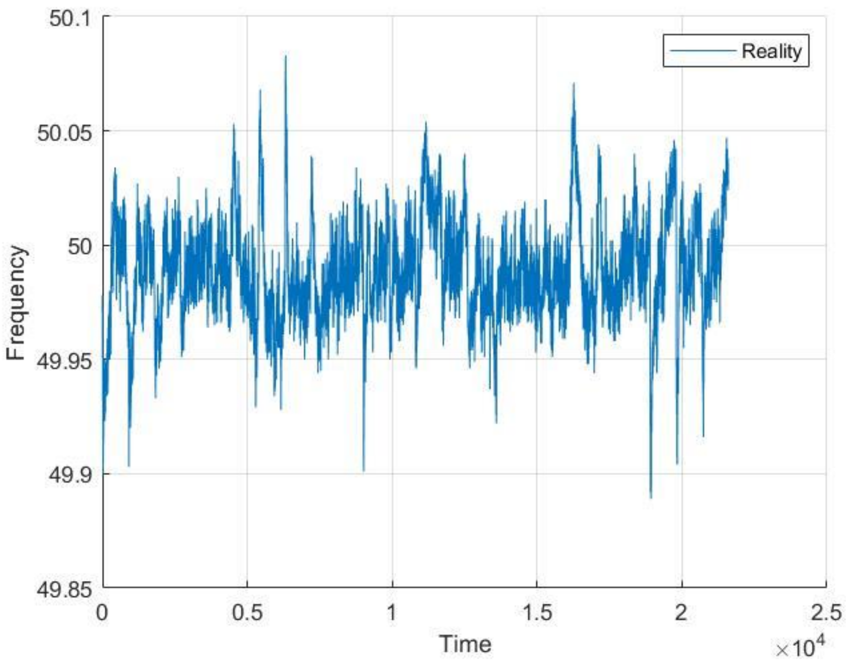


Fig. 21 – 4 April – real data

4.6.2 Ramping on load and/or generation schedules

As described above, the model considers different ramping rates per generation type. To simulate the effect of ramping on generation schedules, each generation type received the same ramping rate as all the others. For example: Wind was assumed with a continuous ramp to simulate the base case. For the simulation case 'all generation jumps[4]' it was assumed that wind generation ramps between 30 sec before until 30 sec after the shift of MTU.

Based on that principal, the following cases were analysed:

- All jumps: mean that all generation type ramps 30 sec before till 30 sec after the MTU.
- All fast: mean that all generation types ramp between 2 min before till 3 min after MTU.
- All slow: mean that all generation types ramp between 5 min before till 5 min after MTU.
- All continuous: mean that all generation types ramp between 7.5 min before till 7.5 min after MTU.

In the following are figures for each of the cases in comparison to the base case.

[4] The term "jump" is used here to represent very fast, almost instantaneous, variation of power output

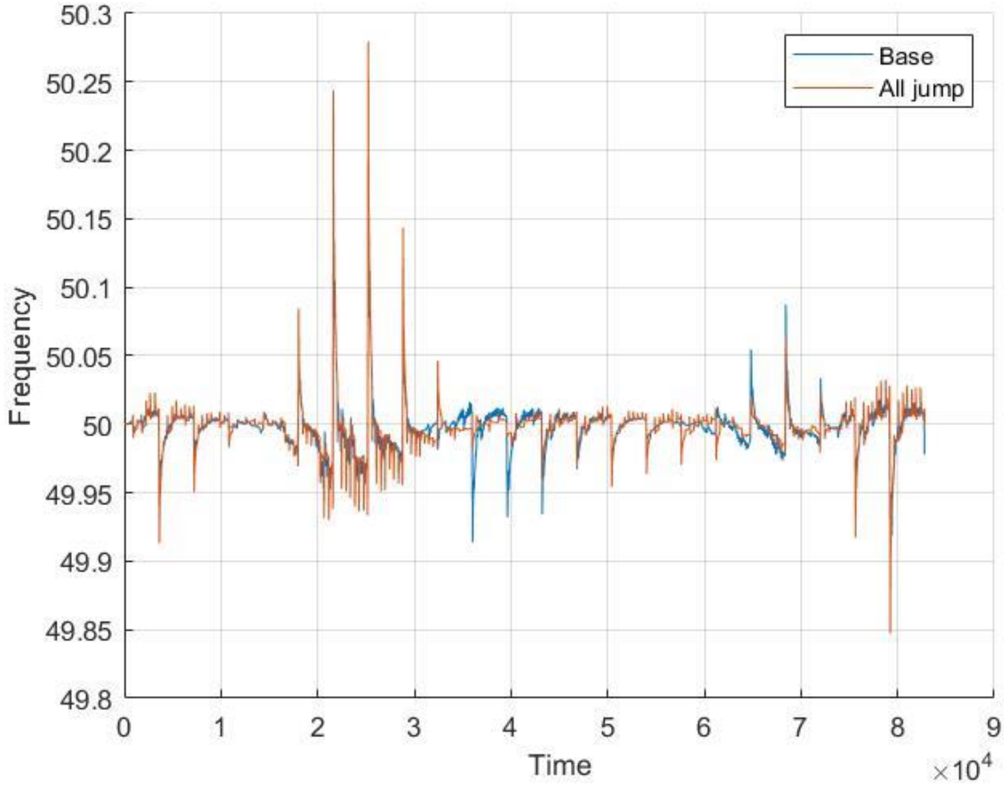


Fig. 22 – All generation ramps between 30 sec before till 30 sec after MTU

Based on the figure, it is clear that the frequency will be worse than in the base case. In particular, the peaks in the morning and evening hours are much higher. The following table gives an overview of the statistical comparison.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All jump	49.9982	0.0168	49.8475	50.2794	2.8108E-04

The following figure is a zoom into the highest frequency peak in the morning hours to give an impression of the ramping rate and also to observe the difference between the base case and simulated case in more detail.

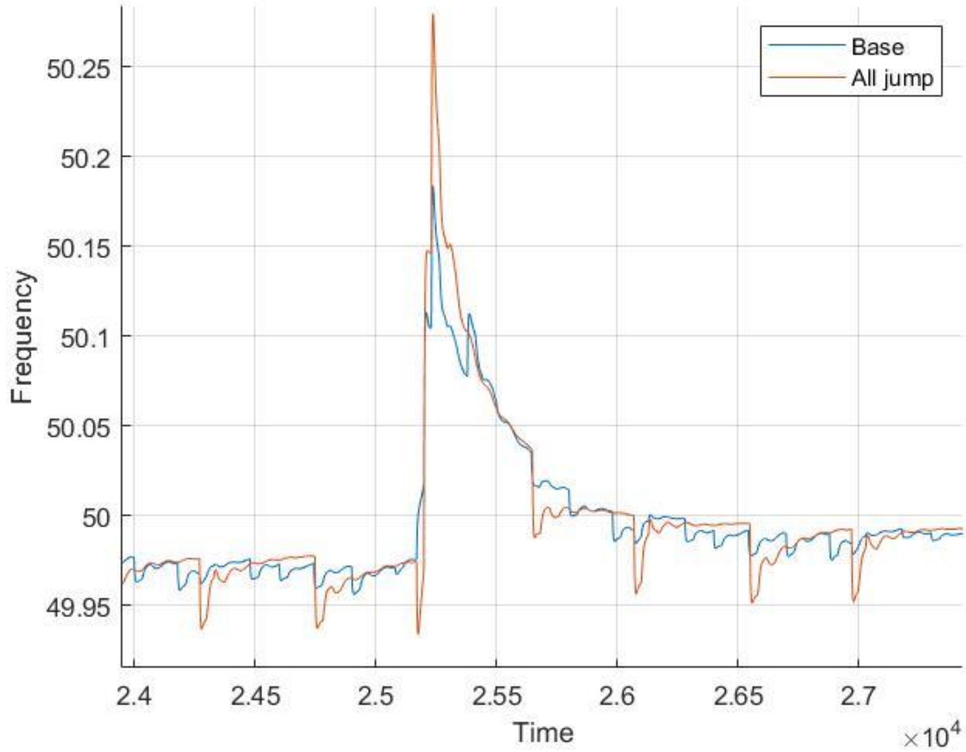


Fig. 23 – All jump - zoom in

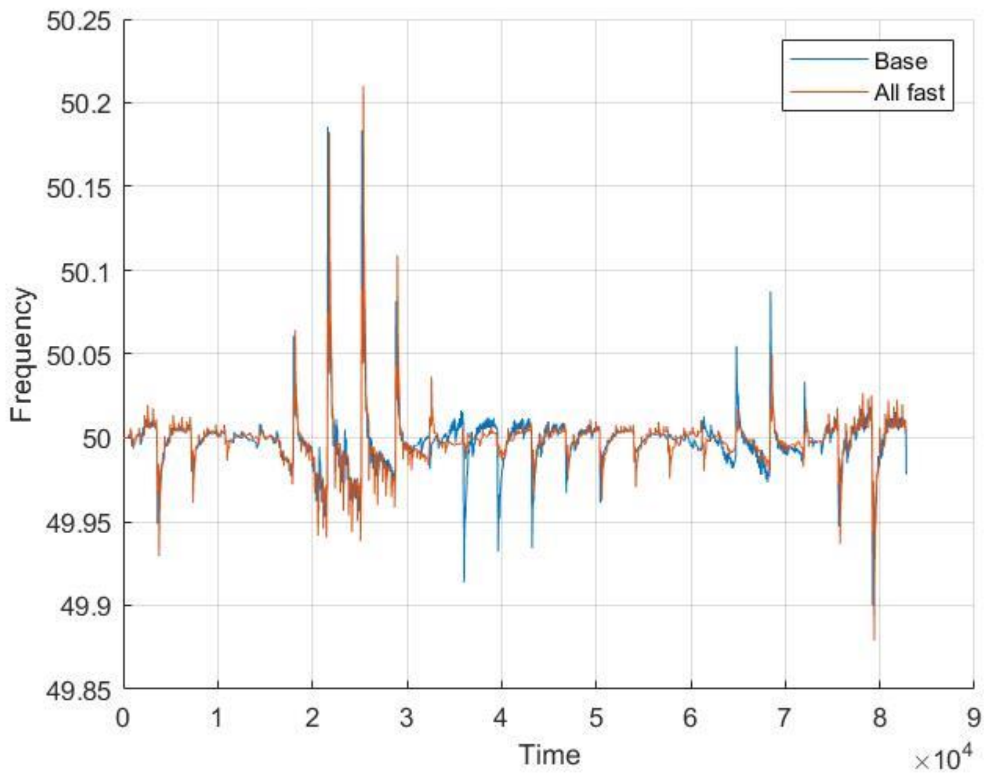


Fig. 24 – All generation ramps between 2 min before until 3 min after MTU

Based on the figure, you can also see that a fast ramping of all generation will make the frequency worse. The frequency quality is slightly better than in the case of 'All jump', but it is still out of operational range.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All fast	49.9983	0.0145	49.8791	50.2101	2.1003E-04

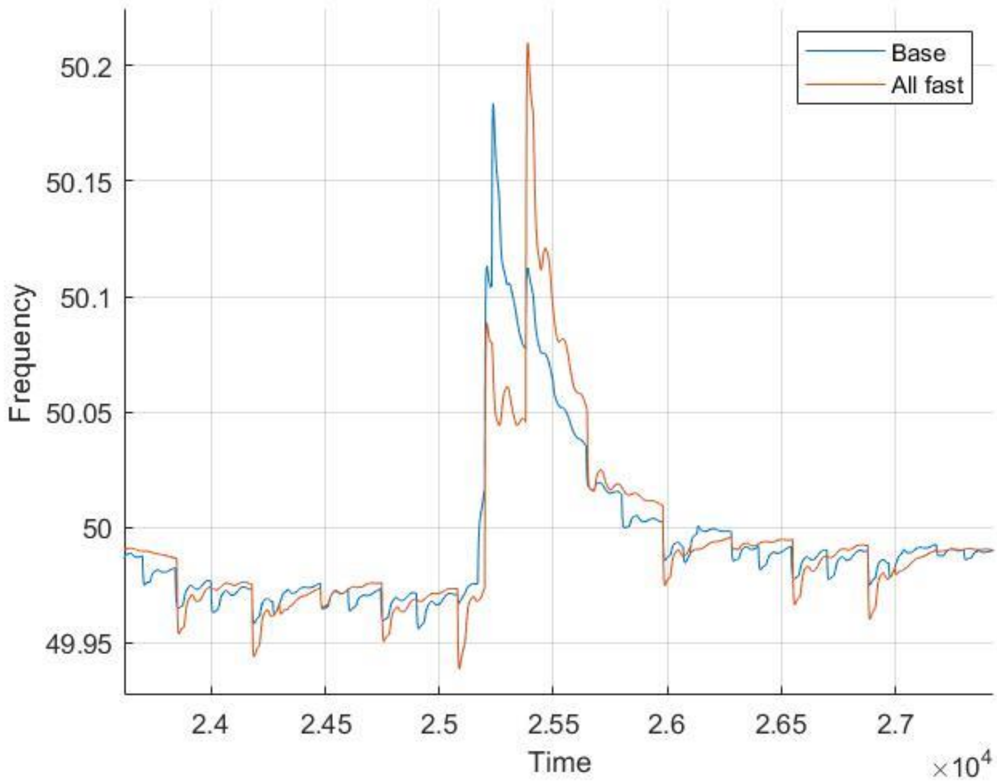


Fig. 25 – All fast – zoom in

As we can see in the figure above, due to the change in ramping, it comes also to a shift in the time of the frequency peak. Whereas in the case of 'all jump' the frequency peak is at the same time as in the base case, we can now observe that it is later than in the base case. This leads to the conclusion that a huge part of the overall generation, especially in the base case, comes from very fast reacting units.

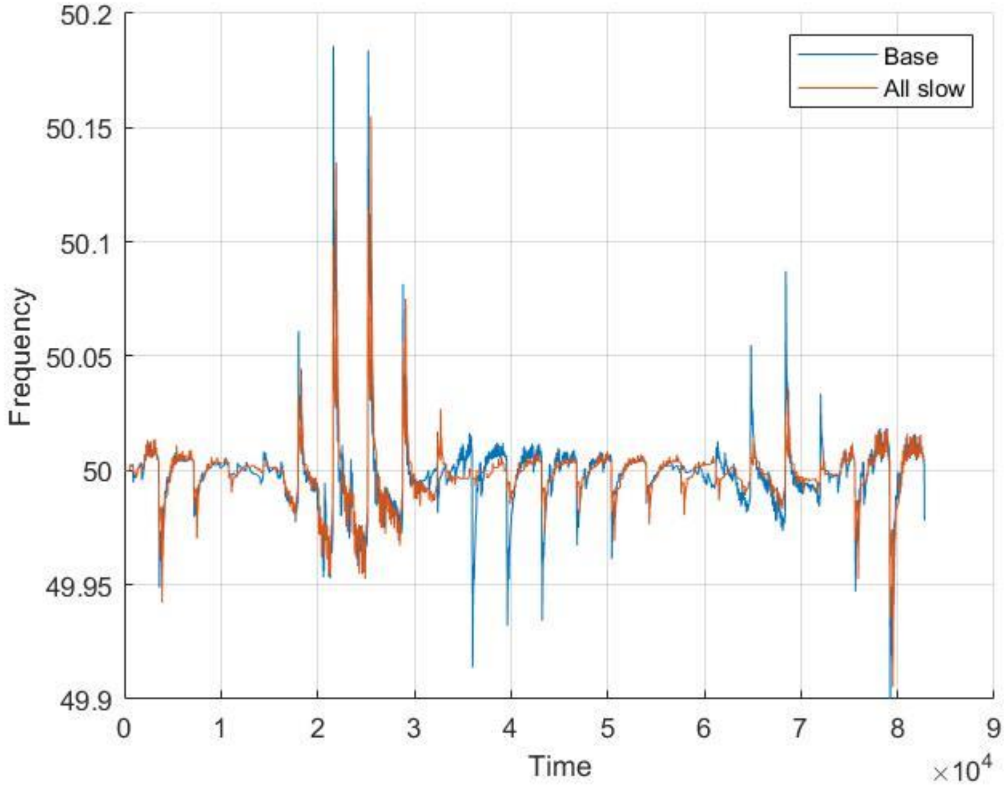


Fig. 26 – All generation ramps between 5 min before until 5 min after

Based on figure 26, we can see that the slower ramp rate for all generation units increases the frequency quality. The frequency becomes smaller than in the base case. However, the frequency deviation is higher than 100 mHz in overfrequency and slightly lower than 100 mHz in underfrequency. This can also be seen in the following table and in the following figure.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All slow	49.9985	0.0127	49.9053	50.1550	1.6129E-04

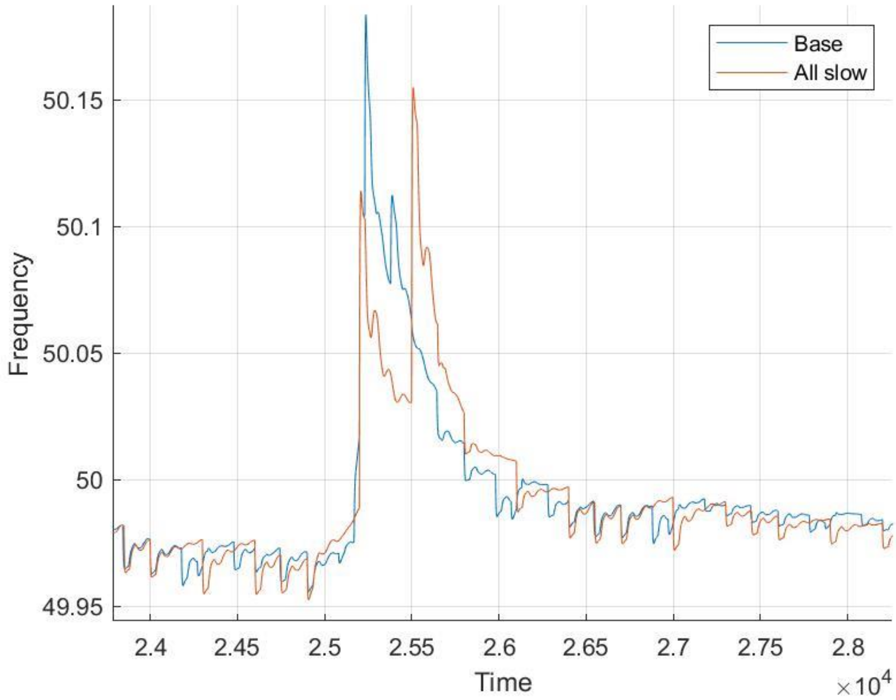


Fig. 27 – All slow – zoom in

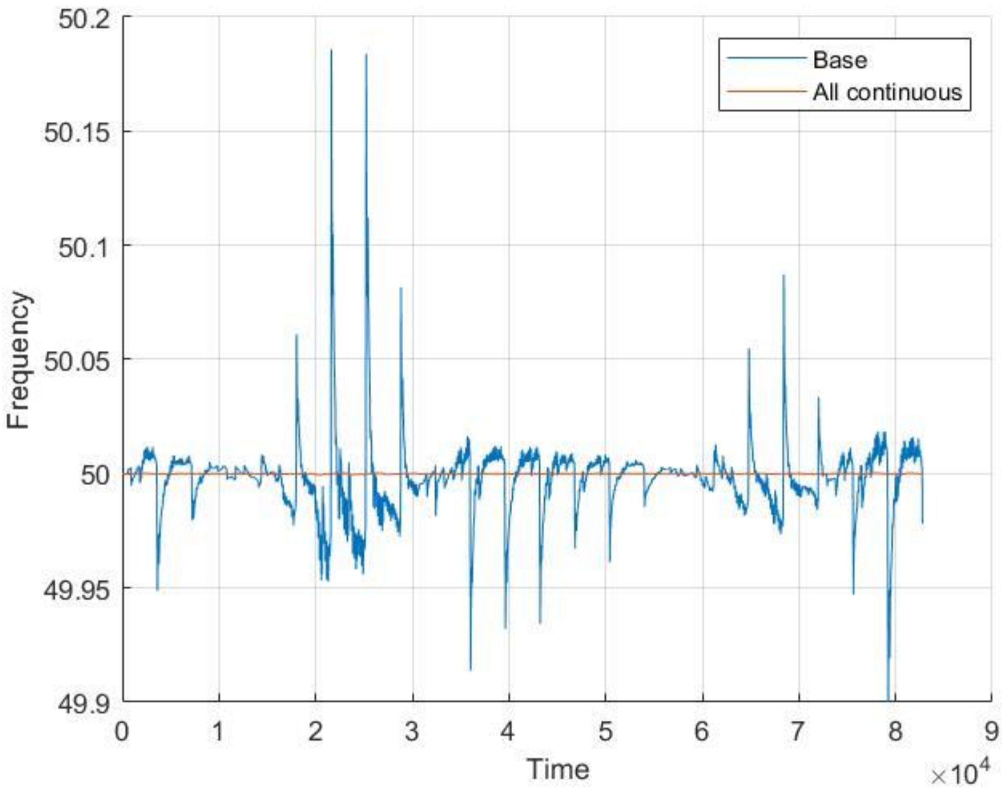


Fig. 28 – All generation ramps continuously between 7.5 min before till 7.5 min after MTU

Based on figure 28, we can see the effect of an extreme scenario whereby every generation is load following. In this case, there would not be any huge frequency deviation. There are only slight deviations from 50 Hz, as we can also observe in the following figure and table.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
All slow	49.9985	0.0127	49.9053	50.1550	1.6129E-04

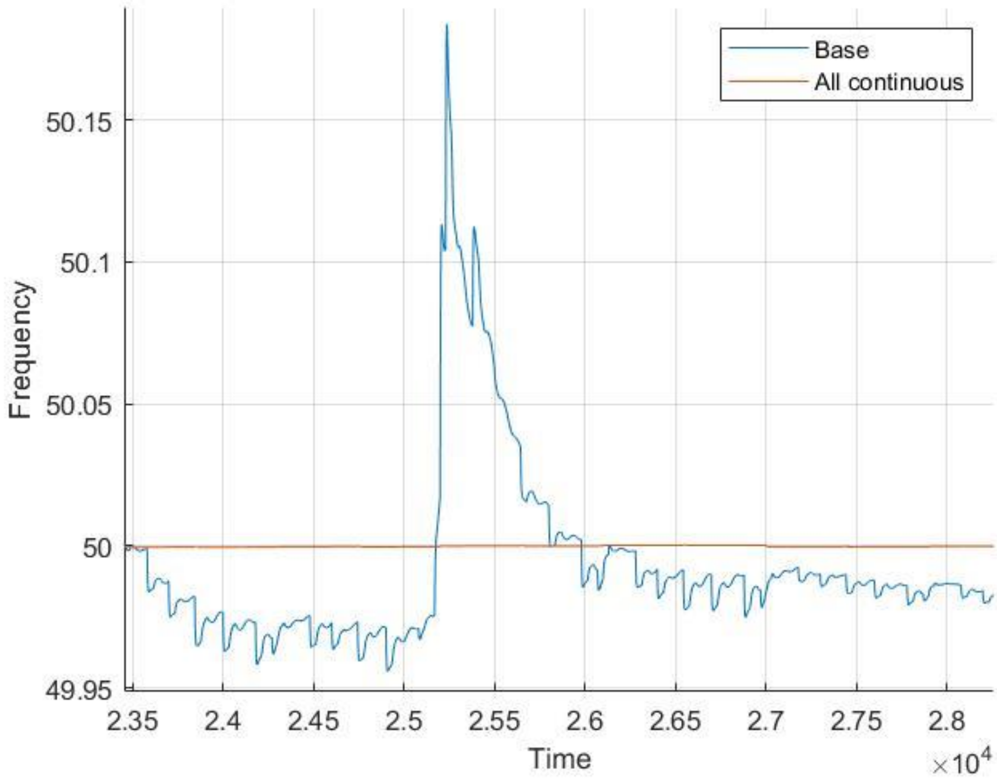


Fig. 29 – All continuous – zoom in

4.6.3 Ramp restrictions on specific units

In opposition to the simulations for ramping on generation schedules where ramping of all generation types were changed, in these simulation cases, only specific generation types have been changed in their ramping behaviour. The ramping behaviour of wind generation and water power plants have been changed, as they are usually under suspicion when discussing DFDs. All other generation types have the same ramping behaviour as they have in the base case.

Wind was assumed with a continuous ramp to simulate the base case. For the simulation case ‘wind jumps’, wind generation ramps were assumed between 30 sec before until 30 sec after the shift of MTU. The following figure provides an overview of the result.

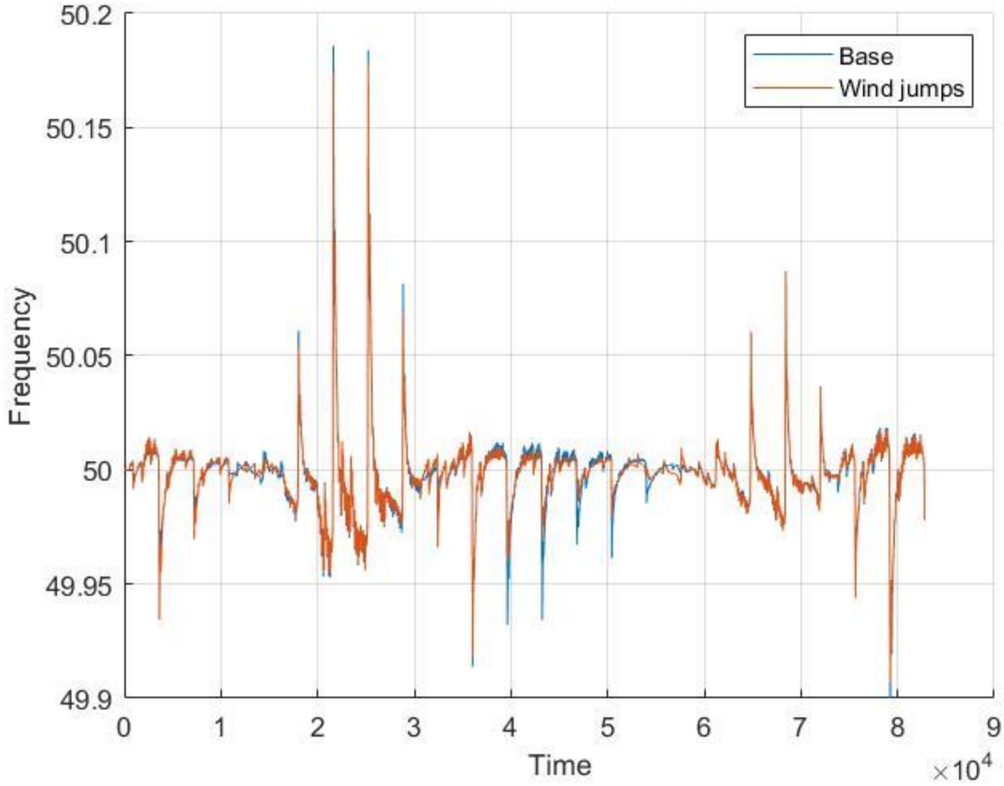


Fig. 30 – Wind jumps – ramping 30 sec before until 30 sec after the MTU

Based on the figure, we can observe an increase in frequency quality, but it is still in the range of the base case. This leads to the conclusion that wind generation compared to the total sum of generation has a small impact on frequency behaviour. This can also be seen in the following figure, where we can observe almost no difference between the base case and the simulation.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Wind jumps	49.9983	0.0146	49.9068	50.1783	2.1250E-04

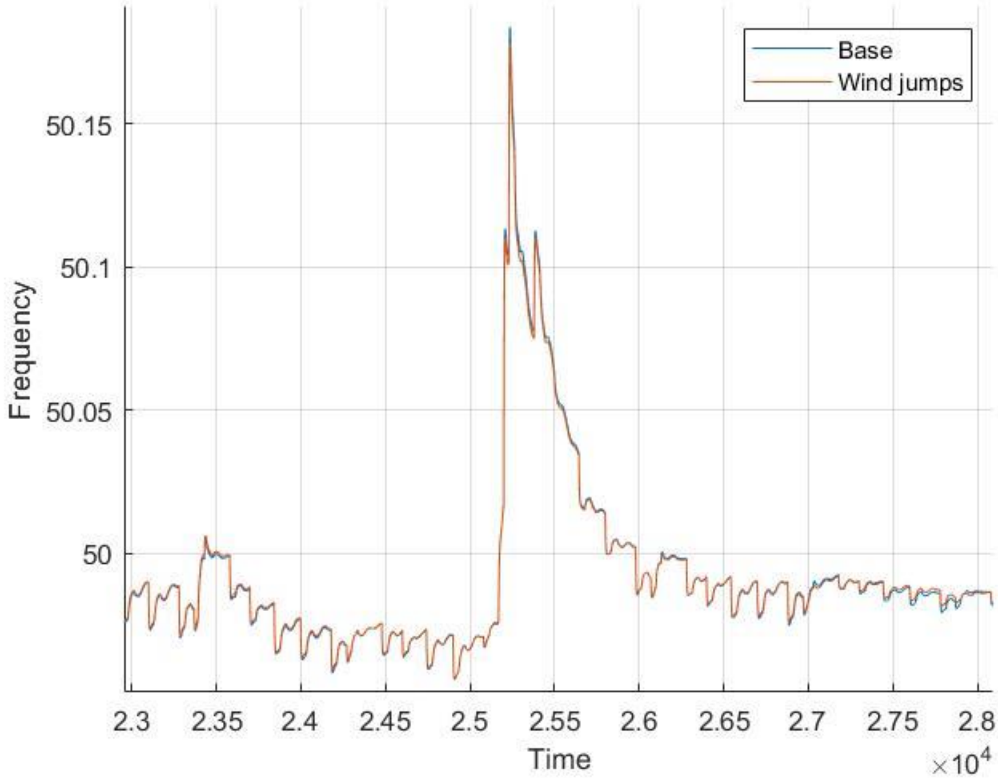


Fig. 31 – Wind jumps – zoom in

Water was assumed with a very fast ramp between 30 sec before until 30 sec after the shift of MTU for the simulation of the base case. This ramping behaviour was changed to slow, 5 min before until 5 min after MTU. The following figure gives an impression of the effect.

