European Network of
Transmission System Operators
for Electricity

INITIAL FINDINGS REPORT

DETERMINISTIC FREQUENCY DEVIATIONS

2ND STAGE IMPACT ANALYSIS

VERSION 03.12.2012

AHT DETERMINISTIC FREQUENCY DEVIATIONS

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Abbreviation List

ACE	area control error
ACER	Agency for the Cooperation of Energy Regulators
AhT	ad-hoc team
BRP	balance responsible party
CACM	capacity allocation and congestion management
CE	continental Europe
CECRE	Centro de control de régimen especial, Control centre of renewable energies at REE
DFD	deterministic frequency deviation
GENCO	generation company
LFC	load frequency control
NRA	national regulatory authority
PX	power exchange
RfG	requirements for generators code
TSO	transmission system operator

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1 EXECUTIVE SUMMARY

As the first report /1/ was focused on the root causes of Deterministic Frequency Deviations (DFDs), the main target of the second report was to analyse the impact of related proposed measures.

One of the most important targets when finding appropriate measures was to propose solutions that tackle the root of the problem of deterministic frequency deviations, avoiding cost-intensive solutions which aim at mitigating the deviations when they have already occurred, such as increasing the amount of control reserves.

In a first step both the prerequisites for adequate monitoring and reporting of the causes of the frequency deviations and the related active power information of the most important interfaces were defined. As an example, it is essential that important generation units and loads are monitored with a time resolution short enough, in order to prove that their impact on the system is within the predefined limits. However, continuous and transparent monitoring and reporting is required for further quality improvements.

The working group stressed the importance of a supporting regulatory environment including the current developments of the relevant network codes. The WG opinion is that the currently available versions of the different codes are not precise enough in order to define clear limits for a precise triggering of urgently required measures for mitigating the deterministic frequency deviations.

Probabilistic calculations have shown that the market-induced imbalances and related deterministic frequency deviations result in an increased risk of needing more frequency containment reserves than available /2/. For the frequency quality level in the Continental European system during 2002, the risk of needing more than 3000 MW of frequency containment reserves is estimated at one occurrence every 32.5 years. This risk has dramatically increased during the last 9 years – together with the frequency quality worsening – so the risk for 2011 is estimated at one expected event per 20.9 years. In order to keep the risk unchanged with the present frequency quality degradation, the required increase of reserves with 120 MW would result in an increase of costs which according to the best estimations available are in the range of 31 million of Euro per year. However, this amount only includes one cost element. Other important costs are caused by the ever increasing use of control energy with additional resulting costs, but the calculation of these costs are out of the scope of this report.

The proposed measures – which could be taken within the next few years in order to tackle or decrease the DFD problem - can be grouped into three categories:

- Introduction of scheduling rules in order to improve load following. They consist in ex-ante rules such as energy-neutral adaptation of schedules for generation units or generation portfolio, or ex-post rules such as ramp-based billing.
- Development and use of specific balancing products such as schedule shifting; adaptation of schedules into ramped schedules for generation units or generation portfolio; short-duration balancing products.

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- Measures from TSO side such as the extension of the ramping period of cross-border schedules; use of specific control regimes during ramping periods or introduction of ramp restrictions on cross-border exchanges of energy.

It must be pointed out that not all measures can be (fully) introduced in every market system. Furthermore, the implementation of a forecasting process is also recommended, as it is expected to increase significantly the efficiency of some of these measures. This process should be based on a monitoring and alarming system which is able to forecast critical situations when DFD have a high probability to occur at the scale of an overall synchronous area.

A first feedback from TSOs and GenCos about the implementation effort of the several measures has shown that a few of the proposed measures are on the way to be applied within the different TSOs. Feedback from Great Britain shows that due to a different market model and behaviour there is no need in that system for further improvements related to DFD. Within the Nordic system similar frequency behaviour as in the Continental European system are observed but due to a different power-frequency control principle the corresponding measures might also differ.

The WG recommends the setup of a dedicated monitoring process with the target to report and follow the implementation of the proposed measures.

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2 INTRODUCTION

During the last few years practically all synchronous areas of ENTSO-E (as well as a few other synchronous systems in the world) have been experiencing increasing frequency variations at hour boundaries, multiple times per day, mainly during the ramping periods in the morning and in the evening. Statistics show an increase of these system frequency variations, in terms of number and amplitude. These frequency deviations have not been caused by critical events such as forced power plant or load outages. The variations with peak-to-peak values up to 150 mHz and even more are observed mainly within a time window of ten minutes centred on the change of the hour, corresponding to the standardised time interval for market schedules. These frequency deviations activate a significant integral share of the frequency containment reserve in the systems that had initially been intended and dimensioned for large generation and load outages. Consequently, they endanger the secure system operation by limiting the required control reserves for longer time periods. As consequence, an incident occurred at hour boundaries might cause a frequency deviation even larger than 200 mHz.

A EURELECTRIC & ENTSO-E joint working group analysed in a first stage the origins of the deterministic frequency deviations and made propositions for improvements. The responsible ENTSO-E bodies, namely the System Operation Committee and the Market Committee, welcomed the results and asked for a subsequent analysis of the implications of the recommendations of the resulting report /1/. All existing investigation results as well as other studies, e.g. an E-Bridge study for the Nordic system /3/, propose measures for minimizing the frequency deviations including some general principles which should also be integrated in the different network codes.

The present “Initial Findings Report” has been developed by an extended ad hoc team with additional market experts from the Market Integration and Ancillary Services Working Groups on the basis of the EURELECTRIC & ENTSO-E joint working group report and is divided into three main parts:

- Definition and discussion of solutions with regard to their applicability, interferences, cost-benefit analysis and legal/regulatory requirements.
- Analysis of monitoring and alarming needs for deterministic extraordinary frequency deviations.

Based on the present report, the implementation of several solutions may be envisaged. Furthermore, the results are used as an additional input for the Network Code drafting teams, if respective provisions in a Network Code should be necessary.

3 FRAMEWORK FOR POTENTIAL SOLUTIONS

This chapter aims at defining a general framework to classify potential solutions for the reduction of the deterministic frequency deviations given in present studies and reports. By

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means of this framework, the currently very broad discussion of manifold proposals is structured and condensed, in order to extract some **main principles** that many of the potential solutions share. These main principles form the basis for the subsequent derivation of short-term solutions and the long-term target as well as the analysis of monitoring and alarming needs. As high-level principles they are also used to develop the necessary provisions that have to be respected during the on-going drafting process of the network codes, either as direct input or as indirect criteria that should not be precluded.

All potential solutions proposed aim at an improved consistency between generation and load behaviour, in order to reduce or entirely avoid the deterministic power imbalances leading to the deterministic frequency deviations. It should be noted that the EURELECTRIC & ENTSO-E joint working group report (and other studies as well) clearly states that increasing control reserves will not solve the frequency quality problem. While this option is therefore not included in the main principles to reduce or avoid the frequency deviations, it is understood that the provision of sufficient reserves to perform load following is absolutely necessary to ensure a secure system operation.

Apparently, the desired improvement of consistency can be achieved by **three general principles,** one principle not excluding another (see **Fig. 1**):

- **Principle 1**: Stimulating BRPs to take their responsibility in terms of balancing their portfolio in the planning phase and in real-time by offering them adequate incentives and products to do so (e.g. financial incentives to remain balanced, adequate products for BRPs and sustaining the technical responsibilities in balance control e.g. using new technologies (Virtual Power Plant or smart grid solutions).

- **Principle 2:** Setting rules for scheduling, either for all BRPs or only for generators, to achieve network-friendly power output curves and avoid unduly high power steps in the schedule, where appropriate allowing for adequate financial compensation of the BRPs.

- **Principle 3:** Methods from TSO side. TSOs can and need to have the permission and appropriate tools to adjust schedules which are already nominated by BRPs, but also to elaborate on improvements that can be achieved between TSOs, without the direct involvement of BRPs. Measures to be considered are for example: (1) adapting inter-TSO scheduling and frequency control practices, (2) specific control regimes during ramping periods via control settings in LFC and/or DC-links. For the improvement of load following from TSO side, on a short timeframe, an accurate observability of the power output is needed.

Linking these common basic principles with the necessary general prerequisites leads to the framework shown in **Fig. 1**. Obviously, one prerequisite which is necessary for every potential solution is the existence of legal and regulatory support and approval of the respective measures, of course depending on the national legislation and market model.