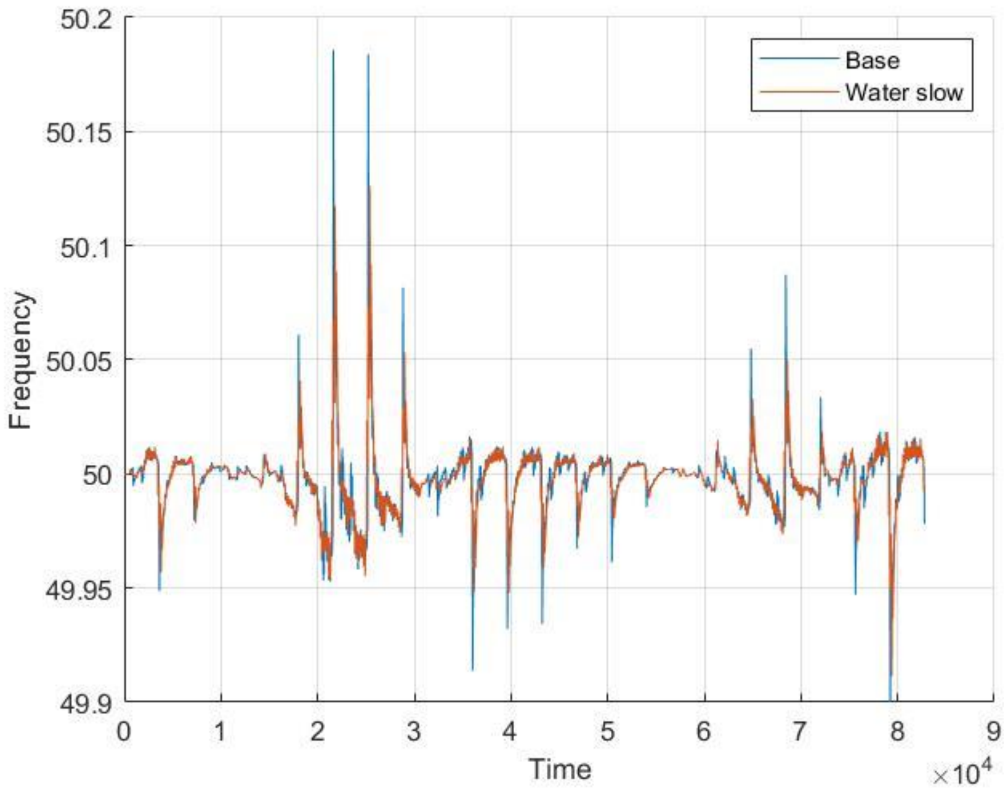


Fig. 32 – Water slow – ramping from 5 min before until 5 min after MTU

In figure 32, we can see a significant reduction in the height of frequency peaks. The maximum frequency is 50.1216 Hz and the minimum frequency 49.9114 Hz. Based on the following table and figure, we can observe the increase in quality.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Water slow	49.9983	0.0128	49.9114	50.1216	1.6423E-04

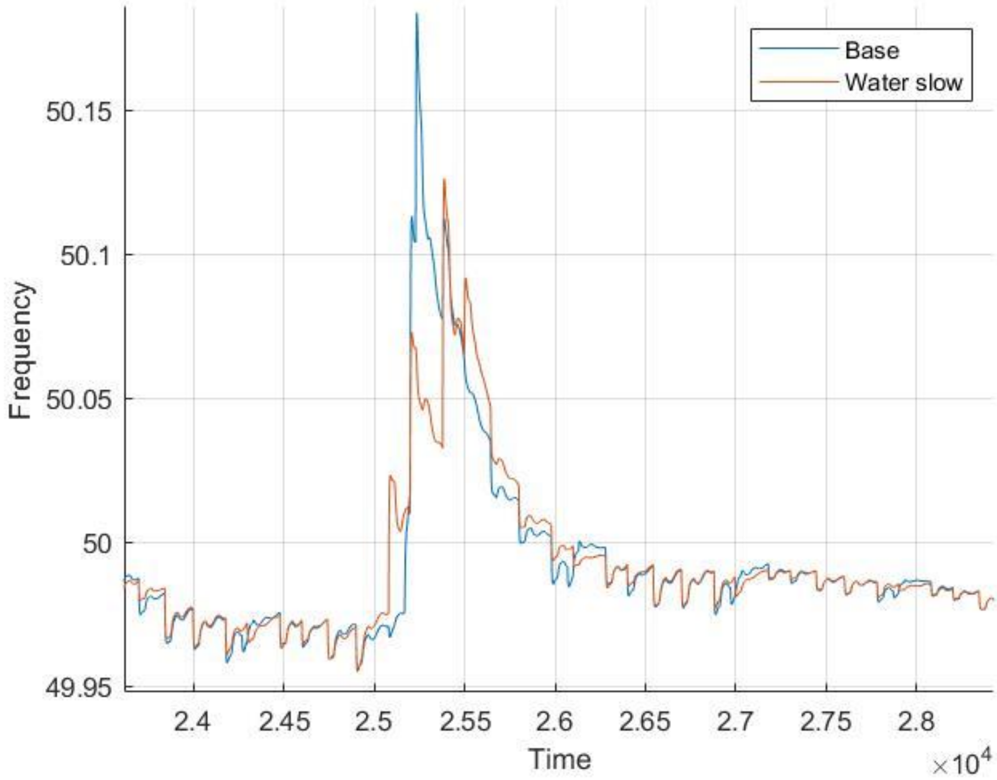


Fig. 33 – Water slow – zoom in

4.6.4 Additional FCR

For simulating the effect of additional FCR, the ramping behaviour of the base case has been used. Only the amount of FCR and the corresponding k-value was increased. While the FCR in the base case is 3000 MW and the k-value 27.000 MW/Hz, the simulation has been performed with 6000 MW FCR and a k-value of 42.000 MW/Hz. The new k-value of 42.000 MW/Hz corresponds to the original 27,000 MW/Hz + 15,000 MW/Hz from the additional 3000 MW FCR (3000/0.2Hz = 15,000 MW/Hz).

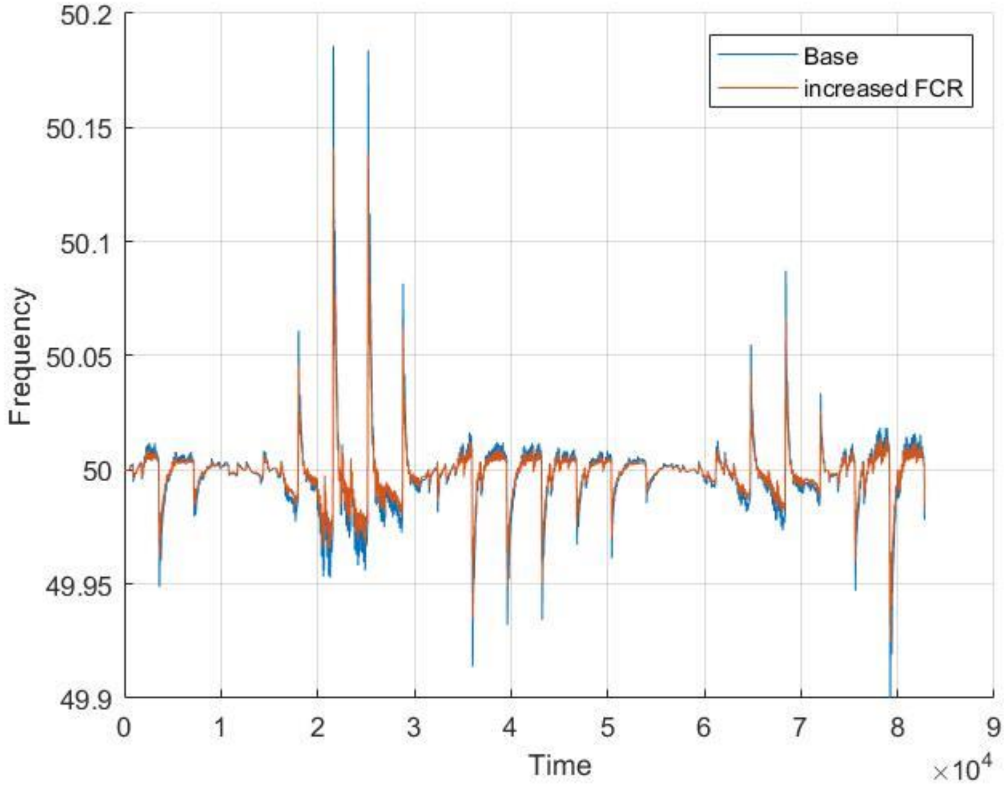


Fig. 34 – increased FCR – FCR: 6000 MW and k-value: 42,000 MW/Hz

Based on the figure above, we can see that frequency quality will increase. The frequency peaks are still there, but the size is reduced. Based on the simulation model, an increase of FCR will only reduce the height of the peaks, but not the dynamics of frequency. This we can see in the next figure. The following table show the statistics compared to the base case.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Increased FCR	49.9987	0.0109	49.9247	50.1411	1.19E-04

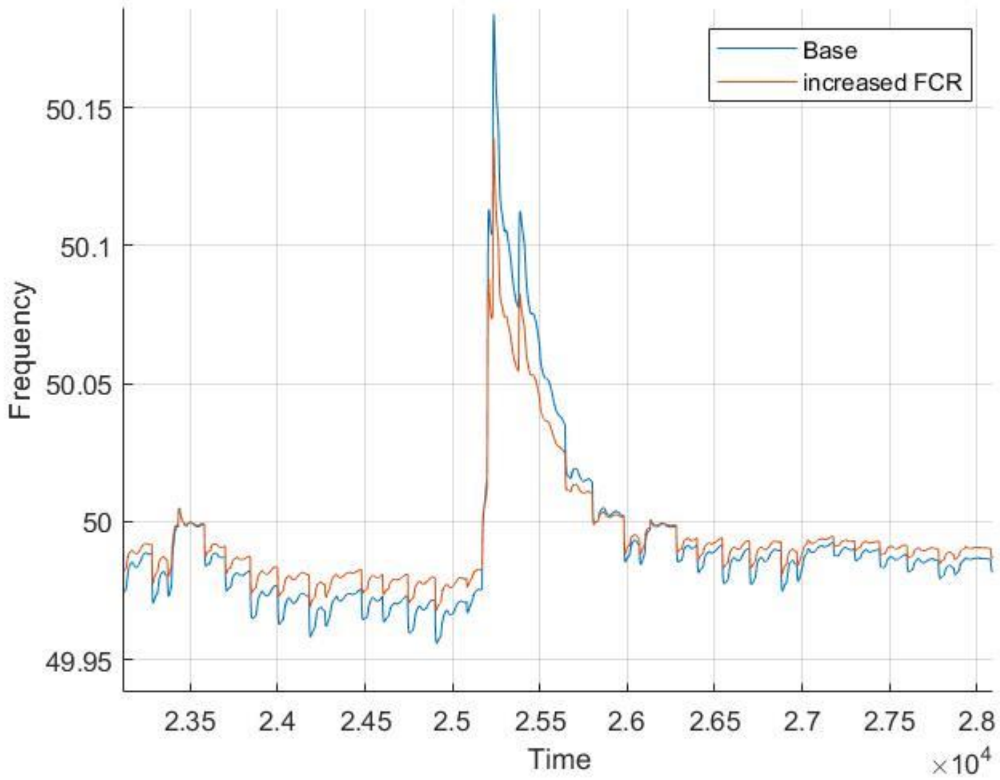


Fig. 35 – increased FCR – zoom in

4.6.5 Additional aFRR

To simulate the effect of additional aFRR, the ramping behaviour of individual generation types from the base case have been used and only the aFRR amount per LFC block has been increased. The MOL per LFC-Block has been increased from 200 to 2000 MW. The results of this simulation can be seen in the following figure, compared to the base case.

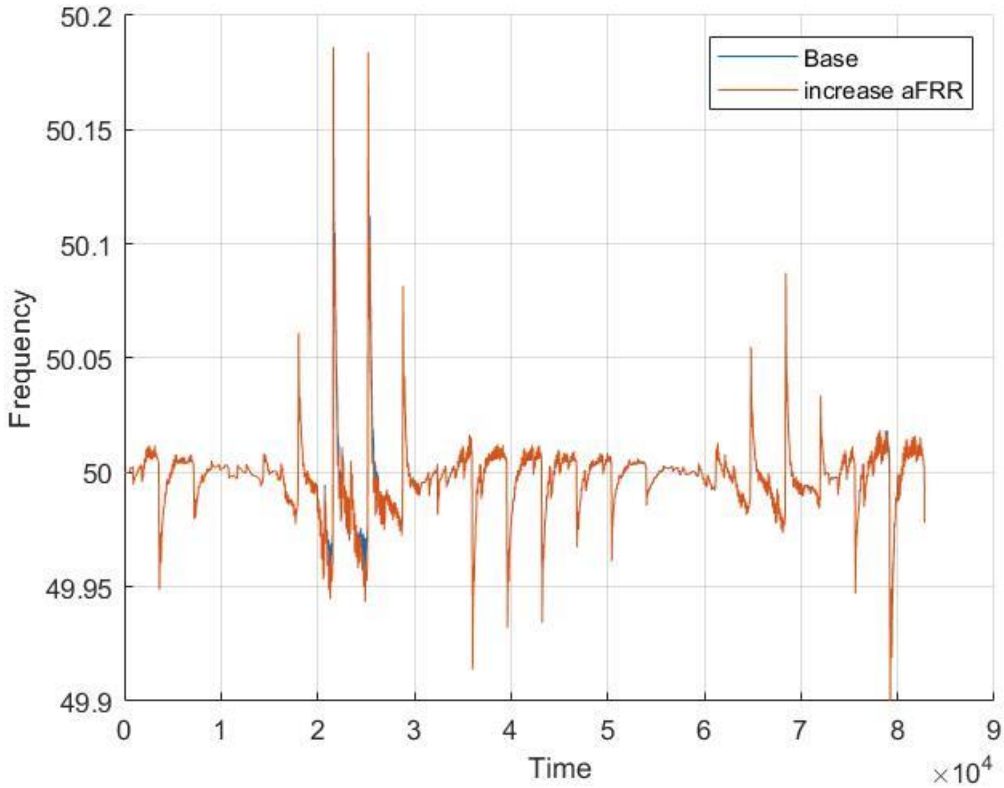


Fig 36 – increased aFRR

Based on the figure above, we can see that an increase of aFRR will not increase the frequency quality. The behaviour is similar to the base case. Only slight changes can be figured out, by comparing statistical factors. In addition, in the zoom in on the big DFD, we can see that there is no real change compared to the base case. We can observe some kind of an offset, but the dynamic behaviour of frequency will not be changed.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Increased aFRR	49.9979	0.0153	49.9001	50.1860	2.3340E-04

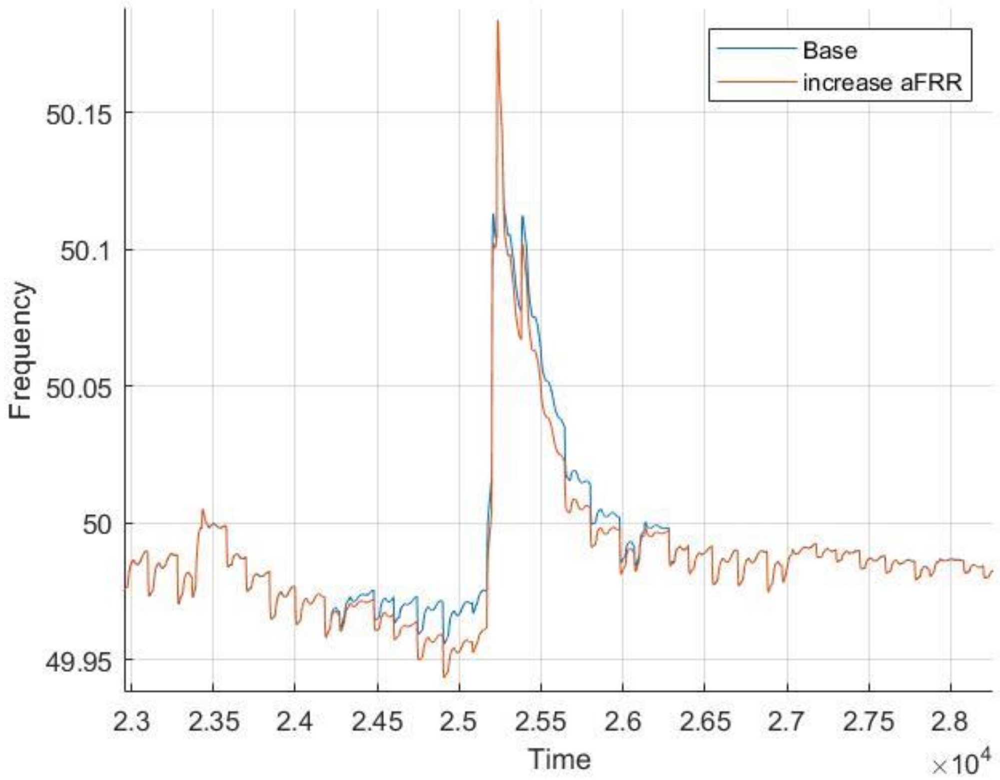


Fig. 37 – increased aFRR – zoom in

4.6.6 Higher K factor

As opposed to the increase of FCR, where FCR value as well as K-value has been increased, in this case only the K-value will be increased, while FCR will be constant with 3000 MW. The K-value for that simulation was assumed as 42,000 MW/Hz. The result can be found in the following figure.

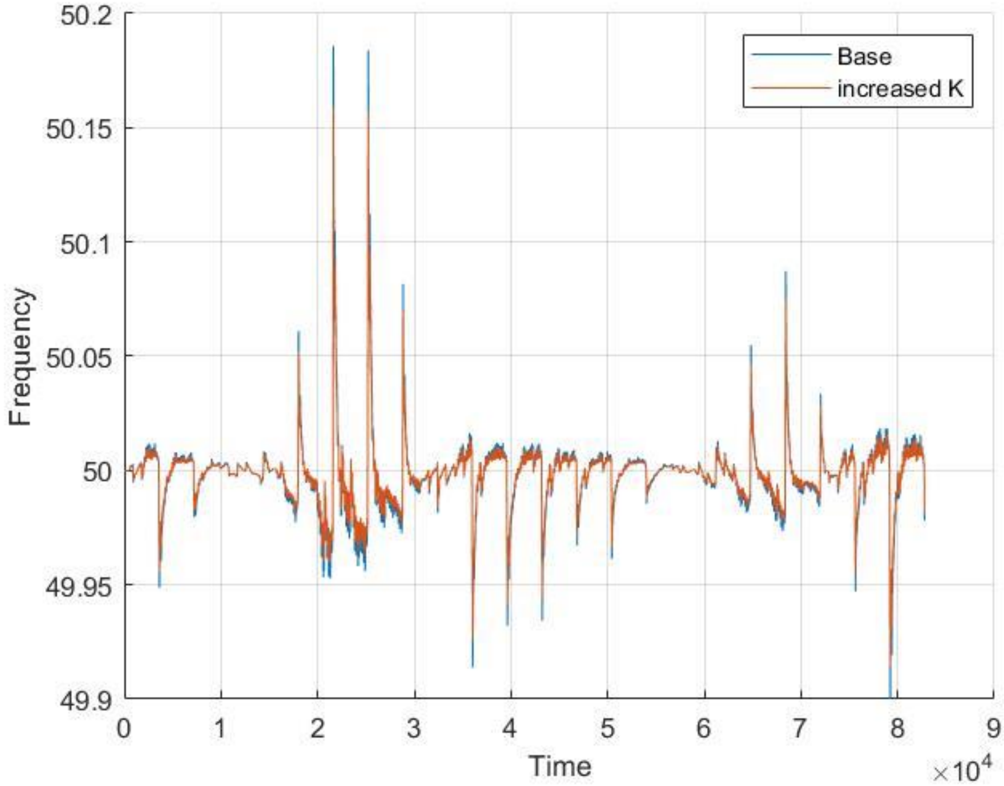


Fig. 38 – increased K-value – 42.000 MW/Hz by 3000 MW FCR

Based on the simulation, we can see that, at least for the DFD with small RoCoF up to 1 mHz / sec, an increase of K-value will also increase frequency quality. However, the observed gain in quality is quite small. Similar to the increase of FCR, an increase of K-value will reduce the frequency peaks, without any influence on the dynamic. The following figure shows this, while the following table shows the statistics compared to the base case.

Case	Mean	Standard deviation	Minimum	Maximum	Variance
Base	49.9982	0.0153	49.9	50.1858	2.35E-04
Increased K-value	49.9979	0.0153	49.9001	50.1860	2.3340E-04

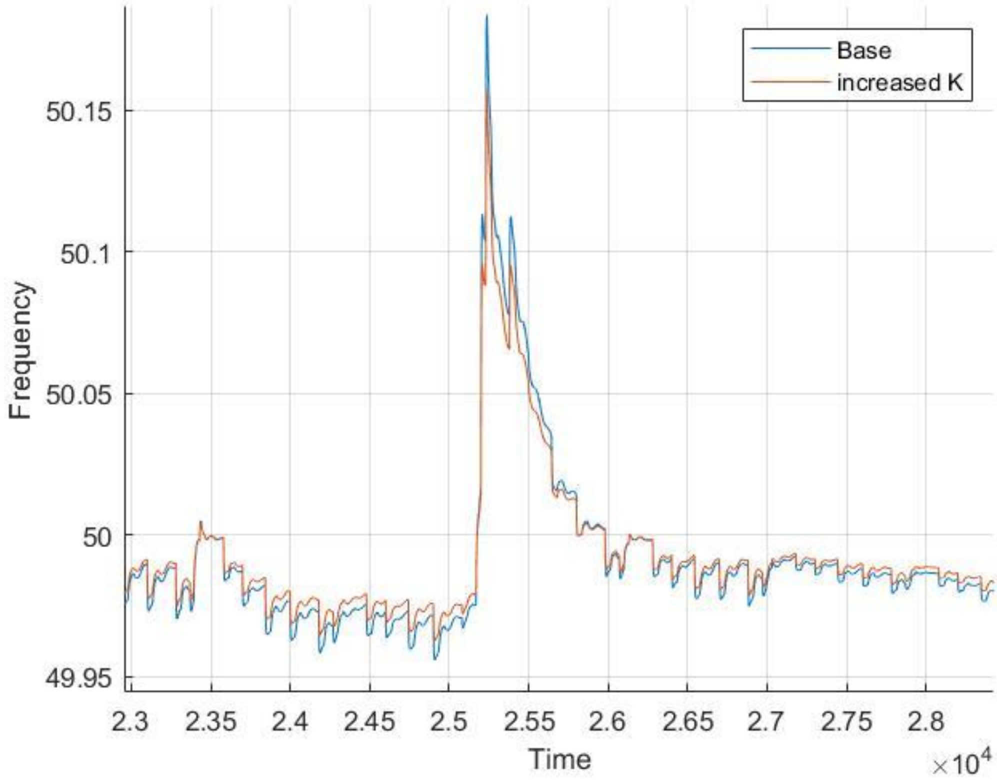


Fig. 39 – increased K-value – zoom-in

4.7 Impact study of the proposed solutions: Model B

It is important to be certain about the possible solutions for dealing with DFD and, in order to check the results from the simulations with the full model described before, a second set of simulations was executed by the task force.

4.7.1 Simulation model used

These simulations use a simplified model and check three typical hours of the evening, one with a mild DFD (hour 21 in the simulation), one with a very strong DFD with a RoCoF of 3 mHz / sec (hour 22 in the simulation) and one with a fast shutdown of a significant set of generation units at the change of the hour (hour 23 in the simulation).

The model uses the same inertia as the grid of CE but the grid is split up in four representative control blocks which distribute the active reserves (FCR, aFRR and mFRR) between them. Each control block contains 4 BRPs. Each BRP has an international programme with hourly changes, an internal programme with quarter-hourly changes, a load with a varying in a smooth way, and a set of generating units which are controlled to keep the imbalance of the BRP on a quarter-hourly basis as small as possible. The model emulates the reaction of the market parties (BRPs) as a reaction towards large imbalances; although such behaviour is very difficult to model accurately it is important to consider such a possible impact.

In each control block, one BRP has hydro units (very fast), one has coal units (very slow), one has gas units (intermediate speed) and one has no production. On top of the control mechanism to keep the quarter-hourly imbalance low, the coal BRP also has an anticipation built in to already move its unit to the programme of the next quarter-hour in the last five minutes, in order not to lag too much towards the next quarter-hour.

The base case simulation gives the result as shown in the graph below where the frequency at its lowest point is 49.84 Hz and the fast variation is just above 3 mHz / sec.