The second important prerequisite is the implementation of a scheduling and settlement time interval on a ¼-h-basis or ramp basis, to allow for ¼-h-products where feasible in wholesale markets and balancing markets. While measures under principle 3 do not necessarily require ¼-h-scheduling and settlement intervals as an essential prerequisite, it has to be ensured that proper incentives are given for BRPs/generators to comply with schedule adjustments from TSOs and the ¼-h-intervals does benefit these incentives for BRPs and generators.

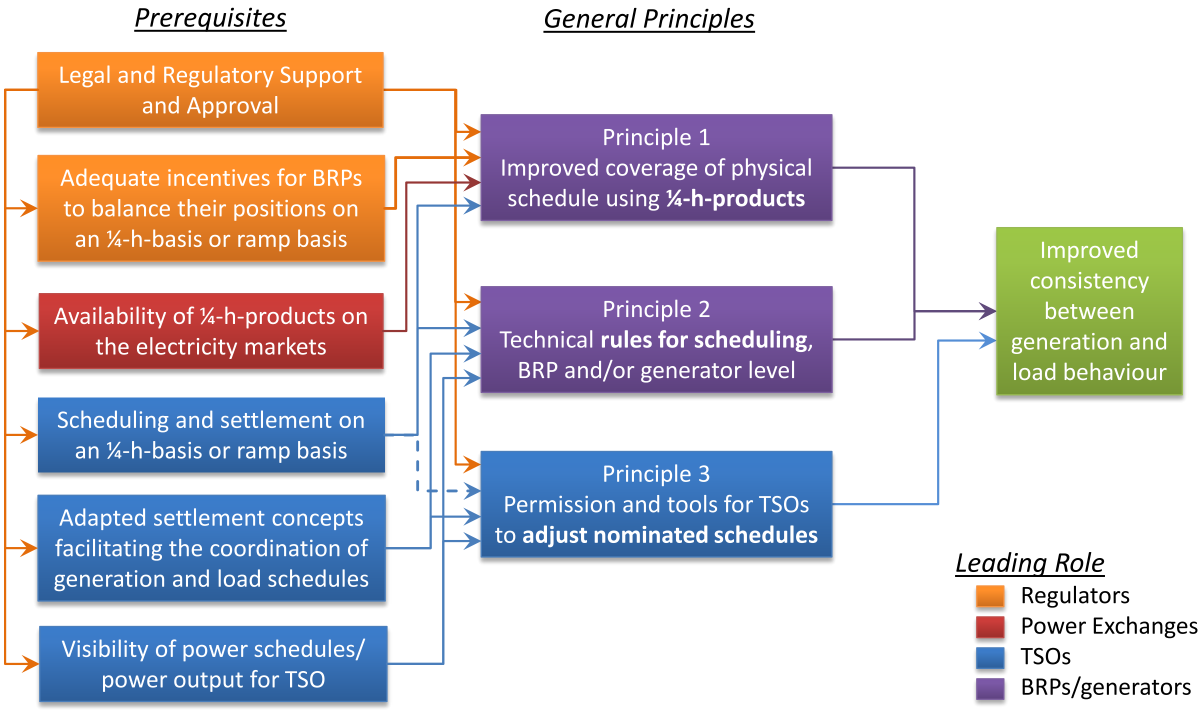

Fig. 1: **Prerequisites and general principles of the proposed solutions**

The framework shown in Fig. 1 is valid both for short-term solutions as well as for establishing the long-term target. It is obvious that neither the implementation of short-term solutions nor the long-term target can be carried out by TSOs alone, but will require stakeholder involvement and regulatory approval.

Some of these general principles have already been established and applied in several European countries as is shown in several studies and reports, e.g. /3/.

In order to address the additional risk which could be derived from the increased marked induced imbalances, the already performed by Ad-hoc Team for Operational Reserves /2/ was taken as a reference. Their probabilistic calculations have shown that the market induced imbalances and related deterministic frequency deviations result in an increased risk of needing more frequency containment reserves than available. For the frequency quality level in Continental European system during 2002, the risk of needing more than 3000 MW of frequency containment reserves is estimated as once each 32.5 years. This risk has dramatically increased during the last 9 years – together with the frequency quality worsening- so the risk for 2011 is estimated as one expected event per 20.9 years. In order to keep the risk unchanged with the present frequency quality degradation, the required increase of reserves with 120 MW would result in an increase of costs which according to the best estimations available, are in the range of 31 million of Euro per year. However, this

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amount only includes one cost element. Other important costs are caused by the ever increasing use of control energy with additional resulting costs, but the calculation of these costs are out of the scope of this report.

4 Proposed Measures

This chapter deals with measures which can be taken in a short-term timeframe to decrease the deterministic frequency deviations.

The first part of this chapter defines the input which should be given for the network codes development that is in progress today, aiming at avoiding the codes to block further measures that can be taken, in order to decrease the frequency deviations.

The second part of the chapter deals with the possible solutions that can be applied within the next few years, both from the point of view of Generation Companies (GenCos) and of TSOs. Their implications concerning the regulatory frame and their interference with the market are analysed.

In addition to the measures proposed in this chapter, and as a supplementary measure, it is recommended to implement, at the scale of an overall synchronous zone, a monitoring and alarming process which is able to forecast critical situations in which a high probability for very large deterministic frequency deviations are observed. That process is described in chapter 6, together with associated studies.

4.1 Development of the Network Codes

4.1.1 Framework Guidelines and Network Code on Capacity Allocation and Congestion Management (CACM)

Possible constraints which might result from the ACER Framework Guidelines or the Draft Network Code on Capacity Allocation and Congestion Management (CACM) have been investigated, with the result that neither the Framework Guidelines nor the Draft Network Code limits the ability to introduce a market time period of 15 minutes or products which, for example, reflected ramp rates. Especially, it is ensured that 15-minute product resolutions could be dealt with in both the day-ahead and intraday time frame by setting the respective market time period (which is not specified in the Network Code) to 15 minutes.

4.1.2 Framework Guidelines and Network Code on Electricity Balancing

The ACER Framework Guidelines on Electricity Balancing contain several relevant provisions which can be expected to directly or indirectly have a positive impact on the deterministic frequency deviations:

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With regard to incentives for BRPs to balance their position and to exchange of information:

> *5.1 General principles*
>
> *The Network Code on Electricity Balancing shall describe that the general objective of imbalance settlement in national balancing mechanisms is to ensure that BRPs support the system's balance in an efficient way and incentivise market participants in keeping and/or helping to restore the system balance.*
>
> *[…]*
>
> *5.2 Role of BRPs*
>
> *The Network Code on Electricity Balancing shall specify the role of BRPs, including the requirements specified in this section.*
>
> *All injections and withdrawals shall be covered by* ***balancing responsibility****.*
>
> *The BRPs shall meet the requirements set in the terms and conditions defined by the TSO or an entity responsible for imbalance settlement and contractually agreed upon.*
>
> *The BRPs shall provide all* ***necessary data and information*** *needed by the TSO and/or Distribution System Operator to evaluate the balancing service needs both for the planning and balance settlement purposes.*
>
> *The BRPs shall ensure the procedures for proper imbalance handling.* ***The BRPs shall be incentivised to be balanced in real time****. TSOs and NRAs may also decide to oblige BRPs to provide balanced programs in the day-ahead timeframe which may be subject to changes in intraday and to incentivise BRPs to help to restore system balance.*
>
> *The Network Code on Electricity Balancing shall impose that generation units from intermittent renewable energy sources do not receive special treatment for imbalances and have a BRP, which is financially responsible for their imbalances.*

Obviously, the responsibility for the BRPs to facilitate the maintenance of a best possible balance in real-time along with respective incentives is a core requirement of the Framework Guidelines. Furthermore, the BRPs will be obliged to provide all necessary data and information, which is a very important requirement since this is still not the case in some control areas.