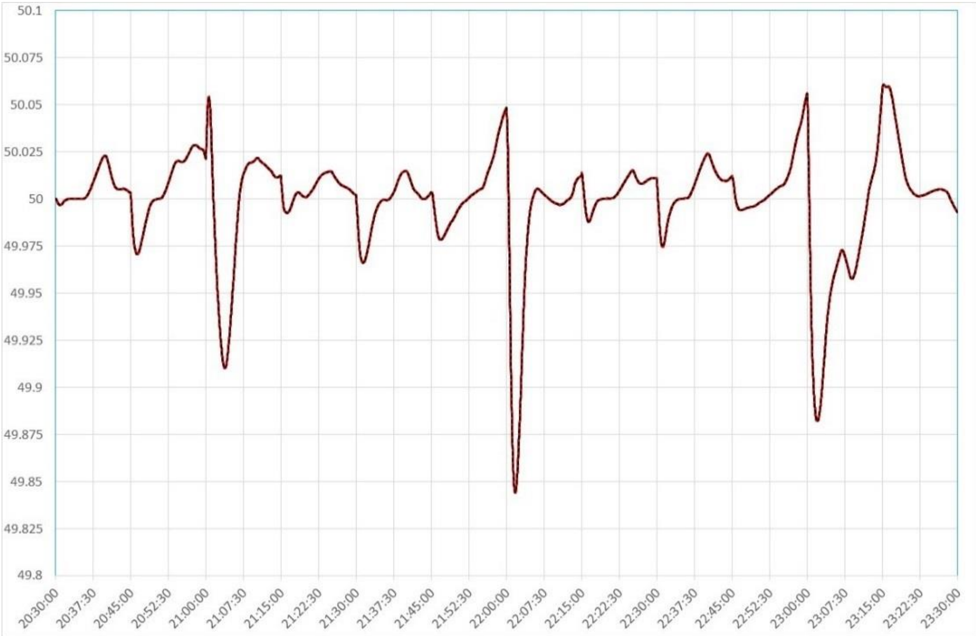


Fig. 40 – frequency simulated during the base scenario

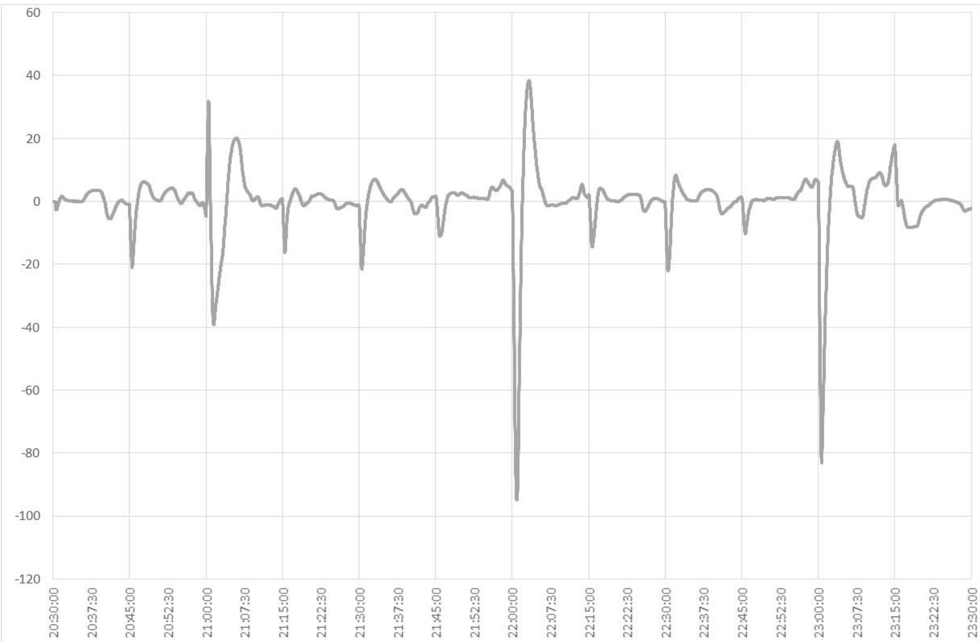


Fig. 41 – Rate of change of frequency, value on axis is measured in mHz over 30 seconds

4.7.2 15 minute trading

This solution was simulated by spreading the schedule change at the change of the hour over two successive MTUs, giving half the change at hour-15min and the other half at the hour. Statistically, it is defensible to say that if we move from hourly schedules to quarter-hourly schedules, the observed changes in schedule will be on average half as big from each MTU to the next, representing concretely an interpolation of the overall hourly based schedule.

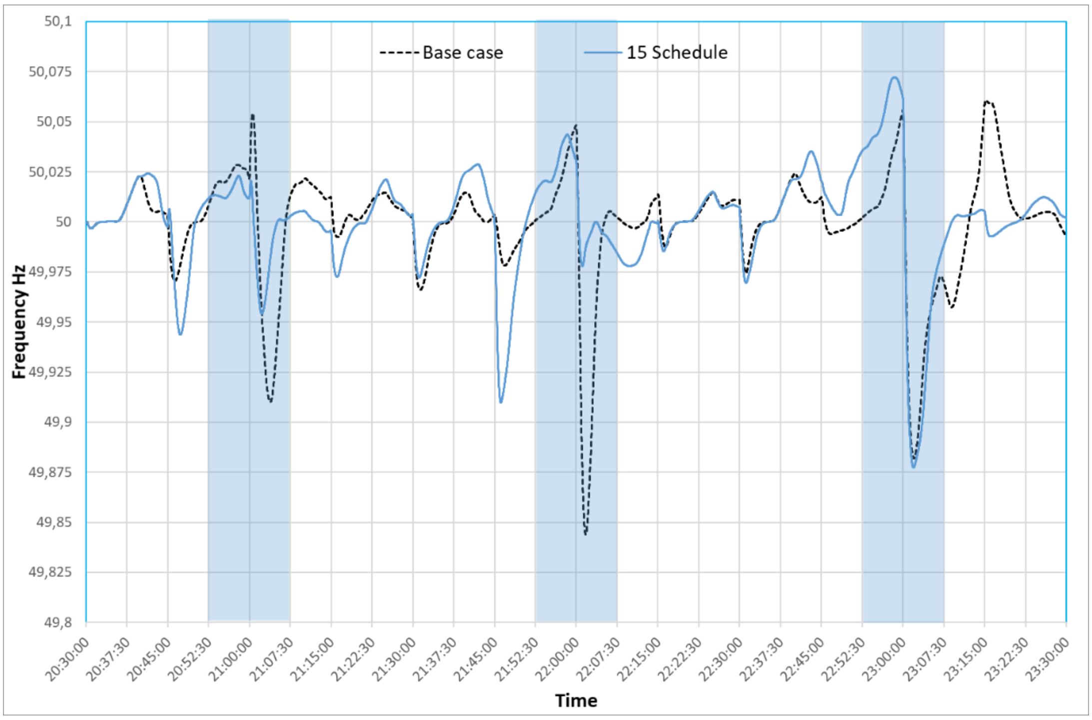


Fig. 42 – Simulated frequency profile of the 15 min MTU compared to the reference base case scenario profile

The simulated scenario based on 15 minutes MTU shows a smaller frequency deviation specifically during the hour changes where the DFDs occur (area shaded with blue in the above curve). This is in line with the expected behaviour, as smaller MTU duration will limit the gradient during schedule changes, while this creates new deviations compared to the base case (new schedule changes) the overall impact of DFDs is limited compared to the base case.

The simulations show that this solution allows most DFD to be reduced to acceptable levels, as the large DFD at 22:00 has even completely disappeared. However, it cannot solve the fast shutdown of a set of generation units programmed at a specific time, such as one simulated at 23:00. Here, the DFD will still subsist, as generation will still shutdown as in the base case.

Changing the MTU to 15 minutes will therefore solve most but not all DFD and can be seen as a major step forward, which might need to be complemented in some cases with a spreading of start-up or shutdown of specific generating units.

The box plot below covers only the frequency measurement during programme change, therefore illustrating specifically the impact of the simulated solution with respect to DFD time scale. We can observe that the Inter-quartile Range (IQR) is much narrower when 15 min MTU is considered and therefore there is an improved behaviour during DFD events.

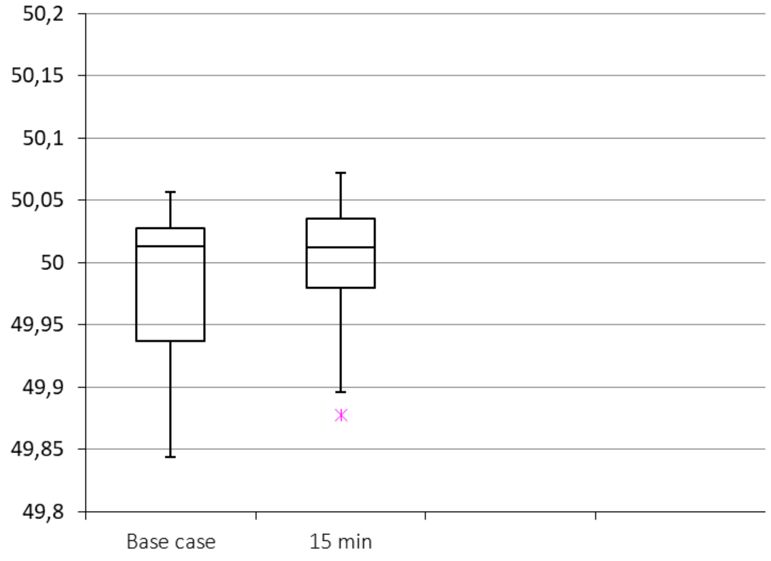


Fig. 43 – Box-whisker plot 15 min MTU comparing to the reference base case scenario profile

4.7.3 Ramping on load and/or generation schedules

The solution introducing the impact of ramping into the imbalance settlement during the change in schedules is simulated by inserting the ramping, which is already used today in the schedules between TSOs, into the schedules used by the BRP as well.

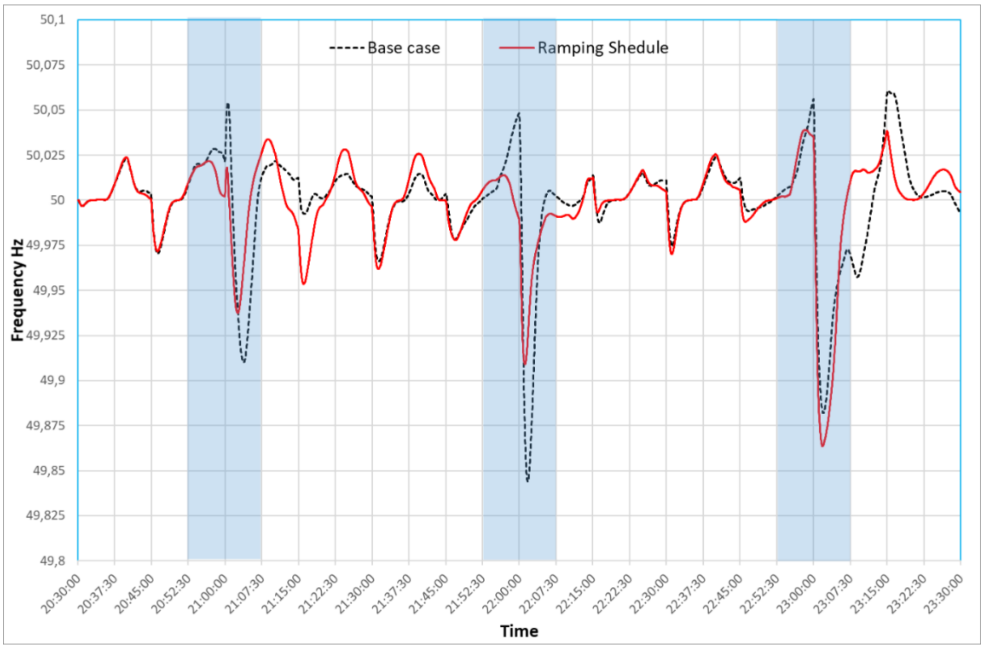


Fig. 44 – Simulated frequency profile of the ramping schedule compared to the reference base case scenario profile

The simulated base case scenario considering ramping on load and generation during programme change shows some improvements in term of frequency deviation specifically during the hour changes where the DFDs occur (area shaded with blue in the above curve).

The simulations show that this solution also allows most DFD to be reduced to acceptable levels. The large DFD at 22:00 has been reduced to 90 mHz. However, again, it does not solve the fast shutdown of a set of generation units programmed at a specific time, such as that simulated at 23:00. Here the DFD will still subsist as generation will still shutdown as in the base case.

The box plot below illustrates specifically the impact of the simulated solution with respect to DFD time scale. We can observe that the Inter-quartile Range (IQR) range is much narrower, as are the quartiles, presenting considerable improvement compared to the initial base case.

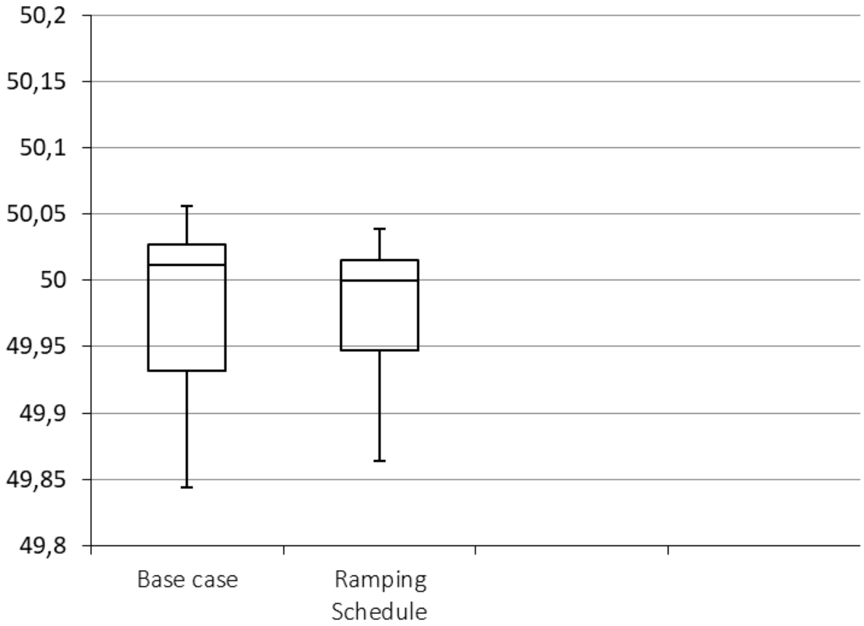


Fig. 45 – Box-whisker plot 15 min MTU and the reference base case scenario profile

4.7.4 Additional FCR

This simulation scenario investigates three possible sensitivities for increasing FCR volumes consisting of 1 GW, 2 GW increments covering the whole contractible frequency span (i.e. +-200 mHz); the suggestion within the report to contract a specific reserve of 2400 MW that covers only the range of the allowable DFD is included and referred to as the 75 mHz (i.e. +- 75 mHz) case in the following figure.

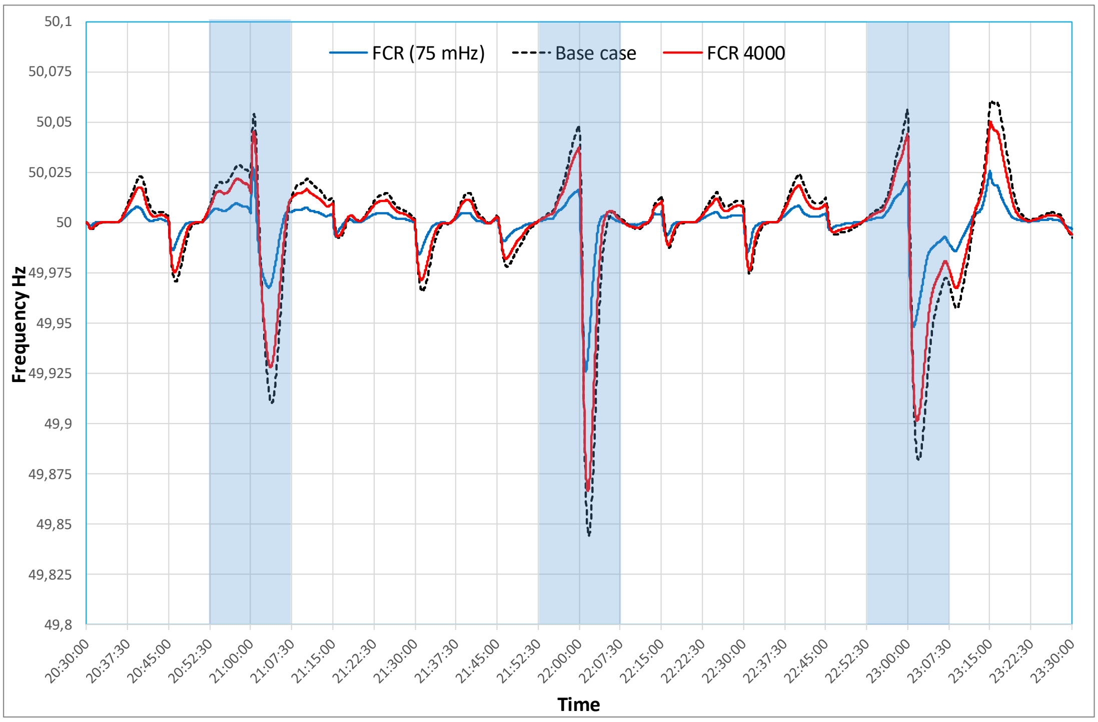


Fig. 46 – Simulated frequency profile of the FCR increase cases compared to the reference base case scenario profile

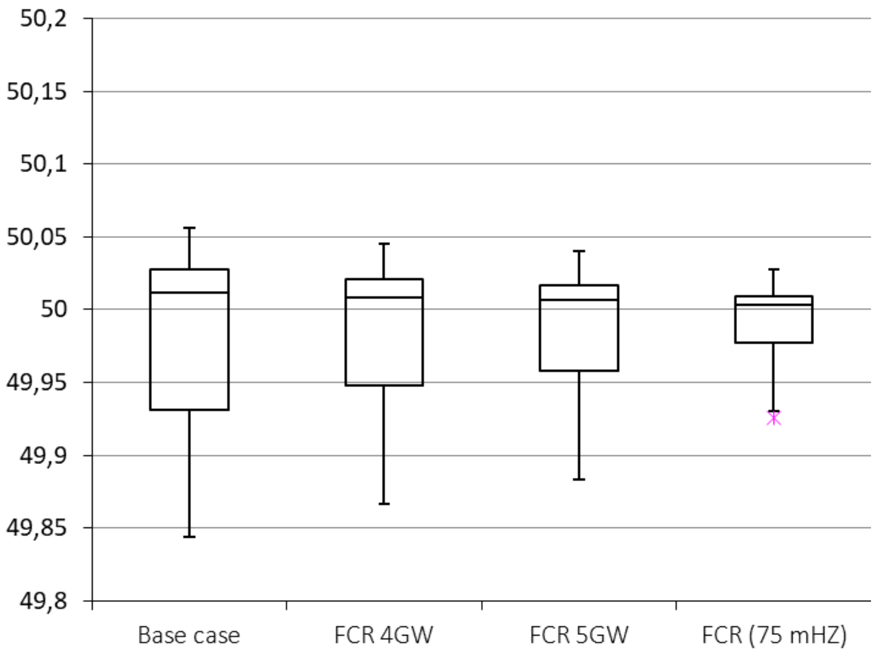


Fig. 47 – Box-whisker plot of the FCR increase and the reference base case scenario profile

Similarly, the box plot shows that higher FCR reserves always results in further improvement in terms of statistical spread during the DFD occurrence, which also remains valid for the overall operation as the additional reserves would generally improve the frequency quality of the system.

4.7.5 Additional aFRR

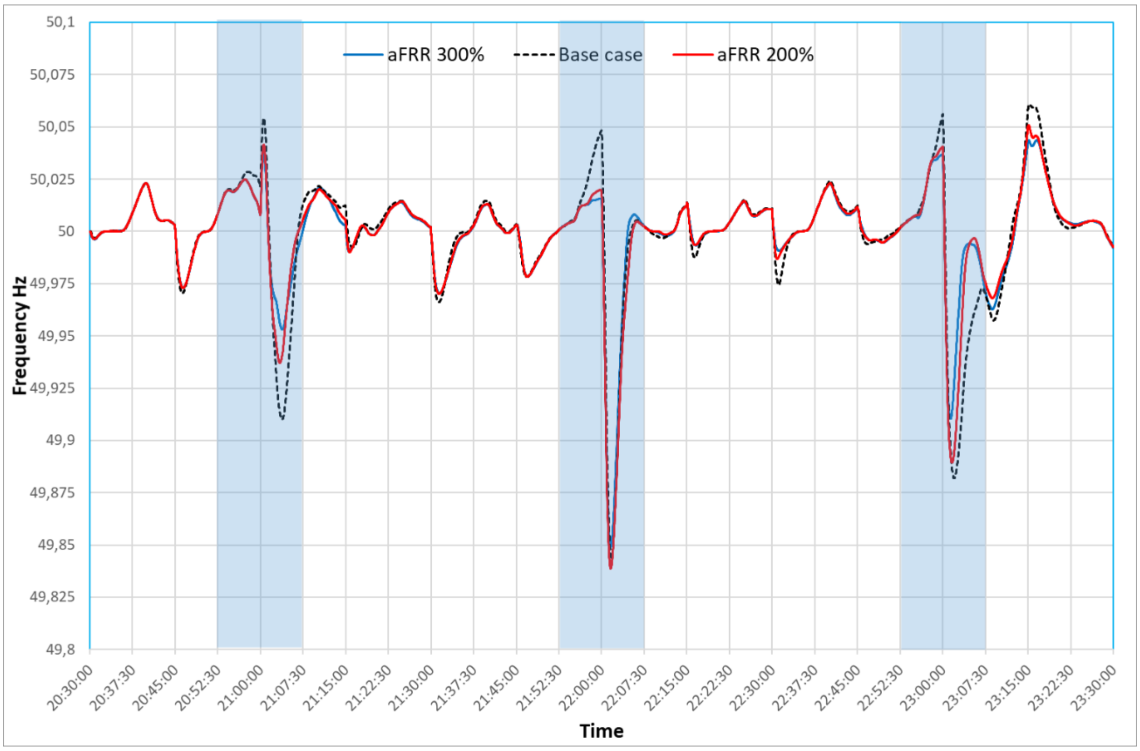


Fig. 48 – Simulated frequency profile of the aFRR increase cases compared to the reference base case scenario profile

The above figure illustrating the frequency profile shows that additional aFRR reserves have relatively limited impact on the frequency profile during DFDs even when the aFRR reserves are doubled or tripled. Limited improvement can be observed with respect to slow dynamic imbalances characterised by those which occur outside the DFD range.

The box plot figure below shows that additional aFRR volumes provide limited improvement on the frequency spread (smaller IQR), which is expected as the initiation and the terminal phase of the DFD are characterised by smaller frequency deviation; nevertheless, we still can observe outlier values, especially as we considerably increase aFRR volumes of more than double (outliers values are 1.5 IQR below the first quartile).

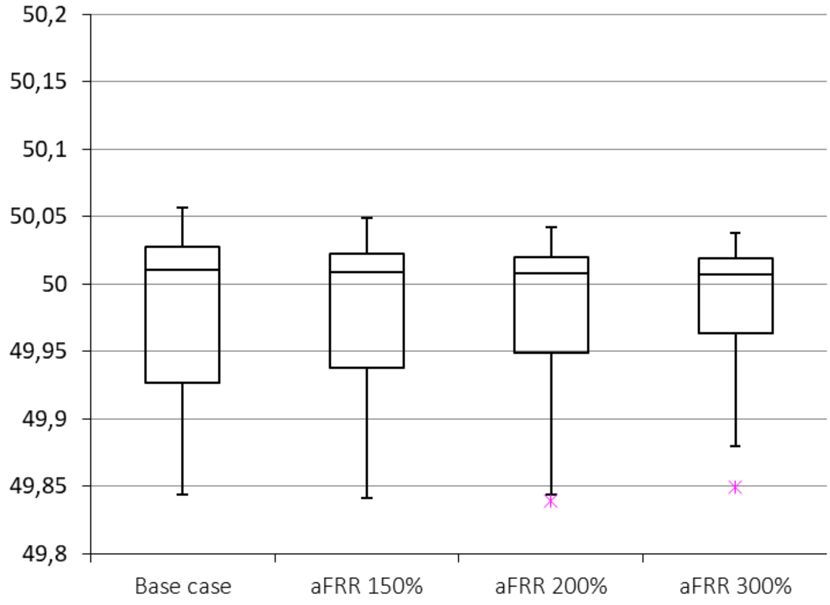


Fig. 49 – Box-whisker plot of the aFRR increase and the reference base case scenario profile

As expected, the frequency quality is better for the smaller DFD which can indeed be reduced with aFRR; however, for the large DFD the aFRR is not helping, and even making the situation a little bit worse, by cancelling the anticipatory behaviour of some market parties who already move their generation towards the programme of the next quarter-hour; therefore it is not recommended to increase aFRR with the purpose of reducing DFD.

4.7.6 Higher K factor

For this simulation, we tested the effect of doubling the K-factor in the controller of each control block. The idea is to test whether increasing a frequency behaviour of the centralised controllers helps in the reduction of DFD.

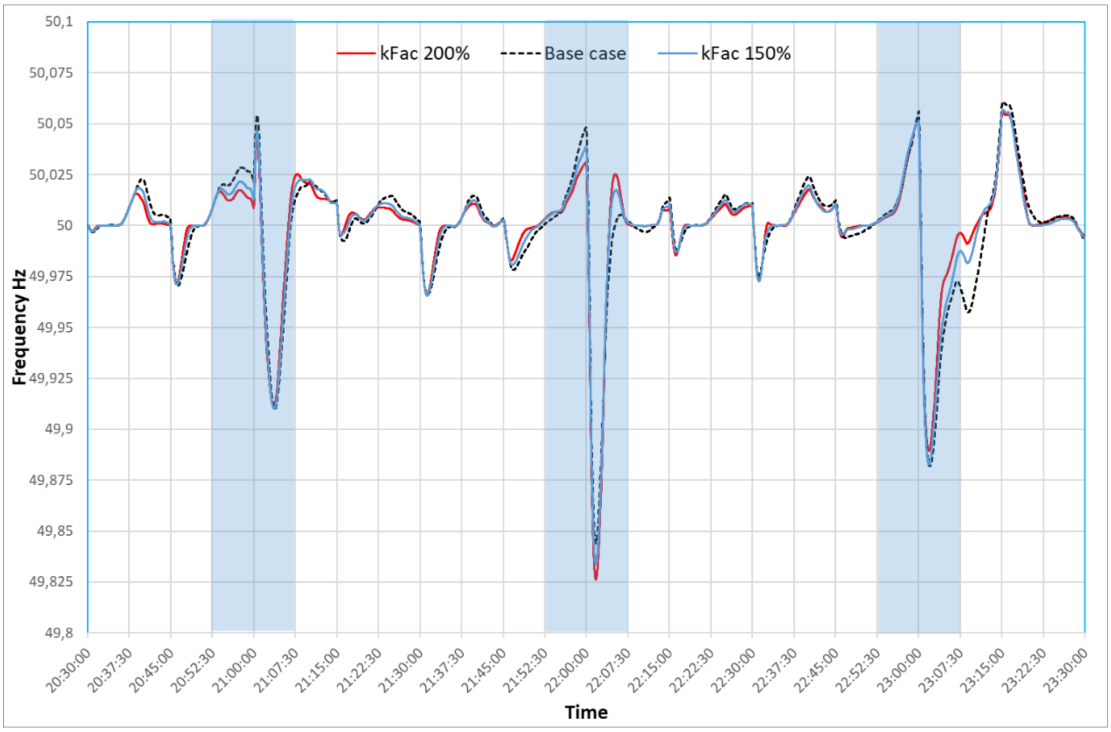


Fig. 50 – Simulated frequency profile of the k-factor increase cases compared to the reference base case scenario profile

The simulation case related to the increase of k factor provided similar results as the case of increasing aFRR capacity; in fact the k factor results in the higher activation of aFRR volumes until the full reserves are activated. The above figure shows a limited improvement in term of frequency profile specifically during the DfD occurrence; as expected and highlighted in section 4.4.4, the additional activation request of aFRR has limitations both in term of activation time and volume of reserves. In fact, we can see in the below box whisker plot that for all the tested k factor adaptation, an improvement is observed in the overall statistical spread but considerable presence of outliers remain. The impact in general remains limited as we increase the k-factor adaptation.

As we can see, the result was not improved specifically for the large DFD at 22:00. The frequency drops relatively deeper as in the base case, as it starts from a lower value just before the change of the hour.