With regard to time intervals for scheduling and settlement:

> *The imbalance settlement period is the time unit used for computing BRPs' imbalances. The Network Code on Electricity Balancing shall provide that it is consistent with program time unit and* ***encourage BRPs to be balanced as close to the physical reality as possible****, or help the system to restore its balance. ENTSO-E shall carry out a cost-benefit analysis on whether the imbalance settlement period shall be harmonised across Europe and report its results to the Agency.* ***The imbalance settlement period shall not exceed 30 minutes****. However, in case a TSO provides a* ***detailed cost-benefit analysis to its NRA, the NRA may decide to have a longer imbalance settlement period.***

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Thus, a scheduling and settlement time interval of 30 minutes or less has been foreseen unless a cost-benefit analysis proves the advantage of a longer settlement time interval over a shorter one. However, it has to be kept in mind, since the aggregated load e.g. within the system of Continental Europe (CE) may change by several GW during the morning and evening hours (up to around 40 GW per hour), that a short enough **settlement time interval is a crucial factor to ensure a positive effect of those measures which are based on incentives for BRP to be balanced as close as possible to the physical load.**

These provisions must be developed further during the actual drafting of the Network Code to ensure an appropriate settlement time interval with regard to system security and allow for an obligatory announcement of power schedules by generators, which are still not implemented in some countries.

Furthermore, the Framework Guidelines ask for a standardisation of balancing energy and balancing reserve products to a large extend to reach the given objectives. However, specific products can also be introduced, if “the resources from standard products would not be sufficient to balance the system, and if this does not create significant inefficiencies and distortions in national or cross-border adjacent markets. In such cases, TSOs using these specific products shall justify the existence of these products and seek the approval or fixing of the relevant NRAs.”

4.1.3 NETWORK CODE ON LOAD FREQUENCY CONTROL AND RESERVE

The current version of the Network Code on Load Frequency and Control Reserve has included as on objective the definition of *frequency quality criteria*. The expectation is that with the help of the related *frequency quality evaluation process* dedicated evaluation parameters will also highlight the systematically frequency deviations. However, the following recommendations are given for the code drafting team, in order to include related topics into the code, as transparent monitoring and reporting is one of the key challenges for increasing of the frequency quality:

Due to the ever increasing amplitude of deterministic frequency deviations observed, the following recommendations are given for the code drafting team, in order to include related topics into the code:

- Definition and evaluation criteria of deterministic frequency deviation shall be included in the ENTSO-E general glossary and NC for LF and Reserves. "*A frequency deviation is classified as deterministic if it belongs to a regularly repeating pattern within normal system operation. Currently this mainly occurs at the change of the hour."* The detailed evaluation criteria are included in **Annex 1**.

- Reporting of deterministic frequency deviations shall be included in the frequency quality reporting process as a dedicated frequency evaluation parameter. **(Monitoring of efficiency of measures proposed)** By including this new parameter within the regular reporting process the efficiency and positive impact of the application of the measures proposed can be made transparent to all market players.

4.2 DEFINITION OF MEASURES

The solutions proposed aim at improving load following as soon as possible, which makes it necessary to pay attention to the following requirements:

- No need of significant regulatory changes.

- No need of significant changes in the market.

- No need of changes in metering.

- These measures should be applicable on control area level, if needed with regional coordination.

All proposed measures require generator power output monitoring as a fundamental prerequisite.

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4.2.1 GENERATOR POWER OUTPUT MONITORING

The power output of the generators in each system should be monitored as much as possible. The quality of load-following – and thus the contribution to the frequency quality – can only be evaluated by means of the power output, even when energy schedules are divided into short timeframes. Visibility of the power performance is important to help TSOs and BRPs to take the right actions, in order to mitigate deterministic frequency deviations.

In those control areas where a real-time monitoring of the power output is already implemented, even ramped schedules could be implemented in a relatively efficient way, improving the load following and suppressing the discrete power changes that cause the deterministic frequency deviations. In those control areas without the equipment to perform real time power monitoring, some visibility of the power output of generators – in a longer timeframe, i.e. 5 minutes – would be advisable from the TSO side, to complement the energy metering and ensure an improvement in load following. Thus, in the “Requirements for Grid Connection to all Generators” Network Code as well as in the ”Operational Security” Network Code all generation units connected to the transmission system are required to provide on-line measurements of active power. However, until these Network Codes come into force, these requirements are not yet legally binding for generators and are thus not always (sufficiently) followed. TSOs can make use of control power and energy in a cost-efficient way and guarantee the system security only if they have sufficient monitoring tools of real-time power from all significant market players.