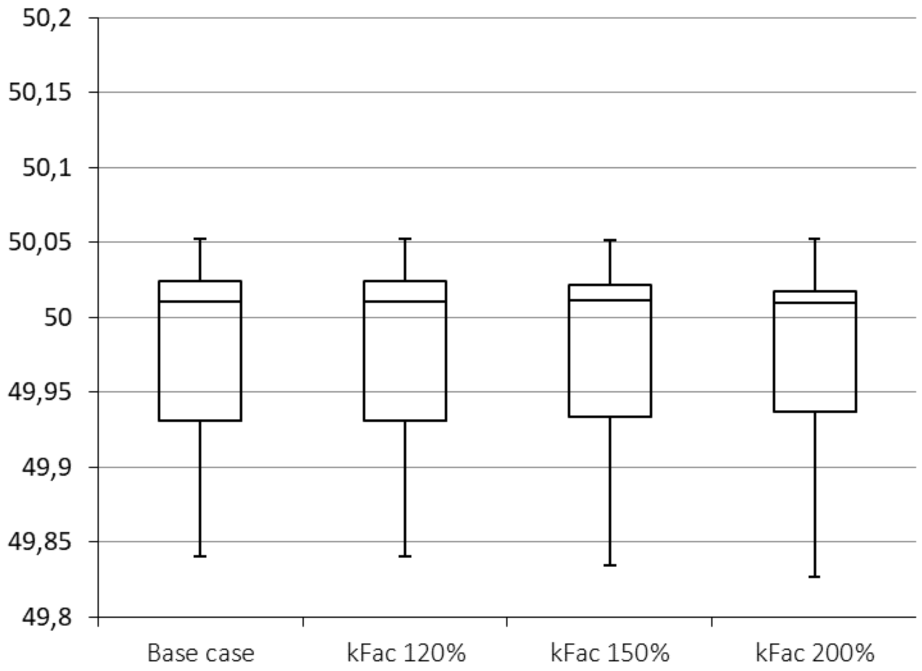


Fig. 51 – Box-whisker plot of the k-factor increase and the reference base case scenario profile

4.7.7 Ramping on Generation

In order to simulate ramping, we have put a maximum ramping of 5 MW / sec on all BRP in all control blocks. The slower ramping effect (which was not simulated in the base case) is applied to the generation shutdown at 23:00 and now spreads the shutting down of the generation over time, with a maximum change rate of 5 MW/sec. The result is given below and compared to the base case.

The result of this simulation shows that ramping does indeed work. Spreading the start and stop of units over time will greatly reduce the DFD. The effect is at least as good, if not better, than the simulation result on additional FCR.

In particular, the DFD at 23:00 which was due to the simultaneous shutdown of a large set of generating units has disappeared, as the unit's shutdown are now spread over time given the ramping requirement. There is a frequency overshoot just after 22:00 which is due to an exaggerated anticipation of a BRP, which was not needed given the slow ramping used by all parties. This also means that less anticipation will be required from BRP when the slower ramping of generation is used.

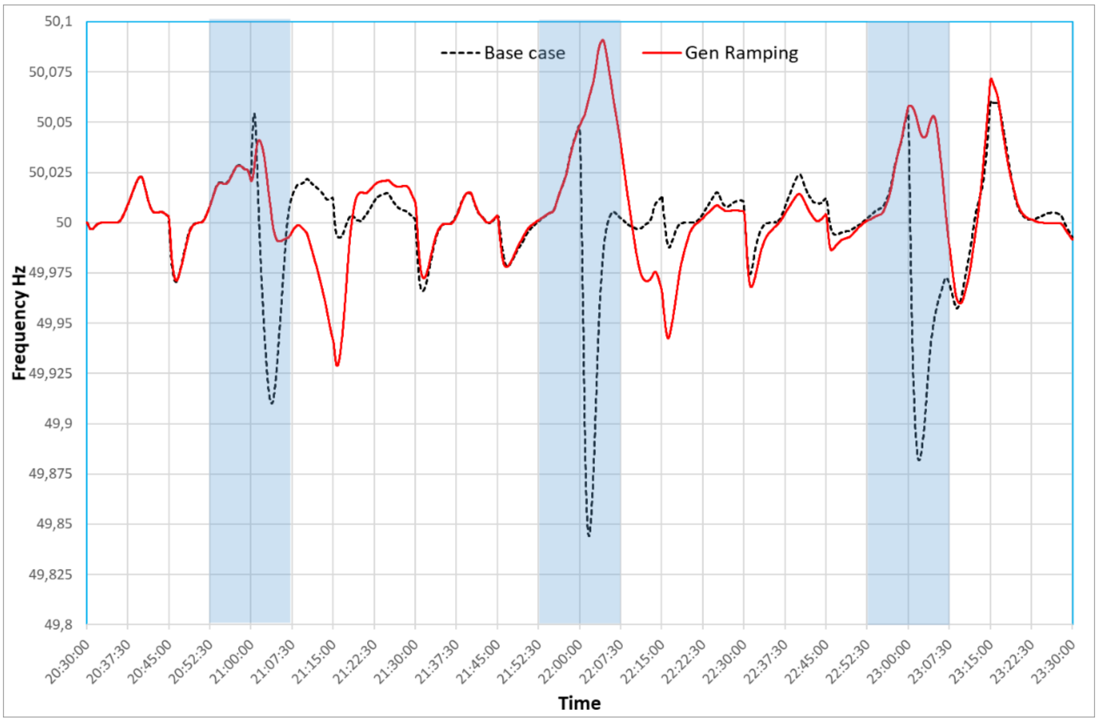


Fig. 52 – Simulated frequency profile of the ramping on generation case compared to the reference base case scenario profile

The figures above and below shows clearly for the investigated scenario that the limitation on the generation ramping did limit the amplitude of the frequency (21:00 and 23:00), yet the maximum observed frequencies in the time series is after 22:00 due to the anticipated effects of BRPs balancing their position.

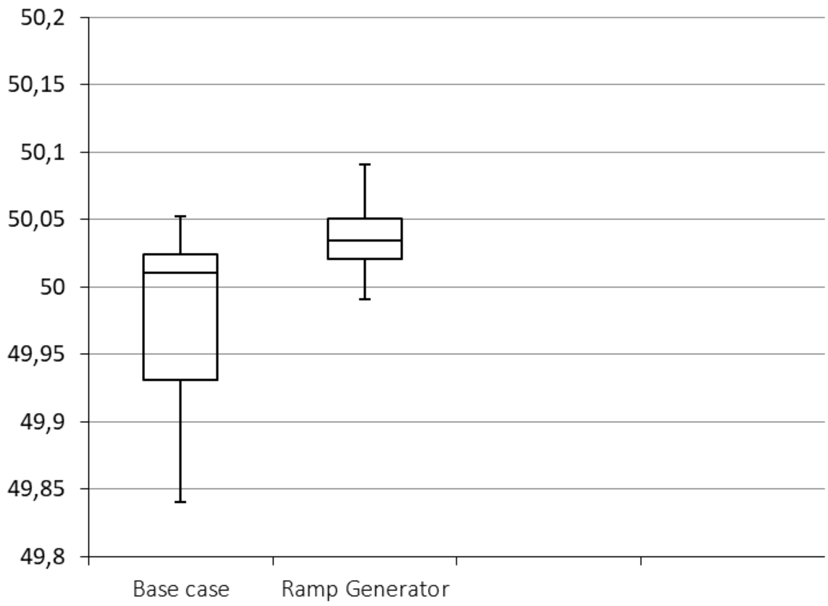


Fig. 53 – Box-whisker plot of the ramping on generation case and the reference base case scenario profile

4.7.8 Conclusion of the second set of simulations

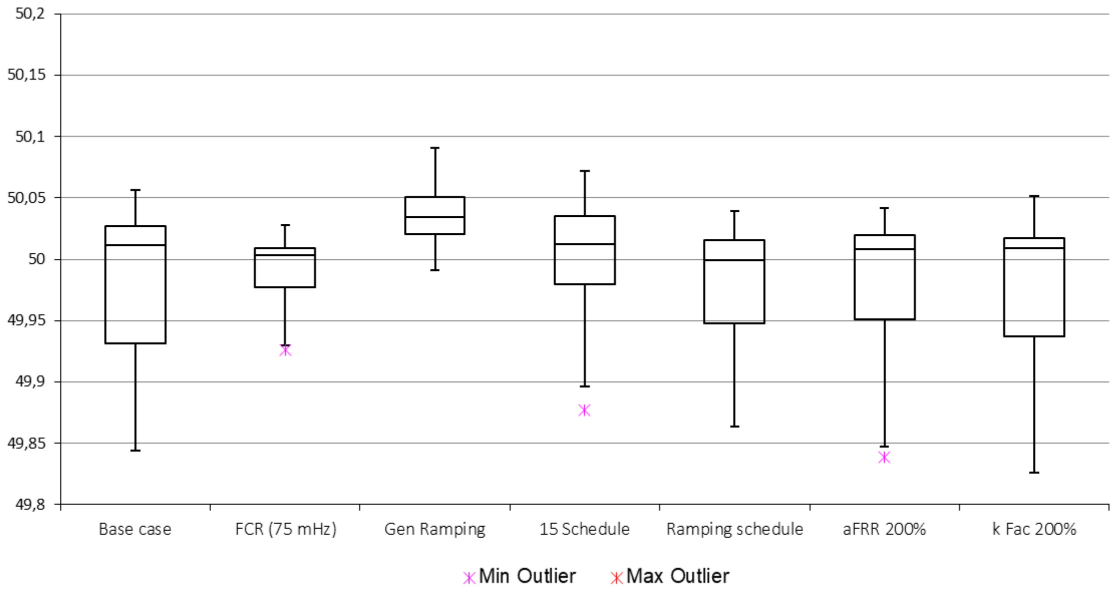


Fig. 54 – Box-whisker plot of the simulation solution and the reference base case scenario profile

The above figure provides a good statistical overview of the effectiveness of each of the investigated solutions. Certain solutions, such as the increase of FCR contracted volumes or ramping on generation, show effectiveness in mitigating the DfD issues. Other investigated solutions have, on the other hand, quite a limited impact for the assessed scenarios. Each control block, depending on their actual performance, can opt for the most cost-effective solution to achieve their compliance target.

5 Public Consultation

Following the first publication of this report in November 2019, ENTSO-E organised a consultation of all European market parties and stakeholders during the months of December 2019 and January 2020. ENTSOE position on DFDs and strong determination to reduce DFDs has also been presented to ACER, NRAs and European Commission at the Electricity Coordination Group meetings during 2019 and 2020. The discussions have been well received with a commitment from the ECG to support the reduction of the DFDs.

The consultation received considerable attention, and the non-confidential answers given by stakeholders are provided in the following paragraphs.

For each question, ENTSO-E has provided a response to all the comments received.

The feedback from stakeholders does not alter the conclusions of the report as the choice of mitigation measures is left to the different countries or control blocks and the report does not impose any specific solution on any individual country. The choice of mitigation measures will be decided by the individual TSOs, LFC blocks and their respective NRAs.

ENTSO-E sees a need for sufficient measures aiming at reducing root causes of DFDs (15 minutes MTU, ramping etc) which can be complemented by the measures aiming to mitigate the frequency deviations (e.g. FCR increase). The measures aiming at reducing root causes of DFDs are detailed in section 4.3, whereas the measures to improve frequency quality are detailed in section 4.4.

5.1 Do you see any effects of Deterministic Frequency Deviations on consumers or generation units in your portfolio today?

VERBUND Trading

VERBUND observes the deviation of the frequency close to the hour shift. We have not yet observed any negative influence on the generation units or load.

Oesterreichs Energie

Oesterreichs Energie`s members have not yet observed any negative influence on the generation units or load.

CEZ, a.s.

We do not observe any direct effect, but in general DFDs are impacting the TSO´s tools and choices (including balancing market and redispatching) and thus have an indirect impact on generators and other providers.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

Frequency deviations appear to have risen within the European internal market over the last couple of years. As network stability and security of supply are high commodities and essential to the system stability, measures should be found to reduce these deviations.

However, BDEW is extremely concerned that the measures described in the report to reduce DFD include interventions in the market such as the implementation of residual central dispatch and the application of ramping on load and generation schedules.

Furthermore, there has been no clear evaluation of the reasons for this increase. This would be helpful to better address potential solutions. In an evaluation, the following questions should be answered:

- What are the reasons for the increase of the rate of change of frequency and the increase of DFD since 2016, considering that frequency deviations have constantly decreased from 2011 until 2016?
- Is an influence on frequency deviations with the introduction of 6x4 hour blocks for FCR towards the end of the blocks expected?

BDEW welcomes the mentioned alternatives in the report such as the further development of already existing balancing products and the introduction of new products such as very fast reserves; for example, from battery storage. In general, the development and implementation of new products should be open to all technologies. We support a further development of solutions in this manner not only by TSOs but also by other stakeholders, such as producers and balancing service providers (BSPs).

EUGINE - European Engine Power Plants Association

Synchronous generators as developed in the turbine and gas engine industry have their drive-train coupled with grid frequency. As such, they are directly impacted by DFD. Units in frequency sensitive mode deploy the necessary FCR, and the impact for the plant owner would be the cost of deploying the FCR (mostly fuel cost and/or life use).

In the context of DFD not beyond ±200 mHz, the frequency deviation is minor enough to be considered as having a marginal impact on the life of the equipment.

Norsk Hydro ASA (Hydro)

We do see a risk for security of electricity supply caused by automatic reserves being tied up due to an increasing amount of frequency deviations not related to faults in the system. This could lead to the system not being able to cope with the occurrence of the dimensioning fault, or faults close to this. We consider it important to have clear targets on frequency quality, and a sound development of mitigating measures. Mitigating measures should, to the greatest extent possible, be developed as market mechanisms, designed to include both generators and loads. Industrial loads represent a substantial efficient reserve.

TIWAG-Tiroler Wasserkraft AG

Frequency deviations seem to have been rising within the European internal market for the last couple of years. As network stability and security of supply are high commodities and essential to the system stability, measures should be found to reduce these deviations.

However, we are very concerned that the measures described in the report to reduce DFD include interventions in the market such as the implementation of residual central dispatch and the application of ramping on load and generation schedules.

Furthermore, there has been no clear evaluation of the reasons for this increase. Where is the reason for the increase of the rate of change of frequency and the increase of DFDs since 2016 after decreasing between 2011 and 2016? Is an influence on frequency deviations expected due to the end of the introduction of 6x4 hour blocks for FCR? This would be helpful to better address potential solutions.

We welcome the mentioned alternatives in the report, such as the further development of already existing balancing products and the introduction of new products such as very fast reserves. We support a further development of solutions in this manner not only by TSOs but also by other stakeholders such as producers and BSPs.

VGB PowerTech Essen

The effects on Generation Units are: higher wear.

EnBW Energie Baden-Württemberg AG

Currently, we see no major impact of DFDs on consumers or generation units in our portfolio.

RWE Supply & Trading GmbH

We note that the occurrence of frequency deviations is increasing within the European internal market and agree that ensuring system stability as well as security of supply are the overarching tasks of the system operator.

However, we are of the opinion that to fulfil these tasks, market interventions, such as ramp restrictions on specific power plants and/or demand units or the implementation of residual central dispatch, must be limited and remain a measure of last resort. Instead, system operators should concentrate their efforts on the further development of harmonised balancing products as well as the introduction of new products. Most importantly, the development and implementation of new products should be open to all technologies. The further development of solutions in this manner should be done by TSOs in close cooperation with other stakeholders such as generators and balancing service providers.

IFIEC Europe

IFIEC Europe answer to the ENTSO-e stakeholder consultation on the DFDs report.

IFIEC Europe has taken note of the problems that have arisen in the last year with respect to DFDs.

IIFIEC Europe wants to make a clear distinction between two types of DFDs. On the one hand, those that arise a.o. with the changes in programmes at the hour marks. These have always existed, yet IFIEC Europe understands from the report from ENTSO-e that these are increasing due to changes in demand and supply patterns. IFIEC Europe, however, remains confident that these can be addressed with relatively minor modifications to the current market operation rules. IFIEC Europe, in any case, wants to stress that any such modifications should be taken with the minimisation of the overall system cost in mind, in order to avoid consumer invoices being unduly inflated. For IFIEC Europe it is, moreover, important that any costs shall be attributed to those parties creating the increasing fluctuations that could lead to concerns with respect to DFDs.

However, there are the DFDs that result from errors or negligence at the level of TSOs, as can be observed from the incident in January 2019 discussed in the report as the basis of this consultation but also from previous events concerning DFDs leading a.o. to clocks lagging behind in the European connected grid due to non-balanced energy in- and output in certain zones. For this category of DFDs, IFIEC Europe is strongly of the opinion that TSOs should check, validate and improve their internal processes as well as their collaborative mechanisms to avoid such DFDs from occurring in the future. For IFIEC Europe, the costs resulting from coping with such DFDs must be completely attributed to those parties, including TSOs, and responsible for them, and not be socialised amongst all grid users in the interconnected zone. IFIEC Europe also observes that even balancing reserves were used to cope with the observed DFDs; in general, IFIEC Europe is not opposed to safeguards to avoid real system problems because of DFDs, but it is not willing to increase the cost of all grid users due to either an increase in the reserved balancing capacity and/or new costly mechanisms to counter the below par performance of (certain) TSOs. Instead, these issues should be addressed by the TSOs and ENTSO-e in collaboration with the regulating authorities (if necessary under the auspices of the Agency and/or the European Commission and/or the Member States) and, as mentioned above, the costs should be clearly attributed under a "polluter pays" principle. Last but not least, IFIEC Europe strongly urges TSOs to analyse and validate, in collaboration with regulating authorities, their internal processes to avoid any such DFDs in the future

Finally, IFIEC Europe would like to emphasise the necessity of European TSOs to focus properly on frequency quality or grid security in more general terms. In a changing power system, this becomes more important than ever before. Mitigating measures should, to the greatest extent possible, be developed through technology neutral market mechanisms, providing marketplaces for relevant participants, including industrial loads. It is important, however, to consistently focus on minimising the overall system costs when introducing new measures.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Synchronous generators as developed in the turbine and gas engine industry have their drive-train coupled with grid frequency. As such, they are directly impacted by DFD. Units in frequency sensitive mode deploy the necessary FCR, and the impact for plant owners would be the cost of deploying the FCR (mostly fuel cost and/or life use).

In the context of DFD not beyond ±200 mHz, the frequency deviation is minor enough to be considered as having a marginal impact on the life of the equipment.

Eurelectric

At Eurelectric we do not have a portfolio (being an association), but we would like to make the following comments:

- Frequency quality is important both for consumers and generators.
- Consumers are more sensitive to frequency quality, both industrial clients for its processes as well as residential customers.

Endesa S.A.

As mentioned in the report, in Spain we have a very small DFD because of the excellent functioning of aFRR provisions through large regulation areas, and consequently there are few effects on our generators.

However, we do agree that: 1) DFD could have an effect on generators, and these effects would be higher in terms of synchronous generation than non-synchronous generation, and 2) synchronous generation is designed and tuned to operate efficiently and safely within a limited operational domain defined mainly by frequency and voltage. Frequency limits are a concern for rotating machines, as deviation from the typical frequency ranges can affect generation lifecycle or cause damage. Non-synchronous generation is more used to running at variable load.

Eins Energie in Sachsen GmbH & Co. KG

Eins has been following with great concern the increasing frequency deviations since 2014. By 2018 the number of deviations of more than +- 75m Hz had doubled. In 2019, several frequency deviations reached almost 200 mHz, and on 02 October 2019 this even reached more than 200m Hz. According to public reports, a turbine of the waste incineration plant Baar-Ebbenhausen in the Tennet network was severely damaged in this incident. Source: https://pfaffenhofen-today.de/52628-gsb-091019

It is therefore necessary to ensure rapid efforts to reduce both the deterministic and statistical frequency deviations.

Energie AG Oberösterreich Trading GmbH

We did not observe any negative influence in our portfolio today.

EDF

Frequency quality is important both for consumers and generators. Indeed, any degradation in frequency impacts both.

As an electricity producer, EDF considers that, regarding generation, frequency deviations impact both existing and new facilities in terms of capabilities as well as operation. Generation units are indeed designed to be able to stay connected over a wide range of frequency with associated durations (both existing units with their declared capabilities and the new ones which have to comply with the requirements of the RfG network code). In fact, FCR providing units, responding instantly to these deviations, face steep gradients on generation which lead to the ageing of the components involved and therefore to extra costs for the owners of such facilities.

Regarding consumers, both industrial clients for their processes as well as residential customers for their various appliances are very sensitive to frequency quality, and they are the primary beneficiaries of accurate frequency management.

EFET - European Federation of Energy Traders

As a representative organisation, EFET itself does not have a portfolio of assets or contracts.

Edison - EDF Group

Edison, as a generator, is impacted by DFDs. Edison owns and operates FCR providing units that have to respond instantly to these deviations, in this way facing sharp gradients on power generation which lead to the ageing of the components involved and therefore to extra costs.

Summary of stakeholders' answers

Most market parties do not experience any negative influence of frequency variations. However, it is acknowledged that frequency quality is important both for consumers and generators.

Synchronous generators as developed in the turbine and gas engine industry have their drive train coupled with grid frequency. As such, they are directly impacted by DFD.

FCR providing units, which have to respond instantly to these deviations, face sharp gradients on power generation which lead to the ageing of the components involved and therefore to extra costs.

Some stakeholders report the risk of higher wear on generation units. DFDs could have effects on generators, and these effects would be higher in synchronous generation than in non-synchronous generation. Synchronous generation is designed and tuned to operate efficiently and safely within a limited operational domain defined mainly by frequency and voltage. Frequency limits are a concern for rotating machines, as deviation from the typical frequency ranges can affect generation lifecycle or cause damage.

Regarding consumers, both industrial clients for their processes, as well as residential customers for their various appliances, are very sensitive to frequency quality, and they are the primary beneficiaries of accurate frequency management.

It is also recognised that as network stability and security of supply are high commodities and essential to system stability, measures should be found to reduce these deviations. The risk for security of electricity supply is acknowledged, given that automatic reserves are being tied up due to an increasing amount of frequency deviations not related to outages. This could lead to the system not being able to cope with the occurrence of unforeseen outages. For instance, IFIEC Europe emphasises the necessity of European TSOs focusing properly on frequency quality or grid security in general. In a changing power system, this becomes more important than ever before.

ENTSO-E Response

Impact on generation and on consumers is limited but existing. ENTSO-E notes this and confirms its intention to reduce DFDs in order to reduce these negative impacts on market parties.

ENTSO-E shares the concerns related to system security and agrees that reserves should not be unduly used for deterministic variations and kept as much as possible for unforeseen outages.

ENTSO-E also agrees that in the changing environment of the power system, this will become increasingly important to follow.

5.2 Are you already participating in any initiative to reduce frequency variations in Continental Europe? If so, which one(s)?

VERBUND Trading

The Austrian TSO APG discusses with a group of Austrian BSPs the topic of DFDs on a national level. The goal of the discussion is to find some mitigating measures for DFDs.

Oesterreichs Energie

The Austrian TSO APG discusses with Oesterreichs Energie and a group of Austrian BSPs the topic of DFDs on a national level. The goal of the discussion is to find some mitigating measures for DFDs.

CEZ, a.s.

It would be good for the report to provide clarity on these initiatives. We do not know of any “official initiative” as such.

For any initiative, we think that the following points should be respected:

- Requirements should be carefully analysed. The report itself sets an objective of “an acceptable DFD = 75 mHz”, whose implementation will become, to our understanding, an official “initiative” by ENTSOE.
- Governance: the report points out “that TSOs can choose the most effective and efficient measure to reduce its contribution to DFDs”. In that respect, structural solutions should not be solely decided by TSOs based on a given “quality target” which could be linked to the conjuncture.
- Measures are to be framed by a sound governance involving not only TSOs but also other stakeholders (producers, consumers, Balancing Service Providers).

EUGINE - European Engine Power Plants Association

EUTurbines and EUGINE members design equipment and power plants to deliver the grid-code-required frequency response MW versus time trajectory.

Norsk Hydro ASA (Hydro)

In Germany, our primary smelter Rheinwerk is participating with reserves named Quickly Interruptible Loads “Schnell abschaltbare Lasten” – in “Die Abschaltverordnung”. In Slovakia, no frequency markets available for participation by end-use exist, to our knowledge. Furthermore, for your information, in Norway our consumption units do participate in the capacity market (RKOM) for mFRR (RKM), and in a pilot market for fast frequency reserves (FFR). Our production units in Norway attends various frequency markets.

TIWAG-Tiroler Wasserkraft AG

The Austrian TSO APG discusses with Oesterreichs Energie and a group of Austrian BSPs the topic of DFDs on a national level. The goal of the discussion is to find some mitigating measures for DFDs.

VGB PowerTech Essen

Yes, we conducted a research Project with the University: "Control-regime Interaction between Power Stations and Supply Grids in a Deregulated Power Supply System - Measures to Reduce Power Station Load"

https://www.vgb.org/en/research_project306.html

The author, Dr. Weißbach, did his dissertation on this subject and is now at TransnetBW.

EnBW Energie Baden-Württemberg AG

We are participating in the FCR-cooperation.

RWE Supply & Trading GmbH

Yes

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

EUTurbines and EUGINE members design equipment and power plants to deliver the grid-code-required frequency response MW versus time trajectory.

Eurelectric

- It would be good for the report to provide clarity on these initiatives. We do not know of any “official initiative” as such.

For any initiative, we think that the following points should be respected:

- The requirements should be carefully analysed. The report itself sets an objective of “an acceptable DFD = 75 mHz” whose implementation will become, to our understanding, an official “initiative” by ENTSOE.
- Governance: the report points out “that TSOs can choose the most effective and efficient measure to reduce its contribution to DFDs”. In that respect, structural solutions should not be solely decided by TSOs based on a given “quality target” which could be linked to the conjuncture.
- Measures are to be framed by a sound governance involving not only TSOs but also other stakeholders (producers, consumers, Balancing Service Providers).
- Instead of each TSO triggering solely its own solution, RSC could provide guidance on a coordinated solution.

Eurelectric regrets that solutions coming from load are almost absent in the report; for example, efficiency from solutions coming from tariffs incentives could be analysed.

Endesa S.A.

In Spain there is any initiative

Statkraft

No.

Energie AG Oberösterreich Trading GmbH

We are discussing the topic with the national TSO and a group of other BSPs to find acceptable national solutions for all stakeholders.

EDF

We are not aware of any official "initiative" in Europe. EDF recalls that "Spot Power Balancing" or "Residual Central dispatch", even if not "official" initiatives, are already in place in some countries. Their "feasibility and efficiency" can already be assessed.

The report sets that (4.6.5) "an increase of aFRR will not increase the frequency quality. The behavior is similar to the base case". EDF recalls that such unofficial "initiatives" already exists in some countries and the efficiency can also be assessed.

EDF remains open to discussing market design elements which could address ENTSO-E's issues.

EDF deems that any requirement should be carefully analysed. The report itself sets an objective of "an acceptable DFD = 75 mHz" whose implementation will become, to our understanding, an official "initiative" by ENTSO-E. Setting such a constraint to 8,760 hours a year requires further analysis. It is also the case for other constraints (e.g. "a DFD should not leave the interval of +/- 50 mHz for more than 5 minutes").

EDF would like to recall that "Regional Security Coordinators" (RSC) duties are defined by Regulation on System Operation (SOGL) – reinforced by the Clean Energy Package – which include, for example, operational planning security analysis and short and very short term adequacy forecasts. Therefore, guidance on how to handle DFDs in a coordinated manner should be provided by RSC, for example by forecasting critical moments while relaxing other periods with less gravity. Instead of each TSO triggering solely its own solution, the RSC could provide guidance on a coordinated solution.

As to governance, the report points out "that TSOs can choose the most effective and efficient measure to reduce its contribution to DFDs". In that respect, EDF deems that the efforts to contain DFDs should be shared among TSOs and structural solutions should not be solely decided by TSOs based on a given "quality target", which could be linked to the conjuncture. Secondly, measures are to be framed by a sound governance involving not only TSOs but also other stakeholders (producers, consumers, Balancing Service Providers …).

EDF regrets that solutions coming from load are almost absent in the report, for example solutions coming from tariff incentives could be further analysed.

EFET – European Federation of Energy Traders

As a representative organisation, EFET itself does not participate in initiatives to reduce DFDs.

If initiatives currently exist in certain control areas to reduce DFDs, we would appreciate more details on those initiatives in the report. For any initiative that may be undertaken, we believe that the governance should be clarified: TSOs should not decide unilaterally without consulting the market on the structural solutions that may be chosen.

Edison – EDF Group

No, Edison is not aware of any initiative specifically aimed to reduce DFD.

Summary of stakeholders' answers

Several research initiatives are mentioned in the stakeholders' answers[5]. Stakeholders note that the Austrian TSO is in discussion with several parties in Austria on possible mitigation measures.

EDF suggests that guidance on how to handle DFDs in a coordinated manner could be provided by RSCs, for example by forecasting critical moments, while relaxing other periods with less gravity. Instead of each TSO triggering solely its own solution, the RSC could provide guidance on a coordinated solution.

Finally, several market parties find that solutions coming from load are almost absent in the report, for example efficiency from solutions coming from tariffs incentives could be analysed.

ENTSO-E Response

ENTSO-E wishes to thank the respondents of the consultation for the additional information provided. This will be used in the further development of the mitigation measures in each control block or country inside Continental Europe.

[5] https://www.vgb.org/en/research_project306.html
https://www.ise.fraunhofer.de/en/research-projects/pv-power-plant-of-the-future.html
https://www.nationalgrideso.com/innovation/projects/enhanced-frequency-control-capability-efcc
https://www.smarternetworks.org/project/nia_ngso0026
https://www.enargus.de/pub/bscw.cgi/?op=enargus.eps&q=verbundnetzstabil&id=871547&v=10
https://der-lab.net/wp-content/uploads/2018/11/Rogalla_postfinal_181016_IRED-SideEvent_VerbundnetzStabil_Rogalla.pdf

5.3 One of the proposed solutions is to move towards a 15 minute Market Time Unit for internal and cross-border energy exchanges. What would be the positive or negative effects of this on your business?

VERBUND Trading

VERBUND welcomes the idea of moving towards a 15 minute MTU for internal and cross-border energy exchanges in all control blocks. In Austria and Germany, we have already had positive experiences with an MTU of 15 minutes. The exchange schedules between Austria and Germany and between Austria and Switzerland use a 15 minute time period. We welcome the idea of applying a 15 minute MTU in all control blocks and for all schedules. This is an important step towards the harmonisation of market rules.

Oesterreichs Energie

Oesterreichs Energie welcomes the idea of moving towards a 15 minute MTU for internal and cross-border energy exchanges in all control blocks. In Austria and Germany, we have already had a positive experience with an MTU of 15 minutes. The exchange schedules between Austria and Germany and between Austria and Switzerland use a 15 minute period. We welcome the idea of applying the 15 minute MTU in all control blocks and for all schedules. This is an important step towards the harmonisation of market rules.

CEZ, a.s.

We support a step-by-step implementation of a 15 min ISP and a related change of MTU by 2025, as stipulated by the electricity regulation and electricity balancing guidelines. However, this is on the condition that the coupling algorithms can withstand the additional complexity of this new feature. Furthermore, until a 15 mins ISP is introduced everywhere, cross-border transmission capacity in day-ahead and intraday can only be provided according to the longest ISP on the two sides of a given border.

Any change to shorter MTUs impact generators – both positively and negatively. Therefore, they should be given sufficient time to implement such changes.

We warn against shorter deadlines for MTU implementation – MTU should always reflect ISP.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

BDEW clearly welcomes the proposal to move towards a 15 minute MTU for internal and cross border energy exchanges in all control blocks and for all schedules. As also stated in the report, the German market shows the positive impacts of a 15 minute MTU on frequency deviations.

Given that the ISP is already mandatory set for 15 minutes from 2025 onwards the shift to a 15 minute MTU seems obvious. In addition, it should be the first measure taken to reduce frequency deviations as an important step towards the harmonisation of market rules.

EUGINE – European Engine Power Plants Association

It is neither a positive nor negative impact for the turbine or engine businesses, but our technologies can potentially have a positive impact to on the grid. The 15 minute market time can, in some conditions, make the best use of the MW/min ramping capability of the generating units.

Norsk Hydro ASA (Hydro)

We would support the implementation of a 15 min time resolution. A reasonable timeline for implementing this would, however, be dependent on the number of market participants affected. It should be considered whether 15-minute ISP first should be implemented only for parties above a certain capacity, or whether it is considered cost-efficient to include all at once. Furthermore, we expect details on the solution and the transition process to be duly consulted by each respective NRA. It is imperative to ensure sufficient time for adaptions in all systems, procedures, routines, possible meter replacements, etc., by all market participants.

TIWAG-Tiroler Wasserkraft AG

We welcome the idea of moving towards a 15 minute MTU for internal and cross-border energy exchanges in all control blocks. In Austria and Germany, we have already had a positive experience with an MTU of 15 minutes. The exchange schedules between Austria and Germany and between Austria and Switzerland use a 15 minute period. We welcome the idea of applying the 15 minute MTU in all control blocks and for all schedules. This is an important step towards the harmonisation of market rules. The harmonisation of the nomination period will also facilitate the scheduling process.

VGB PowerTech Essen

A shorter MTU increases market activity and enables more liquidity. This furthers the overall effort to implement more renewable capacity into the market and helps to decrease the imbalance from forecasting errors. Even though, due to increased trading actions, a more challenging market landscape is always connected with higher operational expenses, we appreciate the competitive approach.

In the context of the gradual transition towards a harmonised 15-minute ISP in Europe, whereby some TSOs will comply with the 2021 deadline while others will maintain longer ISPs for a further period of time because of exemptions and derogations, we direct the attention of ENTSO-E and the TSOs to the problem posed by the mismatch of ISPs and MTUs in different Member States: indeed, if cross-border market time units in day-ahead and intraday are reduced from one hour to 15 minutes wherever the ISP is set at 15 minutes, but maintained at one hour or 30 minutes in other places, the order books for day-ahead and intraday will be fragmented, leading to multiple day-ahead and intraday markets for each MTU. Until all ISPs in Europe are aligned – not before 2025 – cross-border transmission capacity in day-ahead and intraday can only be provided according to the longest ISP on the two sides of a given border. This means that MRC and XBID will have to deal with a variety of product granularity and transmission capacity granularity.

EnBW Energie Baden-Württemberg AG

We fully support the proposal to move towards a 15-minute MTU for internal and cross border energy exchanges in all control blocks and for all schedules. Given that a common ISP of 15 minutes has been established, the shift to a 15-minute MTU seems obvious. As an important step towards the harmonisation of market rules, this should be, in our view, the first measure to be taken to reduce frequency deviations. In fact, the report confirms that the German market shows a positive impact of a 15-minute MTU on frequency deviations.

RWE Supply & Trading GmbH

We welcome the proposal to move to a harmonised 15 minute MTU for internal and cross-border energy exchanges in all control blocks and for all schedules. As an important step towards the harmonisation of EU market rules, this should be the first measure taken to reduce frequency deviations.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

It is neither a positive nor negative impact for the turbine or engine businesses, but our technologies can potentially have a positive impact to on the grid. The 15 minute market time can, in some conditions, make the best use of the MW/min ramping capability of the generating units.

Eurelectric

First, Eurelectric wonders about the value-added of the question, given that an ISP of 15 minutes is mandatory and given the recent positions of ACER regarding MTU.

Many studies (see footnote 1 below) show that frequency spikes remain in a context of 15 minutes MTU/ISP, but with an amplitude far lower as today. Indeed, BRPs become incentivised to balance their energy on such an MTU; thus, real-time generation comes closer to real-time consumption. The report even shows the impact of 15 MTU on the behaviour of aFRR. For instance, as mentioned on page 5 in the report, it is acknowledged that the best solution is the MTU of 15 min. Without any assessment, the report affirms, however, that, in addition, as permanent or intermediate measures, the following measures can reduce the impact, and that the preferred one is imposing restrictions on market participants.

Eurelectric is opposed to unilateral constraints to market participants if it is not demonstrated that other solutions (i.e. an MTU of 15 min and the procurement of services) are not sufficient to solve the problem. Restrictions should only be measures of last resort.

We therefore want to urge TSOs to further consider the contribution of a 15 minute MTU with regard to frequency requirements in SOGL before introducing any additional constraints for market participants.

Footnote 1:

ENTSOE & Eurelectric. Deterministic frequency deviations – root causes and proposals for potential solutions. 2011.

Stuttgart. Impact of current market developments in Europe on deterministic grid frequency deviations and frequency restauration reserve demand

VGB. High Frequency Deviations within the European Power System – Origins and Proposals for Improvement. 2009

Endesa S.A.

The starting point of each country market design is different. For some countries, such as Spain the change from 1 hour to a 15 minute MTU has a significant impact on our business from an IT perspective. It implies a big investment in money and effort along the whole value chain, generators, energy management, distribution, and retail business. This has been discussed in the framework of the EB GL and the Clean Energy Package, and this is why these regulations foresee possible derogations until 1 January 2025.

eins energie in sachsen GmbH & Co. KG

As a power plant operator and storage marketer, we do not foresee any negative effects and welcome all efforts to increase frequency stability and grid stability.

Statkraft

There are only positive effects from this proposal.

As per article 8 of the Electricity Regulation 2019/943, the ISP, as well as the MTU for day-ahead and intraday products, shall be harmonised to 15 minutes by 1 January 2021, unless regulatory authorities grant a derogation or an exemption.

Statkraft would welcome the timely implementation of this requirement and expects a reluctance by regulatory authorities to grant derogations or exemptions.

Energie AG Oberösterreich Trading GmbH

We welcome the step towards a 15 minute MTU. Nevertheless, all stakeholders have to use this instrument – maybe there should be an incentive using this instrument in the beginning – to get liquid markets as soon as possible, which are necessary to benefit from the change. Without liquid markets and high available cross border capacity, the impact would be not be sufficient to contain the problem. For Austria, the national market is too small and the cross border capacity in both directions is zero for the intraday market for most of the time, so a 15 minute MTU is not sufficient. All stakeholders are encouraged to attract short-term markets, not to hinder them.

The shorter the MTU and ISP, the more successful the integration of renewables will be.

EDF

EDF believes that the 15 minute MTU will certainly improve frequency, provided it is implemented for both scheduling and exchanges. Indeed, ENTSO-E’s report points out that both exchanges and scheduling are at the origin of DFDs.

Many studies show that frequency spikes remain in a context of a 15 minute MTU/ISP but with an amplitude far lower as today. Indeed, BRPs become incentivised to balance their portfolio’s energy on such ISP, thus real-time generation comes closer to the real-time consumption.

EDF recalls that changing the ISP to 15 minutes will represent extensive work for countries who currently feature a longer ISP. For example, it has led some NRAs (e.g. France) to grant a derogation until 2025 to implement the measure, based on an analysis of the optimal timeline and by involving the stakeholders. EDF would like to underline that any change in technical or market rules requires an in-depth assessment of the effects/impacts, as well as the costs involved.

EDF encourages the assessment of the contribution of the 15 minute MTU with regard to frequency requirements in SOGL, before introducing additional constraints for market participants. For instance, ENTSO-E outlines that “the introduction of a 15 minute MTU does not completely avoid the contribution to DFDs” without further characterisation (% of time, amplitude, etc.).

EDF deems that such assessment is of the utmost importance.

EFET - European Federation of Energy Traders

As per article 8 of the Electricity Regulation 2019/943, the ISP as well as the MTU for day-ahead and intraday products shall be harmonised to 15 minutes by 1 January 2021, unless regulatory authorities grant a derogation or an exemption.

We have already expressed in the past our support for the harmonisation of ISPs to 15 minutes (See the EFET comments on the last available draft of the Electricity Balancing Guideline prior to its adoption, dated 9 March 2017 and available at: https://efet.org/Files/Documents/Downloads/EFET%20comments%20EB%20GL_09032017.pdf).

Likewise, we support the implementation of a MTU of 15 minutes in day-ahead and intraday, provided that the coupling algorithms are able to withstand the additional complexity of this new feature.

In the context of the gradual transition towards a harmonised 15-minute ISP in Europe, where some TSOs will comply with the 2021 deadline while others will maintain longer ISPs for a further period of time because of exemptions and derogations, we direct the attention of ENTSO-E and the TSOs to the problem posed by the mismatch of ISPs and MTUs in different Member States: indeed, if cross-border MTUs in day-ahead and intraday are reduced from one hour to 15 minutes wherever the ISP is set at 15 minutes, but maintained at one hour or 30 minutes in other places, the order books for day-ahead and intraday will be fragmented, leading to multiple day-ahead and intraday markets for each MTU. Until all ISPs in Europe are aligned – not before 2025 – cross-border transmission capacity in day-ahead and intraday can only be provided according to the longest ISP on the two sides of a given border. This means that MRC and XBID will have to deal with a variety of product granularity and transmission capacity granularity. If the market time unit for day-ahead and intraday markets is reduced before all coupled markets align their ISPs, it is vital that a system of cross-products matching is established to keep these markets whole and not negatively affect cross-border trading (For more detailed explanations and recommendations on this topic, see the EFET response to the ACER consultation on the NEMOs amended methodology proposal for the price coupling algorithm and the continuous trading matching algorithm, dated 15 November 2019 and available at:

https://efet.org/Files/Documents/Downloads/EFET_ACER%20consult%20algorithm_15112019.pdf).

Edison - EDF Group

Edison supports the introduction of 15 minute MTU at European level, especially in intraday markets, as an effective instrument to reinforce intraday trading by giving market participants the possibility to better balance their positions close to real time, provided that the evolution also applies to cross-border exchange schedules.

At the same time, complex products on day-ahead market are fundamental to internalise the physical constraints of market participants and to reflect the specific characteristics of some electricity markets (e.g. the existence of the PUN in Italy), so Edison believes that the implementation of a 15 minute MTU should be carefully assessed in terms of the impacts on the algorithm performance, in order to avoid a reduction of the variety of complex products on the day-ahead market and the increase of the overall calculation time.

Summary of stakeholders' answers

All stakeholders welcome moving towards a 15-min MTU, some noting the need for a stepwise implementation and for ensuring that the algorithms can continue to perform in a secure manner. It is pointed out that shorter MTUs increase market activity and more liquidity, supports the integration of Renewable Energy Sources into the markets and helps decreasing imbalances from forecasting errors. Several stakeholders stress the benefits attained in Austria and Germany after the change to 15-min MTU, including on frequency deviations.

Several stakeholders point out that moving to shorter MTUs impacts market participants, who need to be provided with sufficient time to adapt, also noting that the timeline for the implementation of a 15-min MTU should never be shorter than the ISP 15-min implementation time.

A stakeholder questions whether the ISP 15-min obligation should be required only for market participants above a certain capacity.

Several stakeholders stress that the move to 15-min MTU should be the first measure taken to reduce DFDs.

A stakeholder is opposed to unilateral constraints to market participants if it is not demonstrated that other solutions (i.e. a 15-min MTU and additional procurement of FCR) are not sufficient to solve the problem – restrictions should be last resort measures only.

Several stakeholders indicate that inconsistencies between ISP and MTU lengths should be avoided.

ENTSO-E Response

ENTSO-E acknowledges that stakeholders are in favour of an early implementation of the 15-min MTU for day-ahead, intraday and balancing markets as one of the most effective measures to reduce DFDs.

For day-ahead, ENTSO-E notes that the 15-min MTU implementation timeline may likely last until 2025 (end of derogation period). For intraday, the 15-min MTU is already available on some borders, while cross-matching will be available in the course of 2021 (allowing matching of trades based on different MTU). Therefore, the 15-min trading is to be used on the intraday time frame as requested by most stakeholders and could be a good tool to reduce frequency variations.

ENTSO-E agrees with the convergence of ISP and MTUs towards 15 min, noting that the different implementation challenges of each country (e.g. IT and metering) as well as the derogations and exemptions are to be respected.

5.4 What do you see as the main (remaining) hurdles to moving towards a 15 Minute Market Time Unit for the Intraday and Day-Ahead energy markets?

VERBUND Trading

From our perspective there is no real hurdle. It is necessary to have sufficient time to prepare and change the IT systems of each BRP. In addition, the energy exchange should establish possibilities to block orders (e.g. for 1h) for BRPs and generation companies which do not have flexible generations (e.g. thermal power plants).

We are also convinced that the change towards a 15 minute MTU is necessary for a better integration of renewable energy sources in the energy market.

Oesterreichs Energie

From our perspective, there is no real hurdle – though perhaps there is insufficient commitment in some member states. It is necessary to have sufficent time to prepare and change the IT systems of each BRP. In addition, the energy exchange should establish possibilities to block orders (e.g. for 1h) for BRPs and generation companies which do not have flexible generations (e.g. thermal power plants).

We are also convinced that the change towards a 15 minutes MTU is necessary for the better integration of renewable energy sources in the energy market.

CEZ, a.s.

Algorithm performance: at the MESC meeting of 18 December, the NEMOs indicated that the introduction of 15-minute products, combined with other changes to DA and ID market design (CORE DA and ID flow-based, different MNAs, IDAs…) will increase the complexity of the algorithm calculations and could multiply the calculation time of Euphemia by 10, for instance. The NEMOs have committed to providing more detailed assessments of how each new market design element contributes to this complexity. Thus, it will be easier to understand whether algorithm performance in DA and ID is significantly affected or not by the introduction of 15-inute products.

Non-harmonised ISPs: until all control areas in Europe have an ISP of 15 minutes, there will remain many areas where 15-minute DA and ID products are simply not an option, given that BRPs are settled on a 30 or 60-minute basis. Here we must highlight that detailed rules on the national implementation of 15 mins ISP are missing in several member states. Market participants thus cannot efficiently prepare for the new ISP and MTU reality.

Liquidity split: there is a risk of a liquidity split in cross-border trading between countries with different ISPs, until ISPs are harmonised to 15 minutes.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

BDEW does not see any hurdles to moving towards a 15 minute MTU and supports the shift. We are convinced that the change towards a 15 minute MTU is necessary for the better integration of renewable energy sources in the energy market. In addition, the energy exchange should establish possibilities to make use of block orders (e.g. for 1h) for BRPs and power supply companies which do not have flexible generations (e.g. thermal power plants).

EUGINE - European Engine Power Plants Association

The information and controls infrastructure shall adapt to the 15 minute timing. This means verifying that the information can flow back and forth through grid operator dispatch and plant owner dispatch, up to the power plant. This should impact neither gas turbine or engine technologies.

Norsk Hydro ASA (Hydro)

The time required to implement the necessary changes to administrative and IT systems, the replacement of assets where required, the change of procedures, routines, running of demonstration/ pilots, etc. A sound timeline, taking due account of relevant market participants, is therefore essential. Regulatory changes may be required.

TIWAG-Tiroler Wasserkraft AG

From our perspective, there is no real hurdle – perhaps insufficient commitment in some member states. It is necessary to have sufficient time to prepare and change the IT systems of each BRP. In addition, the energy exchange should establish possibilities to block orders (e.g. for 1h) for BRPs and generation companies which do not have flexible generations (e.g. thermal power plants).

We are convinced that the change towards a 15 minute MTU is also necessary for a better integration of renewable energy sources in the energy market.

VGB PowerTech Essen

In Germany and some other countries, the 15 minute MTU is realised.

EnBW Energie Baden-Württemberg AG

We currently see no relevant hurdles to moving towards a 15 minute MTU for Intraday. As regards the single day-ahead market coupling, an evaluation is required of whether the performance of the clearing algorithm could be a limiting factor.

RWE Supply & Trading GmbH

We do not see any hurdles with respect to the move of the MTU to 15 minutes. As the ISP will already be harmonised from 2025 onwards, harmonising the MTU seems to be the next logical step.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

The information and controls infrastructure shall adapt to the 15 minutes timing. This means verifying that the information can flow back and forth through grid operator dispatch and plant owner dispatch up to the power plant. This should not impact either gas turbine or engine technologies.

Eurelectric

- First, we would like to mention that the objective shall be to have a well and reliable functioning of market coupling as well as allowing the flexibility to offer its capabilities.
- The recent discussions around algorithm methodologies for SDAC and SIDC showed that there are huge challenges in terms of algorithm performance for the auctions, as it

increases significantly the complexity of the optimisation while the time constraints for running this optimisation remain the same.

- Eurelectric is opposed to any reduction of possibilities for market players to use complex products in the day-ahead and/or the intraday timeframe in order to accommodate this increased complexity. This would indeed be detrimental to market efficiency and hence overall welfare.
- The move to a 15 minute MTU should not be implemented at the cost of complex products which are heavily used by market participants today (cfr. ACER consultations on the algorithm methodology review, incl. SIDC and ID auctions in November 2019).
- Moreover, derogations to the 15 minute ISP can still be applied until 2025. Hence, Eurelectric wonders about the benefits brought by a 15 minute MTU for ID and DA without having it applied as ISP. As BRP is incentivised to be balanced over the ISP, the existence of a shorter MTU would be superfluous.

Endesa S.A.

At a wholesale level, once the balancing markets have moved to a 15 Minute MTU, the incremental effort to do so for the ID and DA markets is less important but, in any case, we will require time and effort to adapt our systems.

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Statkraft

No response.

Energie AG Oberösterreich Trading GmbH

Perhaps the time and the costs to change IT systems and the willingness to change are required.

EDF

EDF deems that the objectives shall be to have a reliable and well-functioning market coupling, as well to allow the flexibility to offer their capabilities.

As emphasised in ACER’s public consultation of November 2019 on the algorithm methodology review pursuant to the CACM Regulation, moving towards the 15 Minute MTY for Intraday and Day-Ahead energy markets is a huge challenge in terms of algorithm performance for the auctions, as it increases significantly the complexity of the optimisation, while time constraints for running this optimisation remain the same (and Euphemia is already currently at its limit).

However, reducing the possibility for market players to use complex products in the day-ahead and/or the intraday timeframe to accommodate this increased complexity should not be the way forward, as these products allow a more direct valuation of some flexibilities such as demand response with complex/industrial processes or based on time of use/critical peak pricing retail tariffs, or power plants with start-up/shut-down costs; removing the possibility to offer complex products in day-ahead auctions can thus be a threat for their valuation, likely to reduce their competitiveness and generate inefficient dispatch decisions.

EFET – European Federation of Energy Traders

We foresee two main hurdles:

- Algorithm performance: at the MESC meeting of 18 December, the NEMOs indicated that the introduction of 15 minute products, combined with other changes to DA and ID market design (CORE DA and ID flow-based, different MNAs, IDAs…) will increase the complexity of the algorithm calculations and could multiply the calculation time of Euphemia by 10, for instance. The NEMOs have committed to providing more detailed assessments on how each new market design element contributes to this complexity. Thus it will be easier to understand whether algorithm performance in DA and ID is significantly affected or not by the introduction of 15 minute products.
- Non-harmonised ISPs: until all control areas in Europe have an ISP of 15 minutes, there will remain many areas where 15 minute DA and ID products are simply not an option, given that BRPs are settled on a 30 or 60 minute basis.
- Liquidity split: there is a risk of liquidity split in cross-border trading between countries with different ISPs, until ISPs are harmonised to 15 minutes – see our response to Q3.

Edison - EDF Group

As mentioned above, Edison thinks that the main hurdles to moving towards a 15 Minute MTU could be the increase of computational complexity of the Day-Ahead coupling algorithm, which may be incompatible with the time constraints for running the optimisation.

Moreover, Edison wishes to highlight that any change in technical or market rules requires an in-depth cost benefit analysis (CBA), considering the effects on all the stakeholders involved.

Summary of stakeholders' answers

Stakeholders express the following main hurdles when moving to 15-min MTUs:

- Sufficient time should be provided to prepare and change the IT systems of each BRPs, replacement of assets where needed, change of procedures, routines, etc.
- The energy exchange should establish possibilities to block orders (e.g. for 1h) for BRPs and generation company which do not have flexible generations (e.g. thermal power plants).
- The commitment of some member states should increase. Detailed national implementation plans to move ISP to 15 min are missing in several countries.
- Algorithm performance risks. Opposition to reducing possibilities for market players to use complex products to tackle increased complexity.
- Split of liquidity in cross-border trading between countries with different ISPs.

ENTSO-E Response

ENTSO-E acknowledges the stakeholders' identified main hurdles regarding the harmonisation of the MTU to 15 minutes at both day-ahead and intraday markets. ENTSO-E agrees that sufficient time for national implementation should be provided and notes the derogation processes discussed between TSOs, market players and NRAs at the national level should accommodate the local complexities. ENTSO-E takes note of stakeholders' concerns on the performance of the day-ahead algorithm when moving to 15-min products; ENTSO-E and NEMOs are closely collaborating to ensure that the implementation is done in a safe manner.

Some stakeholders express that scheduling with multiple ISPs will lead to a split of the markets. ENTSO-E acknowledges the concern and notes that cross-matching is being implemented in intraday (2021), which should mitigate stakeholders' concern until the ISPs and MTU are fully harmonised to 15 minutes. Moreover, ENTSO-E supports having an implementation of the 15-min MTU in day-ahead coordinated by all countries.

5.5 One of the proposed solutions is to set requirements on ramping for Generation units. Do you have fast-acting generation units (ramping up or down in less than 5 minutes) in your portfolio?

VERBUND Trading

VERBUND has some fast acting generation units. These units are used to provide FCR (primary control reserve) and (automatic and manual) FRR (secondary and tertiary control reserve). A ramp rate on unit base would be in conflict with the delivery of these fast products.

Oesterreichs Energie

Oesterreichs Energie' members do have several fast acting generation units. These units provide FCR (primary control reserve) and (automatic and manual) FRR (secondary and tertiary control reserve). A ramp rate on unit base would be in conflict with the delivery of these necessary fast products.

CEZ, a.s.

Yes, we do. We believe their characteristics (speed) are most efficiently used for fast grid stabilisation.

We strongly disagree with setting up requirements on the ramping of generation units. This decreases generation efficiency and is not ecologically sustainable. In addition, new rules on aFRR and mFRR already introduce stricter ramping requirements. TSOs should not impose constraints to market participants (production, storage, demand) but should procure any services they need in a market-based manner. Slower, or more smooth ramp up and ramp down should be incentivised by market signals given by balancing platforms or the electricity market, but should not disable the participation of these sources in these markets.

Moreover, SOGL does not favour generation over consumption ramping; we are concerned about the alignment of the report's proposal with general EU principles.

We also disagree with the tendency to monitor and penalise deviations from a certain ramping behaviour. As stated in our general comment, deviations are caused by several circumstances; ramping behaviour is only one of them.

EUGINE – European Engine Power Plants Association

Yes – various technologies are available. Fast ramp for big units could be challenging if emission controls are respected during transient condition, otherwise the requirement can be fulfilled.

Norsk Hydro ASA (Hydro)

Not in the Continental Europe region.

TIWAG-Tiroler Wasserkraft AG

We have several fast acting generation units in our portfolio. These units provide frequency containment reserve (primary control reserve) and (automatic and manual) FRR (secondary and tertiary control reserve). A ramp rate on unit base would be in conflict with the delivery of these necessary fast products.

VGB PowerTech Essen

Members of our association have fast-acting generation units, in particular pumped and storage hydro (high pressure, Pelton or Francis-turbines) and Li-Batteries. Thermal assets are not excluded.

EnBW Energie Baden-Württemberg AG

The generation portfolio of EnBW has a large share of pump storage units with high ramping rates.

RWE Supply & Trading GmbH

Yes

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Yes – various technologies are available. A fast ramp for big units could be challenging if emission controls are respected during transient condition, otherwise the requirement can be fulfilled.

Eurelectric

As an association, Eurelectric does not own nor operate a portfolio, but Eurelectric members do own and operate fast-acting generation units. As SOGL does not favour generation over consumption ramping, Eurelectric is concerned about the alignment of the report's proposal with general EU principles.

The ramping of generation units is the complex result of many inputs, both technical and environmental. Therefore, requirements on ramping could be difficult or impossible to implement and, if possible, they are costly.

As mentioned in question 3, Eurelectric is opposed to new/additional constraints imposed on generators.

Endesa S.A.

Hydraulic units, pumping units, PHV and windmills.

Statkraft

Yes, Statkraft has several flexible assets.

Energie AG Oberösterreich Trading GmbH

Yes, we have. We use them to participate in the FCR and aFRR market, where fast reacting units are required.

EDF

EDF owns and operates fast-acting generation units and, depending on the definition, both hydraulic and thermal units could be defined as "fast-acting". EDF wonders whether the definition of "fast-acting" generation units is appropriate, regardless of the impact in terms of power involved (MW). EDF deems that the speed of such assets is beneficial to TSOs for system operation and that they should not be summarised as a mere source of DFDs. As SOGL does not favour generation over consumption ramping, EDF is concerned about the alignment of the report's proposal with general EU principles.

Finally, regarding some assets, EDF would like to point out that an asset is likely to have a single unique ramping rate, i.e. for those assets for which a new (slower) ramp is settled, this would lead to the impossibility of using the previous ramping (which was quicker). We recall that the quick ramping of generation units has proved to be useful during alert/emergency situations in the past (e.g. the 2006 blackout). Therefore, TSOs should consider this when they assess ramping limitations.

EFET – European Federation of Energy Traders

As a representative organisation, EFET itself does not own or operate generation units.

Generally, solutions to reduce DFDs should not result in the imposition of new ramping constraints for market participants (be they generation, storage or demand asset operators/contract holders). TSOs should, rather, investigate incentives for market participants to better match their needs, or, where need be, procure the necessary services in a market-based manner.

Edison - EDF Group

Edison owns and runs both hydroelectric and thermal units which could be defined, with regards to the mere ramping time, as “fast acting” units, but Edison points out that the quickness of a ramping unit and so the derived “fast acting” definition should be assessed by considering the power involved (MW) in addition to the time spent.

In addition, Edison deems that fast-acting generation units are valuable to TSOs for system operation, so they should not be merely considered as a source of DFDs. That said, for some power plants, a change of configuration of the ramping rate can be costly. Therefore, if a change of the ramping rate is imposed (slower or again higher), a remuneration mechanism should be introduced.

Summary of stakeholders’ answers

Several stakeholders confirm power plants’ ability to perform ramping, noting, however, that these ramping limitations could conflict with the delivery of fast acting reserves such as aFRR and mFRR.

Some stakeholders strongly disagree with setting up requirements on ramping of generation units: this decreases generation efficiency and is not ecologically sustainable. In addition, new rules on aFRR and mFRR already introduce stricter ramping requirements. Stakeholders state that TSOs should not impose constraints on market participants (production, storage, demand), but they should procure any services they need in a market-based approach.

Eurelectric further states that it is opposed to new/additional constraints imposed on generators.

Several stakeholders suggest that fast-acting generation units could be beneficial to the reduction of DFDs if they are used in the current manner. Therefore, instead of seeing them as a source of DFD, they should be envisaged as a solution. This means that the fast-acting units need to be coordinated to manage frequency deviations.

ENTSO-E Response

The ramping request was identified as one of the different measures for ensuring a secure operation of the interconnected Continental European system. The ramping is only required during a change of schedule operation and does not interfere with the provision of any other ancillary services such as the related point of entry shall act in parallel and not in series with any of those services.

According to SO GL Reg. Art. 137(4) there is no difference between the obligations on either demand or generation units – the ramping requirement can be the same for both.

The ramping provision should be transparent and those market parties who follow the ramping requirements should not penalised by any other market remuneration rules. Penalisation may apply to those market parties who do not follow the ramping provision. The choice of mitigation measures will be decided by the individual TSOs, LFC blocks and their respective NRAs.

Furthermore, ENTSO-E acknowledges the view of several stakeholders in terms of considering fast-acting generation units to be more like a solution than a problem in the light of DFDs. ENTSO-E looks forward to a dialogue with market parties on how to coordinate fast-acting generation units in such a way that they contribute to the reduction of DFD.

5.6 Would you be willing to enable slower ramp up and ramp down (5 minutes or more) of these fast-acting generation units? What would you need in terms of rules or regulations?

VERBUND Trading

For the time being, a BRP has to be in balance due to the Austrian Market Rules. If a BRP uses slower ramps, the BRP will be penalised in the imbalance settlement.

If the Austrian Market roles changes and there are no financial penalties for ramps provided in the imbalance settlement, VERBUND will use ramps on the BRP-level/portfolio level (exchange schedules on BRP-level/balance group level).

We are strictly against using ramps on the generation unit level. Ramps on generation level will reduce the amount of control reserves for the TSO, increase the costs of control reserve (due to reduced reserves) and reduce the quality of FRR due to the reduced speed of the generators. In cases of outages, the time of imbalances will be longer. We are convinced that ramps for fast-acting generations have many disadvantages and will reduce the security of the whole system.

Oesterreichs Energie

For the time being, a BRP has to be in balance due to the Austrian Market Rules. If a BRP uses slower ramps, the BRP will be penalised in the imbalance settlement.

We are strictly against using ramps on the generation unit level. Ramps on the generation level will reduce the amount of control reserves for the TSO, increase the costs of control reserve (due to reduced reserves) and reduce the quality of FRRs due to the reduced speed of generation. In cases of outages, the time of imbalances will be longer. We are convinced that ramps for fast-acting generation units have many disadvantages and will reduce the security of the whole system.

Even ramps on the BRP-level/portfolio level (exchange schedules on the BRP-level/balance group level) would require an amendment of Austrian Market Rules and the guarantee that there are no financial penalties for ramps provided in the imbalance settlement.

CEZ, a.s.

No, as this would cause significant inefficiencies in their operation and for the whole system.

In general, we consider that the way DFDs are currently addressed should be modified. The report focuses on constraints and penalties instead of addressing the products/services and market-based approach. Any solution should incentivise physical response/behaviour and not be a pure financial reallocation by means of penalties (which would reallocate money). Such a “solution” should be envisaged in a well-designed market design and paid by the beneficiaries.

The report outlines that “Any financial disadvantage for the individual market participant will be compensated according to the rules of EBGL Article 18(6)(l), hence this solution should not influence market behaviour but only the physical activation”. We deem that such a principle is essential to envisage this option.

The producers involved should then evolve to a market design, in an optional manner, and should not be constrained unilaterally and without any revenue stream. In other words, that TSOs could evaluate the benefits of defining and procuring such a product in the market (rather than prescribing it to all generators).

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

BDEW clearly opposes requirements on ramping for generations and emphasises that these should only be the very last resort to reduce frequency deviations.

Furthermore, slower ramps could increase the balancing group deviations or lead to an oversteering at the end of quarter hours, which would not solve the problem, but only shift the frequency deviation from the beginning towards the end of the period (Fig. 27 in the Report on Deterministic Frequency Deviations).

In addition, a unit based ramp rate on fast-active generation units would be in conflict with the portfolio based optimisation and delivery of these units.

EUGINE - European Engine Power Plants Association

Yes **–** in principle it is possible to set a slow ramp on unit with high MW/min ramping capability. This does not require capital costs; the solution is to upgrade the plant or unit controller. Regarding regulation, a clear requirement on remotely setting the units ramp rate within a technically possible range would have a positive impact.

Norsk Hydro ASA (Hydro)

N/A – see our comments to number 5.

TIWAG-Tiroler Wasserkraft AG

We clearly oppose requirements on ramping for generations and emphasises that these should only be the very last resort to reduce frequency deviations.

Furthermore, slower ramps could increase the balancing group deviations or lead to an oversteering at the end of quarter hours, which would not solve the problem but only shift the frequency deviation from the beginning towards the end of the period (Fig. 27 in the Report on Deterministic Frequency Deviations).

In addition, a unit based ramp rate on fast-active generation units would be in conflict with the portfolio based optimisation and delivery of these units.

VGB PowerTech Essen

In addition to technical restraints which can be addressed by modified control systems, the slower ramping would decrease the high flexibility potential of fast-acting assets. In anticipation of future energy systems, it does not seem wise to reduce requirements to a level which is mainly driven by conventional thermal assets.

This question is somewhat misleading. The schedule business is binding for the fulfilment of the production task. The timetable has to be fulfilled and the power plant must adhere to it as precisely as possible. If this is not done, a deviation arises which is known as the balancing group deviation. This balancing group deviation is and must be paid separately. (More recently, stricter rules have been drawn up:

https://www.bundesnetzagentur.de/DE/Service-Funktionen/Beschlusskammern/1_GZ/BK6-GZ/2019/BK6-19-212_217_218/BK6-19-212_217_218_Aktuelles.html?nn=869698

such as

https://www.regelleistung.net/ext/static/rebap

Regulation rules have to be adjusted to earn the conversion costs back!)

EnBW Energie Baden-Württemberg AG

In our view, it is important that neither existing fast-ramping units are disadvantaged, nor any investments in new fast-ramping units are discouraged. It is important to recognise that these units are indispensable as regards to other aspects of system security balancing and renewable integration.

RWE Supply & Trading GmbH

No. We strongly oppose any requirements or restrictions on ramping for generation units. Especially in times where the value of flexible generation is developing and will heavily depend on whether system operators communicate their needs in an open and transparent manner, the markets' ability to respond to such needs should not be suppressed.

In addition, we would like to highlight that a unit based ramp rate on fast-active generation units would be in conflict with the portfolio based optimisation and dispatch of these units.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Yes – in principle it is possible to set a slow ramp on unit with high MW/min ramping capability. This does not require capital costs; the solution is to upgrade the plant or unit controller. Regarding regulation, a clear requirement on remotely setting the units ramp rate within a technically possible range would have a positive impact.

Eurelectric

Eurelectric considers that the way DFDs are currently addressed should be modified. The report focuses on constraints and penalties instead of addressing products/services and market based approach.

Any solution shall incentivise physical response/behavior and not be a pure financial reallocation by means of penalties (which would reallocate money). Such a "solution" should be envisaged in a well-designed market design and paid by the beneficiaries.

The report outlines that "Any financial disadvantage for the individual market participant will be compensated according to the rules of EBGL Article 18(6)(l), hence this solution should not influence market behavior but only the physical activation".

Eurelectric deems that such a principle is essential to envisage such an option.

Producers involved should then evolve in a market design, in an optional manner, and not be constrained unilaterally and without any revenue stream. In other words, TSOs could evaluate the benefits of defining and procuring such a (5/10min) product in the market (rather than prescribing it to all generators).

Endesa S.A.

In Spain, we do not think this is necessary. As stated in the ENTSOE's Consultation "Report on Deterministic Frequency " on 4 November 2019, the aFRR provision is done at a 'regulating area' level (portfolio) that guarantees that, regardless of the possible technical restrictions of certain individual units, the joint provision always complies with the LFC requirement. We fully agree that this has resulted in a very good functioning of aFRR provision in the Spanish system and thus in small DFDs, so we will support this robust and proven solution in the Spanish market. Note that, in Spain, aFRR FAT is 5 minutes; that is, this portfolio solution is able to provide the quickest response required in Europe.

Eins Energie in Sachsen GmbH & Co. KG

Eins clearly opposes requirements on ramping for generations and emphasises that these should only be the very last resort to reduce frequency deviations.

Furthermore, slower ramps could increase the balancing group deviations or lead to an oversteering at the end of quarter hours, which would not solve the problem but only shift the frequency deviation from the beginning towards the end of the period (Fig. 27 in Report on Deterministic Frequency Deviations).

In addition, a unit based ramp rate on fast-active generation units would be in conflict with the portfolio based optimisation and delivery of these units.

Statkraft

Slower – or smoother – ramp up and ramp down should be incentivised by market signals or should be compensated. The perfect solution would be a further reduction of the ISP. However, that solution seems unrealistic in the short and medium term.

Energie AG Oberösterreich Trading GmbH

No. In our opinion, fast-acting generation units are necessary to avoid DFDs and are of particular value to the TSO. It makes no sense for us to reduce the speed of generation units and to discuss at the same time promoting batteries. However, market rules have to be changed to use fast-acting generation units to reduce DFDs without penalties in a much more efficient manner.

EDF

EDF wants to stress that any solution shall incentivise physical response/behavior and not be a pure financial reallocation by means of penalties (which would only reallocate money).

Ramping of generation units is the complex result of both technical issues and environmental issues. Requirements on ramping on "fast-acting generation" could be difficult or impossible to implement. When possible, they could be envisaged only in a subset of assets (for example by spreading the start and go of units – see question 7). However, the current energy market design (Balancing and Energy mainly) does not incentive such behavior and actually penalises a market participant able to do so. Therefore, such a "solution" would actually be a service which should be envisaged in a market-based approach and paid for by the beneficiaries. The producers involved should then evolve in a well-designed market, in an optional manner, and not be constrained unilaterally and without any revenue stream.

The report outlines that "Any financial disadvantage for the individual market participant will be compensated according to the rules of EBGL Article 18(6)(l), hence this solution should not influence market behavior but only the physical activation".

EDF deems that such a principle is essential to envisage such an option. The generators involved should not be hindered from offering on Balancing Markets and be compensated whenever applicable. TSO should thus a) adapt the controls to be made, b) allow the participation in Balancing Platforms for those units, and c) ensure that compensations reflect economic losses for market participants.

EFET – European Federation of Energy Traders

If the need of the TSOs is for slower ramping up and ramp down, the appropriate market signals should be developed to incentivise market participants. A further reduction of the ISP could be investigated.

Edison – EDF Group

Edison considers that the current energy market design does not offer operators any incentive to change their ramping configurations, whereas the imbalance settlement mechanisms discourage generation unit owners from slowing ramps until shifting injection schedules to the immediate previous/successive ISP.

Edison thinks that slower ramp up and down should be considered by TSOs as a new ancillary service to be procured in a well-designed market with an adequate remuneration for generators who decide to provide this service (which should remain optional).

Summary of stakeholders' answers

Several stakeholders note that ramps for fast-acting generations have many disadvantages and will reduce the security of the whole system. Stakeholders state that slower ramps could increase the balancing group deviations or lead to an oversteering at the end of quarter hours, which would not solve the problem, but only shift the frequency deviation from the beginning towards the end of the period. However, as stated by stakeholders, if national balancing market rules are adapted and there are no financial penalties for ramps provided in the imbalance settlement ramps, such ramps could be used on the BRP portfolio level.

Stakeholders state that the generators involved should not be hindered from offering on the balancing markets and should be compensated whenever applicable. TSO should thus a) adapt the controls to be made, b) allow the participation in balancing platforms of those units and c) ensure that compensation reflects economic losses for market participants.

It is suggested by stakeholders that any solution should incentivise physical response and behaviour in a well-designed market which is paid for by the beneficiaries. The producers involved should then participate in a market design improvement process, in an optional manner, so that TSOs can evaluate the benefits of defining and procuring such a product in the market.

Especially in times where the value of flexible generation is developing and will heavily depend on whether system operators communicate their needs in an open and transparent manner, the markets' ability to respond to such needs should not be suppressed.

It is also noted by stakeholders that slower ramping would decrease the high flexibility of fast-acting assets. In anticipation of future energy systems, it does not seem wise to reduce requirements to a level which is mainly driven by conventional thermal assets.

In general, the comments from stakeholders suggest using the fast acting units to reduce frequency variations, by coordinating them in such a manner that they act to stabilise the frequency rather than requesting fast units to slower their ramping.

ENTSO-E Response

ENTSO-E notes the strong opinion of stakeholders to ramping limitations on generating units. However, this mitigation measure does have a strong impact on DFDs and does address one of the root causes of DFDs.

ENTSO-E welcomes the suggestion that additional mechanisms could be developed which will allow fast-acting units to be used in a manner that they stabilise the frequency rather than causing the DFD, as is sometimes the case (Eg, Products involving Limited Energy Reservoirs).

Currently, fast-acting units are frequently activated solely to keep an individual portfolio of a BRP balanced, and not with system security in mind. A change in mechanisms which will enable the fast-acting units to be activated to balance the frequency instead of the portfolio could be used to reduce DFDs.

5.7 An identified cause of deterministic frequency deviations is the simultaneous starting or stopping of generation units or significant load at specific moments in time, usually at the change of an hour. Would you be willing to spread start and stop of units over a longer period ? What would you need in terms of rules or regulations to be able to do this?

VERBUND Trading

VERBUND already spreads the start and stop of units at the change of an hour. If the market rules change and if there is no financial penalty for ramps on the BRP level foreseen in the imbalance settlement, VERBUND will spread the start and stop of units over an even longer period at the change of an hour.

Oesterreichs Energie

See Q 6

CEZ, a.s.

No, as stated above, any change to standard ramping of the generation source decreases its efficiency and thus impacts the environment. Besides that, we have the redispatching as a market tool to solve these kinds of issues, if there is an issue, TSOs should probably use it more extensively.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

Starting or stopping of generation is oriented towards the bidding structure of products such as e.g. 4 hour blocks, 1 hour blocks, and ¼ hour blocks. A spread in starting and stopping times would therefore have a strong impact on the operation and marketing of these units. This implies a restriction on market based decisions of how to run generation units in an economically efficient measure and respond to price signals.

Furthermore, market rules and financial penalties foreseen in the imbalance settlement as a result of ramps on the BRP level are in conflict with a spread in starting and stop-ping times.

With an increasing share of renewables, this mitigation measure might be implicitly taken, as ramping of those units does not respect 15 minute intervals.

EUGINE – European Engine Power Plants Association

Yes. This does not require capital cost; the solution could be to upgrade the plant or unit controller. Start and stop commands are received from a higher-level control not part of the specific generating unit.

Norsk Hydro ASA (Hydro)

In general, restrictions must be limited to the technical capabilities of the units. For loads, it would be imperative in general not to allow restrictions leading to major disadvantages in the process or production of goods. This should be analysed in each case based on a CBA. For production units, this should be possible within the technical capabilities of the generators. Market mechanisms which ensure said needs should be developed to the extent possible. Any market mechanism should facilitate the participation of both production units and consumption units.

TIWAG-Tiroler Wasserkraft AG

Starting or stopping of generation is oriented towards the bidding structure of products such as, e.g. 4 hour blocks, 1 hour blocks, and ¼ hour blocks. A spread in starting and stopping times would therefore have a strong impact on the operation and marketing of these units. This implies a restriction on market based decisions of how to run generation units in an economically efficient measure and respond to price signals.

Furthermore, market rules and financial penalties foreseen in the imbalance settlement as a result of ramps on the BRP level are in conflict with a spread in starting and stopping times.

With an increasing share of renewables, this mitigation measure might be implicitly taken, as ramping of those units does not respect 15 minute intervals.

VGB PowerTech Essen

The dilemma is clearly addressed in the conclusion statement to chapter 2.4. Avoiding a misuse of FCR and aFRR and anticipating that in CE 15 minute MTU and ISP will be realised to reduce DFD, the DFC will not completely disappear, because the discrepancy between "physics" (real-time dynamic of load and generation units, TSOs real-time control) and its approximation with 15 minute MTU / IPS remains.

EnBW Energie Baden-Württemberg AG

Starting or stopping of generation is oriented towards the bidding structure of products, such as e.g. 4-hour blocks, 1-hour blocks and ¼-hour blocks. A spread in starting and stopping times would therefore have a strong impact on the operation of these units. It especially affects market-based decisions to run the units in an economically efficient measure and respond to price signals. Furthermore, market rules and financial penalties foreseen in the imbalance settlement as a result of ramps on the BRP level are in conflict with a spread in starting and stopping times.

Generally, with an increasing share of renewables, this mitigation measure might be implicitly taken already, as ramping of those units does not respect 15-minute intervals.

RWE Supply & Trading GmbH

This proposal addresses the heart of the bidding structure of balancing products which are currently designed in blocks such as 4 hourly, 1 hourly or quarter hourly blocks. Spreading starting and stopping times would therefore have a very strong impact on the operation and marketing of units in these markets.

Such a solution would thus imply a restriction on market based decisions of how to run generation units in an economically efficient measure. Furthermore, it would restrict market participants from properly responding to system needs and price signals and would therefore hinder the long-term development of products and technologies to respond to such system needs.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Yes. This does not require capital cost; the solution could be to upgrade the plant or unit controller. Start and stop commands are received from a higher-level control which is not part of the specific generating unit.

Eurelectric

- At p21 in the report, EE says that the load changes are smooth. They conclude in their report that the problem is only coming from the assets.

We consider that ENTSO-E should look deeply on existing or planned levies which depend on design of Balancing Platforms. For instance, the use of mFRR scheduled activation will allow physical responses to be delayed by steps of 15 minutes. If existing or planned platforms do not resolve system operation issues and tailor-made solutions are to be retained by TSOs, TSOs should therefore assume such “solutions” are new ancillary services to be procured by the TSO by means of a market-based approach and paid by the beneficiaries. Producers that could be able to implement such “solutions” should not be constrained unilaterally and without any remuneration for the service provided.

Endesa S.A.

In Spain, the Real-Time Technical Constraints Market allows TSO to apply, in an economically efficient manner, a shift in the start or stop of pumping units. With small adjustments in the current regulation, this procedure could be used for the rest of fast-acting generation units. REE would analyse the amount of energy that needs to be shifted and reschedule the best units according to their individual bids.

Eins Energie in Sachsen GmbH & Co. KG

The starting or stopping of generation is oriented towards the bidding structure of products such as, e.g. 4 hour blocks, 1 hour blocks and ¼ hour blocks. A spread in starting and stopping times would therefore have a strong impact on the operation and marketing of these units.

This implies a restriction on market based decisions of how to run generation units in an economically efficient measure and respond to price signals.

Furthermore, market rules and financial penalties foreseen in the imbalance settlement as a result of ramps on the BRP level are in conflict with a spread in starting and stopping times.

Statkraft

See our response to Question 6. The spreading of start/stop times should be incentivised by market signals or compensated.

Energie AG Oberösterreich Trading GmbH

Yes, this makes more sense than 6. However, there should be no penalties in doing this as if it is today.

The Austrian TSO has congestion management contracts with certain (slow-acting) generation units. However, they insist on keeping the hourly schedules as precise as possible. Perhaps replacing hourly schedules with 5 minute schedules (with respect to ramping speed – slower is possible) might help to reduce DFDs.

EDF

EDF considers that any solution shall incentivise physical response/behavior and not be a pure financial reallocation by means of penalties (which would reallocate money). The same remarks apply as to question 6 regarding terms of rules or regulations.

Moreover, ENTSO-E should look deeply into existing or planned levies which depend on the design of Balancing Platforms:

1) EDF recalls that Balancing Platforms (TERRE or MARI by means of “mFRR Scheduled activation”) allow physical responses to be delayed by steps of 15 minutes.

2) An mFRR platform (MARI) could also allow a delay with a resolution of minutes by means of “Direct Activation”.

As already stated by EDF in both ENTSO-E’s and ACER’s consultations on the mFRR Implementation Framework, the principle of imposing systematic prolongation of Direct Activations (DA) may be detrimental to the volume of bids proposed on the platform, due to the underlying assets’ schedules constraints. In particular, this makes it impossible to offer in DA a shift ahead of a start-up planned in the schedule of the underlying asset. It would be preferable to let the Balancing Service Provider (BSP) choose whether he wishes such a prolongation or not, or to allow a bid to be “Direct Activable” only.

If existing or planned platforms do not resolve system operation issues and tailor-made solutions are to be retained by TSOs, TSOs should assume such “solutions” are new ancillary services to be procured by the TSO.

EFET – European Federation of Energy Traders

If spreading start and stop times of assets is identified as one of the possible solutions to reduce DFDs, it should be appropriately incentivised by market signals.

Edison – EDF Group

As highlighted in the answer to question N.6, the current energy market design does not incentivise operators to spread start and stop of generation units over a longer period, whereas imbalance settlement mechanisms discourage generation units owners from shifting injection schedules to the immediately previous/successive ISP.

Summary of stakeholders’ answers

Some stakeholders are already spreading the start and stop of units and could do even more if the market rules change and if there is no financial penalty for ramps on the BRP level foreseen in the imbalance settlement. Contrary to the slower ramping, this solution is considered by many stakeholders as sensible, but there should be no penalties in doing this for the market parties.

Other market parties are opposed and think this should be handled via a redispatching mechanism. TSOs should assume such “solutions” are new ancillary services to be procured by the TSO by means of a market-based approach and paid for by the beneficiaries.

This indeed addresses the heart of the bidding structure of balancing products which are currently designed in blocks such as 4 hourly, 1 hourly or quarter hourly blocks. Spreading starting and stopping times would therefore have a very strong impact on the operation and marketing of units in these markets.

ENTSO-E Response

ENTSO-E welcomes the response from multiple stakeholders that they are open to the idea of spreading the start and stop of fast units over a longer period of time as it addresses the root cause of DFDs. ENTSO-E agrees that any mechanism should not penalise market parties who participate, but rather there should be incentives to participate in a mechanism which would allow a reduction of instantaneous frequency variations due to too many units starting or stopping at the same time. ENTSO-E will continue to work together with market parties to investigate ways forward.

Portfolio scheduling entities could allow the easy spread of generation changes to mitigate reported loss of efficiency of very fast units due to ramping constraints. It is important that this time spreading concept would also be applied, through adequate market/regulatory incentives, to load behaviour, to mitigate for instance simultaneous load connection/disconnection carried out by automatic devices at a change of the tariff period, which also play an important role in DFDs.

5.8 One of the proposed solutions is to have ramping included in all Schedule exchanges between ISPs. What do you see as main hurdles towards implementation of such a solution?

VERBUND Trading

At the time being, a BRP is penalised in the imbalance settlement for ramping the exchange schedules. The Austrian market rules, especially the rules to calculate the imbalance settlement, have to be modified accordingly to prevent penalties for ramping.

Oesterreichs Energie

See Q 6

At the time being, a BRP is penalised in the imbalance settlement for ramping the exchange schedules. The Austrian market rules, especially the rules to calculate the imbalance settlement, would have to be amended respectively to prevent penalties for ramping.

CEZ, a.s.

We disagree with such solution.

The efficiency on constraining Schedule exchanges between ISPs has yet to be demonstrated. In some countries, the share of physical exchanges amounts to about 10% compared to the overall generation. Such constraint could induce swaps between fast units to slow units based on power dynamics and not operational expenditures (mainly fuel). This loss of overall welfare must be assessed and compared to the benefits of reducing the risk of system operation.

These solutions shall be envisaged after thorough assessment and when “no other measures are reasonably available or are sufficient to control its contribution to the DFDs “. In addition, this would require IT investments, all along the “scheduling chain”, from the BRP, to BRP-TSO communication until TSO treatment of the schedules. Such investments, if needed by the TSOs, should be compensated by the TSOs to the market participants. This will create a new constraint on the production units and optimization processes. A degree of freedom is lost. Again, a product and market-based approach should be considered instead of constraining generation units.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

Day-Ahead and Intraday markets, as well as balancing markets, are moving towards 15 minute products. Introducing additional ramps between adjacent intervals strongly inter-feres with this approach.

To better understand and assess this approach, BDEW asks for more clarification and recommends to analyse the underlying Swiss model with all stakeholders.

EUGINE - European Engine Power Plants Association

This would require information and controls system to read ramps. This appears as minor risk and complexity to adapt. The communication architecture shall be defined and the way the commands are provided are important taking into account the expected time windows considered. For example, higher level supervisory system can provide active power setting using a defined ramp rate which will be slower than the one set on the generating unit. However, in this case the expected maximum ramp rate shall be defined. It is not clear from the document how communication process is expected to work. A better and more technical answer can be provided once the way the signal exchange is planned to happen is clear.

Norsk Hydro ASA (Hydro)

No comments.

TIWAG-Tiroler Wasserkraft AG

At the time being, a BRP is penalised in the imbalance settlement for ramping the exchange schedules. The Austrian and German market rules, especially the rules to calculate the imbalance settlement, would have to be amended respectively to prevent penalties for ramping.

VGB PowerTech Essen

No forced ramps for generators / hydro pumps are acceptable.

We see an appropriate approach in increased FCR reserves.

EnBW Energie Baden-Württemberg AG

Generally, day-Ahead and intraday markets, as well as balancing markets, are already moving towards 15- minute products. Introducing additional ramps between adjacent intervals strongly interferes with this approach.

Furthermore, it remains unclear how this approach would be monitored and settled with metering based on 15-minute intervals.

EU Turbines – European Association of Gas and Steam Turbine Manufacturers

This would require information and controls system to read ramps. This appears to be a minor risk and will be complex to adapt. The communication architecture shall be defined and the way the commands are provided are important, taking into account the expected time windows considered. For example, a higher level supervisory system can provide active power setting using a defined ramp rate, which will be slower than the one set on the generating unit. However, in this case the expected maximum ramp rate shall be defined. It is not clear from the document how communication process is expected to work. A better and more technical answer can be provided once the method of the signal exchange has been clarified.

Eurelectric

- The efficiency on constraining schedule exchanges between ISPs has yet to be demonstrated.
- In some countries, the share of physical exchanges amounts to approximately 10% compared to the overall generation.
- Such constraints could induce swaps between fast units to slow units based on power dynamics and not operational expenditures (mainly fuel). This loss of overall welfare has to be assessed and compared to the benefits of reducing the risk of system operation.
- These solutions shall be envisaged after thorough assessment and when "no other measures are reasonably available or are sufficient to control its contribution to the DFDs".

- In addition, this would require IT investments, all along the “scheduling chain”, from the BRP, to BRP–TSO communication until TSO treatment of the schedules. Such investments, if required by the TSOs, should be compensated by the TSOs to the market participants.
- This will create a new constraint on the production units and optimiaation processes. A degree of freedom is lost. Again, a product and market-based approach should be considered instead of constraining generation units.

Endesa S.A.

Applying a ramping procedure to the step-wise schedules coming from the markets will always leads to certain schedules deviations (there is no perfect linearisation). Agents should be compensated, and this is quite complex.

In addition, TSO has little time to calculate these ramp schedules (the linearisation should be executed after the closing of every balancing market and the Continuous Intraday Market).

Statkraft

This solution aims to tackle the root cause of the DFDs, which is that market participants may currently be incentivised to dispatch their assets with high ramp rates to avoid any structural imbalances. The Swiss solution (labelled “adapted schedules for accounting process”, as described in section 4.1.3) aims to provide incentives to ramp smoothly.

The report has translated this Swiss solution in a solution labelled “ramping on load and generation schedules” (section 4.2.3). Although we are open to the “Swiss solution”, we have serious concerns about it, as outlined in section 4.2.3. In particular, we believe that the basic idea should be to correct or adapt schedules for settlement purposes only. It should definitely not prescribe a certain ramping behaviour. It should therefore also not aim to monitor and penalise deviations from a certain ramping behaviour. Furthermore, we believe that any solution similar to the Swiss solution should apply generally to all BRPs and should thus not distinguish between schedules from generators, consumers, suppliers or traders. It should be a generic solution.

We have no full understanding yet of the Swiss solution and its impact on the market; however, we propose that ENTSO-E should provide a more thorough analysis of the Swiss solution in cooperation with market participants and develop recommendations on this analysis.

Energie AG Oberösterreich Trading GmbH

Changing market rules – but that should work!?

EDF

The efficiency of constraining schedule exchanges between ISPs has yet to be demonstrated.

The introduction of ramping in schedules could be implemented either by modifying the underlying assets or modifying the optimisation of the schedules (without any change in individual assets dynamics); or a combination of the previous.

EDF would like to reiterate that in some countries, the share of physical exchanges is approximately 10% compared to the overall generation. Thus, constraining exchanges exclusively will only tackle a reduced part of the problem.

Secondly, such constraints will induce swaps between fast units and slow units based on power dynamics and not based on operational expenditures (mainly fuel). This loss of overall welfare has to be assessed and compared to the benefits of reducing the risk of system operation. The implementation of such solutions could have many other impacts on optimisation, from the mid to short term, and should introduce the constraints in a reliable manner (IT investments).

In any case, these solutions shall be envisaged after thorough assessment and when “no other measures are reasonably available or are sufficient to control its contribution to the DFDs”.

EFET - European Federation of Energy Traders

The question of the inclusion of ramps was extensively debated during the discussions on the establishment of the standard balancing products, and on the design of the future balancing exchange platforms. The decision was to define ramping rates but to exclude the delivery of energy during ramping from scheduled exchanges.

This solution aims to tackle the root cause of the DFDs. The root cause is that market participants may currently be incentivised to dispatch their assets with high ramp rates to avoid any structural imbalances. As noted in our answers to the two previous questions, the TSOs should seek to provide the right incentives that can serve as signals for market participants to adjust ramping to their needs.

The report presents a number of practices in various control areas. The Swiss solution (labelled “adapted schedules for accounting process” and described in section 4.1.3) caught our attention, as it aims to provide incentives for slower ramping up and down. Although we are open to investigating a “Swiss-like solution”, we have serious concerns regarding it, as outlined in section 4.2.3. In particular, we believe that the basic idea should be to correct or adapt schedules for settlement purposes only. It should definitely not prescribe a certain ramping behaviour. It should therefore not aim to monitor and penalise deviations from a certain ramping behaviour. Also we believe that any solution similar to the Swiss solution should apply generally to all BRPs and should thus not distinguish between schedules from generators, consumers, suppliers or traders. It should be a generic solution.

Like many other initiatives taken in individual control areas, we have no full understanding of the Swiss solution and its impact on the market. We therefore invite ENTSO-E to provide a more thorough analysis of this and other initiatives identified in the report. With a better understanding of each existing practice and its impact on the market, more concrete recommendations could be developed by the TSOs in cooperation with market participants.

Edison - EDF Group

Edison notes that introducing ramping constraints will generate new operational and capital expenditures (i.e. IT investments and Measurement devices) that should be adequately justified by TSOs considering the benefits expected in terms of optimal operation of the power grid. The efficiency and cost-effectiveness of constraining schedule exchanges between ISPs has yet to be demonstrated, thus an in-depth CBA on this topic is greatly needed.

Summary of stakeholders' answers

Several hurdles are expressed by stakeholders. Many stakeholders express concerns about including ramping restrictions [see below]. Others note that the harmonisation of market rules will take several years, and short-term measures need to be taken already; some stakeholders request that the Swiss solution be further investigated. The main concerns expressed by different stakeholders are listed below:

- Imbalance settlement rules need to be adapted if BRPs are penalised for ramping the exchange schedules.
- A stakeholder expresses disagreement with the proposal: the efficiency of constraining schedule exchanges between ISPs has yet to be demonstrated and could lead to the activation of units due to power dynamics and not due to operational expenditures. In addition, it would require IT investments, which the stakeholder expresses should be paid for by the TSO. The stakeholder advocates for a market-based approach instead of constraints to generation units.
- Additional ramps would interfere with the move to 15-min MTUs – a further investigation of the Swiss model should be completed.
- Such an approach would require information and control systems to read ramps; an update of the communication architecture would also be required.
- Applying ramps to the stepwise schedules will always lead to deviations; market players should be compensated.
- Although open to the Swiss solution which aims to tackle the root cause of DFDs and provide incentives to ramp smoothly, incentives should be in terms of settlement only and not ramping constraints (no monitoring and penalisation of ramping deviations). The solution should be equal to all BRPs.

ENTSO-E Response

ENTSO-E acknowledges the preference of some stakeholders to limit the scope of the ramping to settlement incentives and not physical ramps, taking note of the need for additional information and measurement systems. ENTSO-E welcomes the proposal of stakeholders to further investigate the Swiss solution.

ENTSO-E stresses that the main target for this proposed measure would be to ensure, together with other applicable measures, the stable and secure operation of the interconnected power system. ISP ramping would have to be coordinated between groups of generators and BRPs as well as with the corresponding TSOs. Moreover, ISP ramping should be considered in conjunction with related inadvertent power accounting to avoid a corresponding penalty. A special accounting procedure would apply via a simple formula to the related ramps, such that conforming ramping is incentivised.

ENTSO-E notes that the positive effect of this measure was proven by dynamic model calculations as well as a singular practical application in Switzerland. This individual measure would need to be developed in strong cooperation with all market participants and would be applied on an individual basis according to the best possible conditions for each control block.

5.9 Would the introduction of ramping in schedules lead to the slower ramping of generation units in your case? What would you need in terms of rules or regulations?

VERBUND Trading

We believe that ramping all exchange schedules on the BRP level is the best solution to solve the problem. It is important that BRPs use the same speed of the ramps of exchange schedules as TSOs. Therefore, the Austrian Market Roles must be adopted.

Oesterreichs Energie

We are not of the opinion that ramping of all exchange schedules on BRP level would solve the problem entirely; rather it would only alleviate some issues. The main cause – renewable energy, namely wind and photovoltaics – remains. Currently, renewable power plants are not capable of mitigating DFDs. In fact, fast power plants have to compensate and help instead.

CEZ, a.s.

Yes, it would cause inefficiencies and other significant issues in unit management (additional implementation cost, generation instability, investment …).

EUGINE - European Engine Power Plants Association

Yes – in principle it is possible to set a slow ramp on a unit with high MW/min ramping capability. This does not require capital cost; the solution can be to upgrade the plant or unit controller.

Proposal: Not necessarily; different ramp rates could be set depending on the type of service provided. If this slow ramp is requested, it could be remotely activated WHILE the service is being provided. In terms of regulations, clear requirements on this should be given, as well as clear methodologies to receive the activation commands.

Norsk Hydro ASA (Hydro)

No comments.

TIWAG-Tiroler Wasserkraft AG

We are not of the opinion that ramping of all exchange schedules on BRP level would solve the problem entirely; rather it would only alleviate some issues. The main cause – renewable energy, namely wind and photovoltaics – remains. Currently, renewable power plants are not capable of mitigating DFDs. In fact, fast power plants have to compensate and help instead.

VGB PowerTech Essen

A consistent approach is necessary to ensure that cross border trading is not negatively affected and the product shape is as homogenous as possible.

EnBW Energie Baden-Württemberg AG

The generation portfolio of EnBW has a large share of pump storage units with high ramping rates.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Yes – in principle it is possible to set a slow ramp on a unit with high MW/min ramping capability. This does not require capital cost; the solution can be to upgrade the plant or unit controller.

Proposal: Not necessarily; different ramp rates could be set depending on the type of service provided. If this slow ramp is requested, it could be remotely activated WHILE the service is being provided. In terms of regulations, clear requirements on this should be given, as well as clear methodologies for receiving the activation commands.

Eurelectric

The introduction of ramping in Schedules could be implemented:

- Either by modifying the underlying assets
- Either by modifying the optimisation of the schedules (without any change in assets dynamics)
- Or a combination of the previous

Even though Eurelectric members have not assessed in detail the economic impact of such introduction, they consider it would be very costly.

Eurelectric would require more clarification before giving a more firm and detailed opinion.

Endesa S.A.

See 6. In Spain, we have "regulating areas" acting in portfolio-units so we can compensate different ramps without the need for having ramping in schedules. The ramping of the portfolio-units (regulating areas) is continuously adapted to the real-time needs of the Spanish System.

Statkraft

The answer to this question will depend on the manner in which this idea is actually designed and implemented. As mentioned in our answer to question 8, we believe that the Swiss solution should first be better analysed.

Energie AG Oberösterreich Trading GmbH

It might reduce some DFDs, but this will not solve the problem. The market needs more information in real time and a change in market rules to be able to react to the changing generation of renewable energy with fast-acting generation units. Otherwise, the integration of renewable generation will exacerbate the problem.

EDF

The introduction of ramping in schedules could be implemented either by modifying the underlying assets or modifying the optimisation of the schedules (without any change in individual assets dynamics), or a combination of the previous.

The choice is to be made by each Market Participant by means of its own cost-benefit leading to the more efficient solution of the Participant. EDF is not able to provide any accurate indication, but the qualitative assessment is that it could be costly and its implementation could be long.

EFET – European Federation of Energy Traders

As a representative organisation, EFET itself does not have a portfolio of assets or contracts.

Edison – EDF Group

As highlighted in the answer to Question N.8, Edison thinks that the introduction of ramping constraints in schedules should not be imposed on generators, who should instead be able to choose whether to provide the service on the basis of their own CBA.

Summary of stakeholders' answers

The stakeholders indicate different views (both positive and negative) on the ramping in schedules measure. A summary of the remarks in relation to the introduction of ramping in schedules is listed below:

- Ramping all exchange schedules at BRP-level is the best solution; BRPs should use the same ramp rates to exchange schedules as TSOs. Austrian market rules must be adapted;
- Ramping all exchange schedules would alleviate issues but not solve the problem completely; additional fast acting power plants are necessary;
- Ramping in schedules would cause inefficiencies and other issues in unit management;
- Clear regulatory requirements are necessary;
- A consistent approach is necessary such that cross-border trading is not negatively affected;
- The introduction of ramping in schedules could be implemented by modifying the underlying assets, modifying the optimisation of the schedules or a combination of both. Such an approach would likely be expensive;
- The market requires more information in real time and a change in market rules;
- The Swiss solution should be fully analysed first;
- Ramping constraints should not be imposed on generators, but instead they should be decided based on a CBA.

ENTSO-E Response

ENTSO-E thanks stakeholders for their views on the effects of introducing ramping in schedules, and acknowledges that some stakeholders find it an extremely adequate solution for tackling DFDs. Others have concerns with regards to the need for consistent regulations and the need for changes in the underlying assets and/or schedule optimisation.

5.10 Do you see a future in having Battery Storage participating in Fast Frequency Reserves, which would help to reduce DFD? Do you have access to Battery Storage with such capability?

VERBUND Trading

VERBUND owns some batteries and works together with some owners of batteries. If there is a need for an additional product to reduce DFDs, this product should be defined in an manner that units using different technologies can provide this product. VERBUND supports the idea that a product should not depend on single technologies (e.g. batteries).

Oesterreichs Energie

A product for FFRs should be designed. Because of the fast roll-out of the renewable energy, this should be done as soon as possible and based on in-depth assessments of the consequences including cost allocation.

CEZ, a.s.

The report does not clearly identify the need for an FFR. We would welcome clarification on whether this refers to FCR or to a new type of reserve.

As a rule, there should be no discrimination between market participants in the provision of services to the TSOs. If the provider can fulfil the technical requirements laid down by the TSOs, they should be allowed to provide such services, without regard to the technology they use.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

BDEW generally welcomes a greater variety of products. As the requirements of the power grid change with a larger share of decentralised renewable generation and consumption assets, we support initiatives that address new challenges with specific products such as FFRs. The development and implementation of new products should not be restricted to one technology but be open to all technologies.

EUGINE - European Engine Power Plants Association

Although batteries can help, they appear to us not as a mandatory solution to reduce DFD. Frequency gradients, as experienced during DFD, are a couple of mHz/s, which means that the under-the-second response may not be necessary on a grid with Continental EU inertia.

Furthermore, batteries could be considered as a limited energy reservoir compared to a thermal plant, which means that holding the MW position during the ISPs will first-order impact their CAPEX.

We suggest considering controls upgrades on existing generation, assuming they have an inherent capability to provide the desired on-demand MW. This means achieving the DFD target with a potential lower total cost.

Norsk Hydro ASA (Hydro)

Batteries may play an important role as market participants in the future power system. Loads may, however, play an equally important role in today's and future markets. The sudden disconnection or reduction of loads have the same effect on the system as a sudden power injection. Loads are already present in the system. Even though the technical ability to cope with sudden disconnections or reductions may require investment, this should prove to be a cost-efficient reserve. In Norway, aluminium loads proved, during a market pilot run by the TSO in 2018, to provide reliable and accurate reserves during a frequency drop. We consider it imperative that market mechanisms are technology neutral, non-discriminating, and include various types of production units, loads, batteries, etc. It would, hence, be up to the market participants to consider the benefits of attending the markets or not.

TIWAG-Tiroler Wasserkraft AG

A product for FFRs should be designed. Because of the fast roll-out of the renewable energy, this should be done as soon as possible and based on in-depth assessments of the consequences, including cost allocation.

VGB PowerTech Essen

We would expect a reduction of DFD with a new product such as fast FCR.

EnBW Energie Baden-Württemberg AG

We generally welcome a greater variety of products. As the requirements of the power grid change to include a larger share of decentralised renewable generation and consumption assets, we support initiatives that address respective challenges with specific market products. It is important that the development and implementation of such new products should be based on the actual need of the TSO and not designed to promote specific technologies (technological neutrality).

We encourage TSOs to develop products that are specifically designed to tackle the deterministic frequency deviations, e.g. procure the intended ramping on generation schedules as a separately monitored and remunerated product. As the problem is deterministic, the resolution should also be deterministic. Furthermore, we assume that the ramp rate of a product compensating DFDs would probably not need to be exceptionally high.

RWE Supply & Trading GmbH

We do not think that the development and implementation of new products should be restricted to one technology. Instead, it should be open to all technologies. We thus support a greater variety of products in order to match the changing requirements of the power grid with a larger share of decentralised renewable generation and consumption assets.

EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Although batteries can help, they appear to us not to be a mandatory solution to reduce DFD. Frequency gradients as experience during DFD are a couple of mHz/s, which means that an under-the-second response may not be necessary on a grid with Continental EU inertia.

Furthermore, batteries could be considered as a limited energy reservoir compared to a thermal plant, which means that holding the MW position during the ISPs will first-order impact their CAPEX.

We suggest considering controls upgrades on existing generation, assuming they have an inherent capability to provide the desired on-demand MW. This means achieving the DFD target with a potential lower total cost.

Eurelectric

- The ENTSOE report does not outline a clear need for FFRs. Does the FFR refer to FCR or some new service? To allow more flexibility sources to provide fast frequency services, the participation of decentralized resources should be allowed.
- Should there be a need for a new FFR, ENTSOE should therefore assume such a "solution" to be a new service to be procured by the TSO by means of a market-based approach and paid for by the beneficiaries.
- In addition, if such a product is developed because it is deemed necessary by the TSOs, the choice of the technology should not be restricted to battery storage. As the FFRs' features have not been developed yet (and are only slightly considered in the DFD report), it is not easy to assess the question.

Endesa S.A.

Yes; battery storage would definitely help the system operation in many aspects, including the reduction of DFD.

Eins Energie in Sachsen GmbH & Co. KG

We greatly welcome the introduction of a FFR. Battery storage is ideal for an innovative and fast control product along the lines of FFR. Eins market a 10 MW battery Plant and can react to frequency changes in less than 1 second. This system could be tested in a new operating mode. Due to the complexity of the testing and introduction of a new control product, EINS does not anticipate a market launch before 2023, so short-term measures such as increasing the FCR reserves should be taken first.

Statkraft

If FFRs are implemented, then such products should be technology neutral. As a rule, there should be no discrimination between market participants in the provision of services to the TSOs. As long as an operator is able to fulfil the technical requirements laid down by the TSOs, they should be allowed to provide such services, without regard to which technology they use.

Yes, Statkraft has access to battery storage with a fast response capability.

Energie AG Oberösterreich Trading GmbH

We think that we also require battery storage to manage the integration of the increasing amount of renewables.

No, we have no access to them.

EDF

EDF has a storage plan with an objective of 10 GW by 2035. EDF is currently commissioning battery storage systems (BSS) working as a kind of FFR in isolated islands. The BSS are expected to be able to produce at full load within 400 ms after a frequency deviation (which can be set inner the automation of the BSS). In the case of the opening of a new market, EDF will most likely offer solutions for participation.

EDF considers that the ENTSO-E report does not outline a clear need on FFRs As envisaged in the report, the “short period” activation (5 minutes in the report) could allow adaptation to the energy storage. If the need was confirmed, ENTSO-E should envisage such a “solution” as a new service to be procured by the TSO, which shall therefore be envisaged in a market-based approach and paid for by the beneficiaries.

EFET - European Federation of Energy Traders

market participants to better match their needs, or, where need be, procure the necessary services in a market-based manner. So far, the report does not clearly identify the need for “Fast Frequency Reserve”.

If indeed TSOs need to procure services – beyond developing incentives for adapted ramping mentioned earlier in our response – then the procurement of such service needs to happen in a non-discriminatory, market-based manner.

We would welcome clarification on whether the concept of “Fast Frequency Reserve” refers to FCR or a new type of reserve. In any case, we welcome the participation of all actors and technologies to FFRs, including battery storage operators. As a rule, market participants or technologies should compete on an equal footing for the provision of services to the TSOs. As long as an operator is able to fulfil the technical requirements laid down by the TSOs, they should be allowed to provide such services, without regard which technology they use.

Edison - EDF Group

The technical characteristics of battery storage, which can react very quickly to frequency deviations (i.e. in the order of seconds), make these assets suitable for providing FFR services, which can also help to reduce DFD.

Edison believes that the deployment of this technology should lead to the implementation of new “Fast” reserves (such as Fast Frequency Containment Reserve), which could be required by TSOs in the near future to quickly and effectively react to frequency deviations with an increasing share of non-programmable renewable energy production.

Summary of stakeholders’ answers

A greater variety of products to support the frequency is generally welcomed by Market Parties.

A product for FFRs should be designed as an additional fast acting product to reduce DFDs. The product design should allow units using different technologies, and it should not be limited to battery storage.

As a rule, there should be no discrimination between market participants in the provision of services to the TSOs. It is important that the development and implementation of such new products should be based on the actual need of the TSO and not designed to promote specific technologies.

Energy storage, especially battery storage but also other storage technologies, are in the position to address the relevant issues related to DFD.

Next to considering batteries for fast acting reserves, Market Parties also suggest considering controller upgrades on existing generation, assuming they have an inherent capability to provide the desired on-demand MW.

In addition, loads may play an equally important role today and in future markets. The sudden disconnection or reduction of loads have the same effect on the system as a sudden power injection.

In summary, Market Parties welcome the participation of all actors and technologies in FFRs, including battery storage operators. As a rule, market participants or technologies should compete on an equal footing in the provision of TSO services. If an operator is able to fulfil the technical requirements laid down by the TSOs, they should be allowed to provide such services, regardless of the technology.

ENTSO-E Response

ENTSO-E welcomes the reactions from stakeholders and agrees that a possible solution could be to develop a fast-acting frequency response product which would be non-discriminatory and thus open to any kind of technology (not limited to battery storage). These fast-acting reserves would be one way to react to the fast frequency changes observed during DFDs. This could be an additional product in the portfolio of ancillary services which could be introduced if all other envisaged mitigation measures do not provide a sufficient way to mitigate the DFDs. In addition, it must also be noted that increasing numbers of power-electronically connected units are prequalified for FCR provision, which are already obliged by System Operation regulation to react quickly and without artificial delay to frequency changes. However, ENTSO-E notes that this mitigation measure does not address the root cause of DFDs but rather reduces the impact of DFDs. The choice of mitigation measures will be decided by the individual TSOs, LFC blocks and their respective NRAs.

5.11 Do you have any other important comments to share on the report?

VERBUND Trading

In addition, Verbund proposes to increase the amount of FCR. The report shows that there is too little FCR in some situations. To increase system security, the amount of FCR should therefore be increased.

ENTSO-E Response

In the opinion of ENTSO-E, the purpose of FCR is not to reduce DFDs but rather to act on unforeseen outages.

ENTSO-E does intend to investigate an increase of FCR related to the management of unforeseen outages, if this analysis shows a need for it.

TIWAG-Tiroler Wasserkraft AG & Oesterreichs Energie

In addition, Oesterreichs Energie strongly proposes to increase the amount of FCR. The ENTSO-E report clearly shows that there is too little FCR in some situations. Therefore, the amount of FCR has to be increased in order to increase system security.

The increasing occurrence of the DFDs and the rapid development of the "Rocof" is correlating with the roll-out of the renewable energy and the closure of large power plants. It is becoming apparent which generating technologies are responsible for the development. We strongly encourage the roll-out of the renewable energy, but it is important not to penalise power plants which are essential for their intergration. The relation between Rocof and the level of DFDs should be thoroughly analysed.

Market-based products should be designed and introduced to counteract DFDs. These products would resemble demand-side-management and give power plants and storage technology the chance to participate in this market.

Are there any investigations on the introduction of the 6x4 hours blocks/FCR?

ENTSO-E Response

In the opinion of ENTSO-E, the purpose of FCR is not to reduce DFDs but rather to act on unforeseen outages.

ENTSO-E does intend to investigate an increase of FCR related to the management of unforeseen outages if this analysis shows a need for it.

CEZ, a.s.

In general, we warn against any rash steps as a reaction to a few DFD events, some of which were not even caused by generators / market behaviour, but by issues on the TSOs' side. TSOs are responsible for addressing all issues related to secure electricity supply, including DFDs. They have a variety of tools to do so – including balancing and non-frequency ancillary services and re-dispatching. Generators provide these services based on TSOs' needs. Responsibility for events caused by DFDs thus cannot be shifted only to generators / market but need to be shared by all users of the electricity system, including TSOs and DSOs. It is surprising to read in the report that addressing DFDs by ancillary services is only mentioned as a temporary one.

Currently we are in the process of implementing 15 minute ISPs across Europe, which should be finalised until 2025. ACER also recently decided on platforms on aFRR and mFRR. We believe these processes must be implemented first; only then we can thoroughly assess their impact on DFDs and decide on consequent actions. The entry of new market players, such as aggregators and storage because of the Clean Energy Package, could also change DSDs. These changes cannot be predicted; any measures should thus be introduced only after a thorough analysis of the real impact of these new trends.

ENTSO-E Response

ENTSO-E believes it is time to address DFDs. This opinion has been shared and discussed with regulatory authorities and external stakeholders. TSOs plan to move forward nationally with the implementation of mitigation measures, but will of course endeavour to minimise the impact on the market.

ENTSO-E agrees that the implementation of a 15 minute ISP will help to reduce the hourly DFDs.

Bundesverband der Energie- und Wasserwirtschaft (BDEW)

BDEW appreciates the highly detailed analysis on deterministic frequency deviations, but does not share how the analysis of deterministic frequency deviations is addressed. The report focuses on constraints and penalties for market participants and disregards market based measures to alleviate frequency deviations.

BDEW clearly opposes market restrictions such as slower ramps and emphasises that these should only be the very last resort to reduce frequency deviations. Instead, measures should focus on the further development of already existing balancing products. Especially in Germany, a market based procurement of the “synthetic inertia” and “very fast reserve” should be established, similar to the procurement and long-term development of the FCR.

BDEW proposes the following prioritisation of market based measures:

1) Shift to a 15 Minute MTU

2) Expansion of existing balancing products

   a. Larger procurement of FCR and aFRR

3) Development of new products

   a. Market based procurement of synthetic inertia

   b. Introducing specific other products explicitly addressing DFD issues, such as very fast reserves open to all technologies

It is important that the definition of balancing products and the design of balancing markets is adapted to changes in the overall development of the energy market, such as the strong increase of renewable energy resources. Therefore, the potential to expand existing balancing products and the consideration of other alternatives should be analysed constantly.

As the overall welfare of the European energy market is paramount, an economic analysis on the impact of DFDs cannot concentrate solely on minimising services or reducing operating cost. It must focus on necessary measures to ensure that the energy economy has a cost-efficient high degree of grid stability and security of supply. Measures must not exclusively be focused on the influence of deterministic frequency deviations but must consider all aspects of significant frequency deviations.

ENTSO-E Response

ENTSO-E welcomes this analysis of possible DFD mitigation measures.

In the opinion of ENTSO-E, the purpose of FCR is not to reduce DFDs but rather to act on unforeseen outages.

ENTSO-E does intend to investigate an increase of FCR related to the management of unforeseen outages if this analysis shows a need for it.

ENTSO-E's preference is to focus on those measures which will have the lowest cost and to revert to procurement of additional reserves only when lower cost measures do not provide sufficient mitigation of DFDs.

EUGINE - European Engine Power Plants Association & EUTurbines – European Association of Gas and Steam Turbine Manufacturers

Some details are not clear from the report. We would like to know how the frequency and associated DFDs are measured in the different areas and how DFDs are detected, in terms of controllability.

Page 14: It seems that the DFDs worsened during winter time and evening. However, an evolution of the loads can be predicted (Heating system switching off at 10 pm, change of tariffs on electricity, etc.) In addition to the time change, there could be a correlation with loads and habits that can be somehow considered and smoothed in some manner.

Page 16 and 17: we much appreciated the consideration of the Gas Turbine intrinsic behavior. It has to be noted, however, that the major DFDs occurred in winter and during the night, which could be considered the best condition of operation for GT technology, and that the major power deviation occurs much far away from the FSM frequency range. On low frequency (for frequencies below 48 Hz), a natural disconnection of loads from the grid is expected to occur.

Models: it is not exactly clear which is the validation criteria used (deviation of the model from the reality, no number is provided) and if any sensitivity analysis on the assumption made was carried out. It seems that a fairly extensive and interesting work had been carried out. We are wondering if the model data are available.

As a note, the acronyms table is missing a few definitions: BRP (Balance Responsible Parties) and ISP (Imbalance Settlement Periods).

Additional FCR will result in additional requirements to be stated in the codes (FSM-2 for example with a more aggressive droop), which will then need to be implemented in the controllers of the different technologies; if this is the way forward, the time for implantation of these changes (with clear requirements) should be provided.

ENTSO-E Response

DFDs are indeed worse in winter and during the evening; A clear correlation was found between the moments of larger DFDs and the changes in schedules in the market. In addition, there is evidence of correlation with large changes in fast acting generation with the occurrence of DFDs.

The modelling of the system is performed by individual TSOs followed by TSO peer review. It is not ENTSO-E's responsibility to share the models with external parties.

Additional or alternative faster acting FCR will indeed need to be described in the relevant codes and methodologies before any procurement could be considered.

Norsk Hydro ASA (Hydro)

We would like to emphasise the necessity of European TSOs to focus properly on frequency quality and security of electricity supply as a whole. In a changing power system, this becomes more important than ever before. Mitigating measures should to the extent possible be developed through technology neutral market mechanisms, providing marketplaces for relevant participants. It is important, however, to always focus on minimising the overall system costs when introducing new measures.

ENTSO-E Response

In general, ENTSO-E agrees with this remark.

VGB PowerTech Essen

The situation whereby the FCR market is restricted by tightening technical criteria must be prevented.

ENTSO-E Response

ENTSO-E agrees with this remark.

EnBW Energie Baden-Württemberg AG

Finally, we would welcome a further evaluation of the reasons for the observed increase of DFDs. Furthermore, any intended measures should be tested against its potential impact on system security as well as on the market. In any case, market participants need to be involved before deciding upon a solution.

ENTSO-E Response

In general, ENTSO-E agrees with these remarks. ENTSO-E is setting up a monitoring of DFDs and of the effect of different mitigation measures on DFDs. Market Parties will be consulted on any mitigation measures which concerns them.

RWE Supply & Trading GmbH

Once again, we would like to stress that the solution should not be found in further market restrictions, as this would prevent market participants from developing answers to the increasing need for flexibility. Ramp restrictions on specific power plants and/or demand units would thus have far reaching effects, beyond the measures to alleviate frequency deviations.

Instead, TSOs should start a dialogue together with NEMOs, BRPs and generators in order to find market based solutions.

Furthermore, the report, as presented by Entso-E, focuses on the constraints and penalties for market participants but does not provide market-based measures to address frequency deviations.

Instead of the introduction of ramp restrictions, residual central dispatch and other market interventions, priority should be given to the following measures first:

1: Implement the harmonised 15 minute MTU

2: Expansion of existing balancing products through the larger procurement of FCR and aFRR

3: Development of new products (without restrictions on the technology used) such as the market based procurement of synthetic inertia or products addressing DFDs.

ENTSO-E Response

ENTSO-E welcomes this analysis of possible DFD mitigation measures.

ENTSO-E agrees that any market based mitigations measures need to be discussed with Market Parties. Furthermore, as stated in the conclusion, moving to a 15 minute MTU would help reduce DFDs.

ENTSO-E's preference is to focus on those measures which will have the lowest cost and to revert to the procurement of additional reserves only when lower cost measures do not provide sufficient mitigation of DFDs.

IFIEC Europe

Below is IFIEC Europe's answer to the ENTSO-e stakeholder consultation on the Deterministic Frequency Deviations report

IFIEC Europe has taken note of the problems that have arisen in the last year with respect to DFDs.

IIFIEC Europe wants to make a clear distinction between two types of DFDs. On the one hand, those that arise a.o. with the changes in programs at the hour marks. These have always existed, yet IFIEC Europe understands from the report from ENTSO-e that these are increasing due to changes in demand and supply patterns. IFIEC Europe, however, remains confident that these can be addressed with relatively minor modifications to the current market operation rules. IFIEC Europe, in any case, wants to stress that any such modifications should be taken with the minimisation of the overall system cost in mind, in order to avoid consumer invoices being unduly inflated. For IFIEC Europe, it is, moreover, important that any costs shall be attributed to those parties creating the increasing fluctuations that could lead to concerns with respect to DFDs.

On the other hand, there are the DFDs that result from errors or negligence at the level of TSOs, as can be observed with the incident in January 2019 discussed in the report at the basis of this consultation, but also with previous events concerning DFDs leading a.o. to clocks lagging behind in the European connected grid due to non-balanced energy in- and output in certain zones. For this category of DFDs, IFIEC Europe is strongly of the opinion that TSOs should check, validate and improve their internal processes as well as their collaborative mechanisms to avoid such DFDs from occurring in the future. For IFIEC Europe, the costs resulting from coping with such deterministic frequency deviations must be completely attributed to those parties, including TSOs, responsible for them and not be socialised amongst all grid users in the interconnected zone. IFIEC Europe also observes that even balancing reserves were used to cope with the observed DFDs; in general, IFIEC Europe is not opposed to safeguards to avoid real system problems because of DFDs, but is not willing to increase the cost of all grid users due to either an increase in the reserved balancing capacity and/or new costly mechanisms in order to counter a below par performance of (certain) TSOs. These issues should be addressed by the TSOs and ENTSO-e, in collaboration with the regulating authorities (if required under the auspices of the Agency and/or the European Commission and/or the Member States) and, as mentioned above, the costs should be clearly attributed under a “polluter pays” principle. Last but not least, IFIEC Europe strongly urges TSOs to analyse and validate, in collaboration with regulating authorities, their internal processes to avoid any such deterministic frequency deviations in the future

Finally, IFIEC Europe would like to emphasise the necessity of European TSOs to focus properly on frequency quality, or grid security in more general terms. In a changing power system this becomes more important than ever before. Mitigating measures should, to the extent possible, be developed through technology neutral market mechanisms, providing marketplaces for relevant participants, including industrial loads. It is important, however, to always focus on minimising the overall system costs when introducing new measures.

ENTSO-E Response

IFIEC is correct in stating that the deviation of January 2019 is only partly due to DFD but also partly due to a long-lasting frequency deviation. ENTSO-E has worked hard on the second issue and implemented considerable mitigation measures to avoid long lasting frequency deviations in the future. A further report will be published by ENTSO-E detailing the measures taken to avoid long-lasting frequency deviations.

ENTSO-E also agrees with IFIEC that all mitigation measures for DFD should be taken with the minimisation of the overall system cost in mind and to avoid consumer invoices are inflated unduly.

ENTSO-E also agrees on the necessity of European TSOs to continue to focus on frequency quality, or grid security in more general terms. In a changing power system, this becomes more important than ever before.

Eurelectric

On the main causes of DFDs (chapter 2):

The argument highlighting energy markets as a source of increased DFDs is exaggerated from our perspective, for the following reasons:

- If the hourly schedule changes and the behavior of generation units following block-shaped incentives are indeed the most important causes, the fast acting vs slow acting production units as well as the incompatibility between load ramping and block schedules (or generation ramping) have always existed and are not due to energy markets.
- The load pattern being considered as continuous fashion is a strange assumption (e.g. start-up of an arc furnace!), step-wise load pattern are a reality. Moreover, tariff incentives, for example at the switch between peak and off-peak hours, exist in some countries. These incentives induce important power peaks around the hour.

In addition, we would like to mention that the problem caused by HVDC lines is really something which should be investigated before more serious problems appear when they will be more numerous.

It is also surprising that there was no investigation done in the report about not controllable generation assets (renewables), which could also be a cause of increased DFDs.

To support this, we refer to the example of Germany DFDs' contribution examples (p.29) or the large changes in solar and wind (p.41).

We would also like to suggest that the following is further elaborated: why was there a decrease in DFDs from 2011 to 2016 (figure 3 p 11) and an increase after 2016? Even if the ENTSO-E report provides a wide view on DFDs, Eurelectric understands that ENTSO-E is unable to link the evolution of DFDs with structural/fundamental evolutions. Therefore, Eurelectric understands that TSOs' views on DFDs and its "solutions" are accompanied by an important incertitude.

As we mentioned during the MESC meeting of July 2019, it seems that the subject of frozen measurement is not addressed in the report, although it was clearly a cause of the issues on 10 January 2019. Eurelectric believes that the robustness of TSOs operation (e.g. frozen measurement) should also be among the portfolio of "solutions".

Eurelectric also wonders if the procurement of balancing capacity by blocks of 4 hours is exacerbating the issue of DFDs? Was this analysed? We recommend it be investigated.

Last but not least, we can read in the report on p.29 and p.40 that the wind turbines are creating issues at 10 pm due to noise emissions rules (it is referred to as a cause of frequency deviation): could we get more explanation and detail on this?

On the solutions addressing the root cause of DFDs (chapter 4.3):

Eurelectric considers that the solutions to address the root cause should be prioritised:

1. A 15 min MTU should be preferred as a long term solution

2. In the meantime, TSOs should opt for the procurement of services:

- Increase the volume of FCR (p5 of the report: paragraph proposed solution)
- Balancing products and/or new services: if additional services are required, their procurement and activation should be market based.
- We are surprised to read in the report (p5) that the FCR increase is considered as a temporary measure.

3. Constraints should be the last measures to be implemented, only if the others do not work

ENTSO-E Response

ENTSO-E welcomes this analysis of possible DFD mitigation measures.

ENTSO-E does not fully understand the view that the incompatibility between load ramping and block schedules (or generation ramping) has always existed and is not due to energy markets. Historically, coordinated production and transmission companies worked very closely to keep generation variations and load variations aligned on a macroscopic (country - or company-wide) level, whereas today every Market Party follows its own individual portfolio.

ENTSO-E agrees that any market based mitigations measures need to be discussed with Market Parties. Furthermore, as stated in the conclusion, moving to a 15 minute MTU would help reduce DFDs.

ENTSO-E also agrees that the problem caused by HVDC lines should be investigated further and is considering this as a further piece of work.

ENTSO-E's preference is to focus on those measures which will have the lowest cost and to revert to procurement of additional reserves only when lower cost measures do not provide sufficient mitigation of DFDs.

Eurelectric rightly points out that at some moments in the morning or the evening, simultaneous renewable start-up or shutdown could be a part of the DFD issue. Several TSOs are currently investigating this issue locally.

Eurelectric is also right in stating that the deviation of January 2019 is only partly due to DFD but also partly due to a long-lasting frequency deviation. ENTSO-E has worked hard on the second issue and implemented considerable mitigation measures to avoid long lasting frequency deviations in the future. A further report will be published by ENTSO-E detailing the measures taken to avoid long-lasting frequency deviations.

Endesa S.A.

For many years, 15 minute schedules were proposed to be a perfect solution to solve frequency deviation problems, although many agents were reluctant to implement them due to the implied IT complexity. Nowadays, countries with 15 minute schedules are facing the same or even worse DFD than before.

Frequency behavior is very complex; therefore, we should take great care before imposing changes in market regulation that would have a large cost in terms of effort, time and money, the effects of which (despite attempts at simulation) could not be assured.

We strongly defend the Spanish scheme of Regulating Areas: a portfolio of regulating and non-regulating units, fast and slow units, where each agent could decide the best way to compensate schedules and ramps while always complying with the real-time requirement of our system. We propose extending these portfolio units to include also batteries and demand units, to be able to cope with the upcoming challenges.

We also consider that another aspect that could contribute to reducing DFD is the possibility of keeping pro-rata instead of merit order activation for aFRR. In 2016, Entsoe E-bridge together with the Institute of Power Systems and Power Economics (IAEW) published a report on the "Impact of Merit Order activation of automatic Frequency Restoration Reserves and harmonised Full Activation Time". The report "concludes that pro-rata schemes have a better response than simple merit order activation schemes, especially for smaller imbalances".

In this sense, merit order is the chosen model in the EB GL, however, the EB GL foresees the possibility of amending the implementation framework of aFRR: "By eighteen months after the approval of the proposal for the implementation framework for a European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation, all TSOs may develop a proposal for modification of the European platform for the exchange of balancing energy from frequency restoration reserves with automatic activation pursuant to paragraph 1 and of the principles set in paragraph 2. Proposed modifications shall be supported by a cost-benefit analysis performed by the all TSOs pursuant to Article 61. The proposal shall be notified to the Commission". Therefore, we believe it is worth reconsidering the possibility of maintaining the pro-rata activation for aFRR.

ENTSO-E Response

ENTSO-E takes note of these remarks.

The extension of the reserve portfolio to also include batteries and demand units to be able to cope with the upcoming challenges can indeed be considered a way to mitigate DFDs.

ENTSO-E notes the proposal of using pro-rata activation of reserves instead of merit order activation of reserves as an alternative method to minimise DFDs. This would need to be considered by individual Control Block and/or countries in relation to their current and future balancing requirements (PICASSO, MARI, TERRE).

Eins Energie in Sachsen GmbH & Co. KG

Eins welcomes the initiative of ENTSO-E to increase frequency stability again and thanks it for the detailed report. We share the view that an effective method of combating DFD is to raise the FCR. We do not share the view that this is an expensive solution. Since 2016, the cost of FCR in Central Europe has fallen by up to 70%. We believe that raising the FCR will lead to overall costs comparable to those of 2016.

In addition to deterministic deviations, statistical (random) frequency deviations will also have to be compensated more frequently in the future. With the increasing installation of renewable generators and the shutdown of conventional power plants, system stability with regards to frequency maintenance can only be achieved by increasing the FCR reserves. The simulations of the ENTSO-E also allow this conclusion to be drawn. EINS warmly welcomes the idea of introducing a fast control reserve from storage facilities (like FFR in GB). Since the introduction of new control products will not be possible in the short term, EINS proposes that the increase in the FCR reserves to 5400 MW simulated by ENTSO-E be carried out on a transitional basis until 2025. With the introduction of a FFR from storage facilities from around 2022, the FCR reserve can be reduced step by step.

With the introduction of a uniform ISP of 15 minutes until 2025, the frequency reserve can potentially be adjusted should this measure have a positive effect on frequency stability.

Summary of proposals

- Increase FCR to 5400 MW by 2023
- Introduce 1000 MW FFR from 2023 and gradually reduce FCR
- Evaluate effects of the ISP introduction from 2025, adjust FCR if necessary

ENTSO-E Response

ENTSO-E welcomes this analysis of possible DFD mitigation measures.

ENTSO-E agrees that the implementation of a 15 minute ISP will help to reduce the hourly DFDs.

In the opinion of ENTSO-E, the purpose of FCR is not to reduce DFDs but rather to act on unforeseen outages.

ENTSO-E does intend to investigate an increase of FCR related to the management of unforeseen outages, if this analysis shows a need for it.

ENTSO-E's preference is to focus on those measures which will have the lowest cost and to revert to the procurement of additional reserves only when lower cost measures do not provide sufficient mitigation of DFDs.

Statkraft

System ramping restrictions on HVDC interconnectors (between the different synchronous areas), which are still being applied in the Nordic system, should be abolished. For example, a 1400 MW DC interconnector should be able to import 1400 MW in one MTU and export 1400 MW in the next MTU.

Overall, Statkraft suggests the following approach to DFDs:

1. Move towards a 15 minute MTU for internal and cross-border energy exchanges as soon as possible.

2. Analyse the Swiss solution of "adapted schedules for accounting process", consult with market participants and, if relevant, elaborate a proposal based on this Swiss solution. However, it should not impose a certain ramping behaviour. Moreover, it should not distinguish between different types of market participants. As an alternative approach, the Nordic solution could be considered, whereby the TSO asks a generator to start ramping earlier and for a longer period and then the energy imbalance caused by this early and longer ramping has to be compensated.

3. If new products or higher use of existing products (like FCR or FRR) are necessary to reduce the DFD problem further, then such products should be procured in a market-based way and should be technology neutral.

4. In any case, we dismiss the idea that TSOs would impose or require a certain ramping behaviour.

ENTSO-E Response

ENTSO-E welcomes this analysis of possible DFD mitigation measures.

We agree that the implementation of a 15 minute ISP will help to reduce the hourly DFDs and that several other mitigation measures are worth further analysis.

ENTSO-E also agrees that the problem caused by HVDC lines should be investigated further and is considering this as a further piece of work.

EDF

EDF welcomes this ENTSO-E consultation, as it provides useful analysis about DFDs and provides sound transparency. DFDs are not an issue solely for TSOs due to their impacts on all network users, thus EDF encourages ENTSOE to keep on involving stakeholders. The recent incidents (January and October) on the Continental Europe synchronous area have put the issue back high on the agenda of TSOs.

The report presents some TSO favoured solutions, mainly pushing forward additional constraints on market players, and almost no TSO measures are explored. For instance, the report outlines the merits and issues of each solution without allowing a proper comparison between solutions. An in-depth assessment of effectiveness, feasibility and economic impacts is required so as to choose and compare the most accurate and cost effective solution for the electric power system. TSOs shall be required to carry out such a comparison in a transparent manner.

EDF also agrees that a flexible approach can imply solutions that may slightly differ from one control area to the other according to local specificities, though it should not be detrimental to market players or create distortions.

EDF regrets that different subjects dealing with FCR are too often treated separately, such as dimensioning (and the possible use of probabilistic methods), time period required and reserve activation dynamics. A comprehensive and shared approach is required to to give a clear view and the right signals to the market participants.

Finally, EDF considers that the possibility of additional FCR has not been sufficiently investigated and/or quickly discarded. For instance, the report outlines a potential FFR (see question 10) and/or “specific new product with a full activation at 75 mHz”. EDF recalls that nuclear plants actually provide a positive contribution to frequency management and could participate in such products. Even if the increase of FCR will not solve the root issue of DFDs, it represents an effective lever that can be easily and rapidly implemented. The volume of FCR could be revised before other measures which could take longer to implement.

ENTSO-E Response

The proposed additional measures in this report are non-exhaustive. Any control block or country in discussion with its stakeholders and regulatory authorities can adopt its own measures to support the reduction of DFDs. Adopted measures will be considered after further TSO analysis and consultation if legally required or deemed necessary by the TSO and/or its national regulatory authority.

In the opinion of ENTSO-E, the purpose of FCR is not to reduce DFDs but rather to act on unforeseen outages.

ENTSO-E does intend to investigate an increase of FCR related to the management of unforeseen outages if this analysis shows a need for it.

ENTSO-E’s preference is to focus on those measures which will have the lowest cost and to revert to the procurement of additional reserves only when lower cost measures do not provide sufficient mitigation of DFDs.

EFET – European Federation of Energy Traders

General Introduction:

We thank ENTSO-E for giving us the opportunity to comment on their work on DFDs. This comprises both the report on the January 2019 frequency deviations in Continental Europe dated April 2019 and the report on DFDs dated November 2019 .

As noted in the introduction to the consultation, the November report was drawn up as a follow-up to the recommendations and actions of the April report. Like other market participant

representatives (See notably the Eurelectric presentation on the April report of ENTSO-E at the MESC meeting of 2 July 2019, available at:
https://docstore.entsoe.eu/_layouts/15/WopiFrame.aspx?sourcedoc=/Documents/Network%20codes%20documents/Implementation/stakeholder_committees/MESC/2019-07-02/7.0_MESC_20190702_ENTSO-E%20frequency%20deviation%20report_Eurelectric%20view_FINA.pdf&action=default), EFET was surprised by the narrative chosen by ENTSO-E with regard to the January 2019 frequency deviations. Although the main cause of the two-day frequency deviation is acknowledged to be a frozen measurement on four tie lines between Austria and Germany, the 44-page report of April dedicates only one page to the analysis and mitigation measures for such long-lasting deviations caused by measurement errors. Meanwhile, the analysis and mitigation measures for DFDs occupy 11 pages (respectively page 25 for long-lasting frequency deviations, and pages 27 to 37 for DFDs, see the report referred to in footnote 1). Likewise, three out of the five recommendations of the report concern DFDs – with detailed actions attached to each of them – whereas only two recommendations tackle measurement errors, the root cause of the January frequency deviations, with no detailed actions attached to them. Both the April and December report end up presenting the faulty measurement by the TSOs only as the second reason for the frequency deviations of January, despite daily evidence that DFDs do not cause long-lasting frequency deviations. It is important for us to set the record straight with regard to the January 2019 events, and that the responsibility (and the blame) of the incident is not shifted from system operators to the market.

As a result of the January 2019 events, we believe that an open discussion about TSOs' monitoring and control systems is required. We hope to see very soon a full detailed report – not unlike the 80-page report of December on DFDs – analysing and providing comprehensive recommendations regarding the definition and implementation of fail-safe measurement and telecommunication standards for all interconnectors values used by LFC across CE, the definition and implementation of control system functionality standards to detect "frozen" LFC values across CE, and the establishment of centralised processes and tools to facilitate the timely resolution of frequency deviation incidents by the TSOs, as laid out as recommendations in the April report.

All this being said, we welcome the comprehensive report of the TSOs and ENTSO-E on DFDs. We acknowledge the importance of the subject, especially in light of their tendency to increase over the years. We see this report as a good basis to further investigate existing practices and develop appropriate tools in order to limit DFDs in a manner that does not constrain the market.

Final comments and conclusion:

The ramping of HVDC interconnectors between synchronous areas should be reviewed. In particular, we suggest that HVDC interconnectors are ramped "fully smoothly". This means that ramping is done at the lowest ramping rate possible to ramp over the full time unit. At the same time, system ramping restrictions on HVDC interconnectors (between the different synchronous areas) that are still being applied in the Nordic system should be abolished.

Overall, EFET suggests the following approach to mitigate DFD:

1. Move towards a 15 minute MTU for internal and cross-border energy exchanges as soon as possible. Indeed, a study by ENTSO-E in 2011 highlights the clear benefits of this approach: it shows that frequency spikes remain but with a much lower amplitude than today.

2. In the meantime, TSOs should develop appropriate incentives for market participants – irrespective of technology/portfolio – to adapt ramping, without imposing a specific ramping behaviour. Best practices from individual control areas should be studied further.

3. Should incentives be insufficient, TSOs should procure the necessary ancillary services (FCR amongst others) in order to cope with frequency spikes. TSOs could also analyse further the relevance of FFR products and, if relevant, procure those in a market-based manner.

4. Introduce as slow as possible ramping (smooth ramping over the full market time unit) for HVDC interconnectors between the different synchronous areas.

We believe that the four above-mentioned actions should considerably mitigate the problem of DFDs. If new services need to be procured by TSOs, the relating products should be technology neutral.

ENTSO-E Response

ENTSO-E welcomes this analysis of possible DFD mitigation measures.

ENTSO-E agrees that the implementation of a 15 minute ISP will help to reduce the hourly DFDs and that several other mitigation measures are worth further analysis.

ENTSO-E also welcomes the proposal of providing the appropriate incentives for market participants, irrespective of technology/portfolio, to adapt ramping, without imposing a specific ramping behaviour.

ENTSO-E also agrees that the problem caused by HVDC lines should be investigated further, and is considering this as a further piece of work.

EFET is also right in stating that the deviation of January 2019 is only partly due to DFD but also partly due to a long-lasting frequency deviation. ENTSO-E has worked hard on the second issue and implemented considerable mitigation measures to avoid long lasting frequency deviations in the future. A further report will be published by ENTSO-E detailing the measures taken to avoid long-lasting frequency deviations.

Edison - EDF Group

Edison welcomes this ENTSO-E consultation, as it gives a useful insight into the problem of DFDs, but the solutions envisaged seem to be aimed at imposing additional constraints only on market players. Therefore, an in-depth assessment of the effectiveness, feasibility and economic impacts of each envisaged solution should be carried out by TSOs in a transparent manner, in order to compare different options and identify the most efficient and cost-effective solution for the power system.

Finally, as highlighted in the answers to Question N.5 and Question N.7, Edison strongly believes that the offer of new types of ancillary services related to unit ramping should remain optional for market participants. Moreover, such services should be adequately remunerated within market-based mechanisms (e.g. the ancillary services markets) to compensate for the costs incurred by market participants in changing the ramping configurations of their power plants.

ENTSO-E Response

ENTSO-E takes note of these remarks.

ACER

- The reporting on the DFDs in CE SA is too general, listing likely origins, but not attributing root causes to individual LFC blocks/areas. This prevents to identify polluters and to tackle the problems at their roots;
- According to the report, each TSO can choose his own mix of mitigation measures which could lead to different costs across the TSOs and different performances. Ramping is not completely free of charge for TSOs and, whether implemented, it would help all the synchronous area: in other words the TSOs implementing ramping would bear some costs with a benefit for all the TSOs. An even much expensive situation would occur for fast ramping products or for the increase of FCR and aFRR;
- The measures aimed at reducing the root causes of DFDs (ramping for example) should be differentiated from the measures aiming to mitigate the frequency deviations (e.g. fast ramping or FCR increase).

ENTSO-E Response

It has not been the intention of the report to focus on individual polluters, but rather to propose mitigation measures to reduce DFD. A reporting structure is being set up in such a manner that all TSOs in continental Europe will be able to follow their contribution to DFDs and their need to reduce that contribution.

We expect that all TSOs will work together to reduce DFDs, so that ultimately there are no "polluters".

ENTSO-E sees a need for sufficient measures aiming at reducing root causes of DFDs (15 minutes MTU, ramping etc) which can be complemented by the measures aiming to mitigate the frequency deviations (e.g. FCR increase). The measures aiming at reducing root causes of DFDs are detailed in section 4.3, whereas the measures to improve frequency quality are detailed in section 4.4.

6 Way Forward

6.1 Solutions which come out as preferred from analysis

Working Package 3 of the Task Force Significant Frequency Deviations' preferred solution is moving towards a 15-minute ISP and MTU, in a stepwise manner, at the national and international level and for any or all relevant timeframes. This proposal is in line with existing or upcoming legislation (Network Codes, Guidelines and Clean Energy Package) and is described in more detail in section 4.3.1 of this report.

In addition, as permanent or intermediate measures, the following solutions can reduce the impact of the DFD:

1. ramping imposed on generation units on a national level (section 4.3.3);
2. include a provision for ramping on load and generation schedules at the national level (section 4.3.2);
3. increase the volume of FCR available to control the DFD (section 4.4.1) as a temporary measure, awaiting the implementation of other solutions.

Other possible solutions which have been discussed and which could be investigated for particular control blocks could include:

(a) Introduction of a limit of change in net position of a market area / bidding zone between two successive market periods;
(b) Introduce Spot Power Balancing;
(c) Use changes between ISP for BRPs as marked based aFRR bids;
(d) Additional Very Fast Reserves from Battery Storage;
(e) Additional aFRRs;
(f) K-factor adaptation;
(g) Introduction of a Dynamic Frequency Setpoint in Control Areas / Blocks.

6.2 National implementation

Given the Market situation and that the production mix (shares of units with considerable ramping capabilities) may differ in different market areas of Member States within CE Synchronous Area, the Task Force also recommends a possible hybrid solution where different mitigation measures are implemented at the national level, depending on the specifics of each country. The goal of the hybrid solution is to reduce the level of DFDs to an acceptable level while supporting flexibility in terms of the selection of cost-effective measures within the local context.

ENTSO-E proposes to leave the decision on which solutions to mitigate the DFDs to be implemented in each LFC block, and at national level to the national TSOs and regulators. The proposed solutions in this report are not exhaustive, and any other local solutions can be proposed.

Each LFC Block must set up and follow an action plan to implement the chosen solution(s). Each LFC Block will report to ENTSO-E periodically regarding the implementation of the measures.

6.3 Setting the target

Each LFC block needs to respect the quality target as proposed in this report, Chapter 3 – acceptable DFD level of 75 mHz. Once the targets are accepted, they will be integrated into the SAFA to cover:

- The establishment of the quality targets values per LFC block;
- The measurement of the targets compliance by following instantaneous or average FRCE values;
- The mechanism by which the targets' compliance is monitored;
- The TSOs consequences for non-compliance.

6.4 Monitoring and Enforcement

ENTSO-E Regional Group Continental Europe will set up a process for monitoring the DFDs and report on a quarterly basis on all LFC Blocks' compliance level. The observed DFDs during the monitoring process are those which violate the frequency quality target as defined in Chapter 3 of this report.

The DFD monitoring process will formally start in 2021, allowing time for all LFC Blocks to implement the selected mitigation measures. A status report should be available during 2020, to follow the evolution of DFDs and FRCE quality targets before the actual start of the monitoring process.

If an LFC block is not complying with its quality target, as observed during monitoring in a specific quarterly report, it will be required to decide on an additional solution to be implemented.

6.5 Concrete action plan to tackle the DFD

The recommendations of the final report will require the implementation of at least one of the suggested solutions by 2021, with the aim to meet the quality targets set for each LFC block of CE.

Recognising the ongoing challenges in managing the system frequency, both across the hourly schedule change & during steady state operation, it is prudent to implement a comprehensive action plan to address these challenges. The proposed solutions are to be implemented progressively with all actions completed by 2021.

Each LFC Block not yet complying to the FRCE target will be required to deliver its implementation plan to the ENTSOE Regional Group Continental Europe.

In case no solutions are implemented by some LFC Blocks and the DFDs are still too high according to the targets established by the Task Force, ENTSOE Regional Europe Continental Europe could decide that these Control Blocks acquire additional FCR to assist in the reduction of DFDs until the necessary solutions are in place.

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