Example: France

In France, all the dispatchable generation connected to the transmission system have to send individual generation schedules (1/2 hourly programs). Non dispatchable generations (small hydro -typically<40MW-, self-generation, wind and PV generation) have to send at least generation forecast. These schedules have to be updated in intra-day in case of changes.

Concerning real time monitoring, all the new generating facilities connected to the transmission system have to send their real time active power output to RTE’s SCADA system (10 second resolution). More than 80% of the existing power plants are also monitored in real time in such a way (i.e. all dispatchable plants and big hydro run-on-the-river units). Non-monitored facilities (non-dispatchable) includes mainly small hydro stations (typically < 40 MW), and self-generation.

In France, generation scheduling monitoring enables RTE to implement a real time load monitoring that help the operator to anticipate imbalances in the system and activate balancing energy on the balancing mechanism instead of using expensive secondary reserve.

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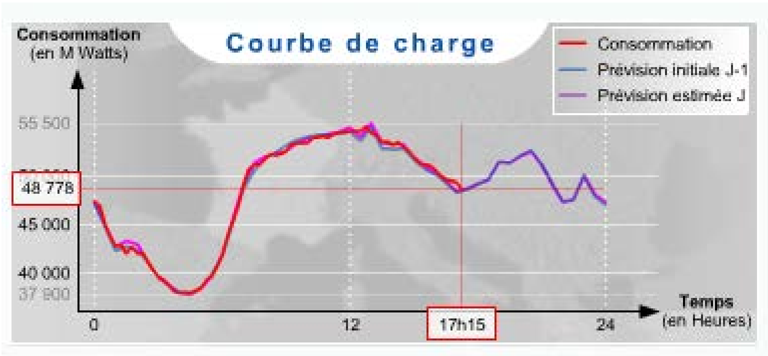

Fig 2: Real time Load Monitoring Example of September 20th at 17h15 : real time load (red colour curve); forecast (blue colour curve)

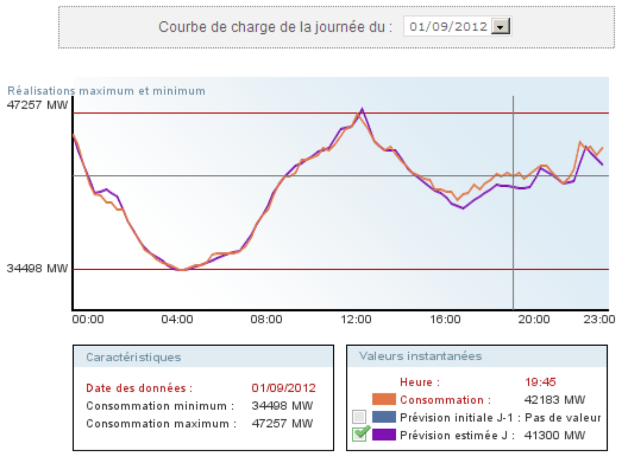

Fig. 3: **Real time Load Monitoring** - past data from September 1st : From 17h real time load (red colour) is about 900 MW above the forecast (blue colour). The operator can act on the balancing mechanism, using this information.

Furthermore, generation monitoring also enables RTE:

- To detect imbalances between actual generation and schedules, at the scale of each generating units.
- To increase the reliability of the power flow monitoring on the network (power flow state estimation).
- To monitor whether the generating units comply with the balancing orders sent by RTE.
- To monitor whether the generating units comply with their commitments in terms of primary and secondary frequency control.

Example: Spain

Spanish TSO receives information of the power output of any generating facilities with an installed power higher than 10 MW via their associated control centers. The power output information of generating facilities with installed power higher than 1 MW is received through telemetering. The resolution of the measures received must be higher than 4 seconds for the facilities that provide secondary reserve, and higher than 12 seconds for the rest. This information is integrated into the REE's Power Control Center, a specific control center dedicated to RES management (CECRE) has been working since 2006.

Aggregated power output levels are made available in real time for public information, including the disaggregation by technologies, as it can be seen in **Fig. 4**. The yellow line is the real aggregated power production, the green line is the total load forecasted by the TSO for the next hours, and the red stepped line represents the closest to real time generation schedule available. In the figure, the disaggregation of technologies and the wind power production can also be seen in the right side.

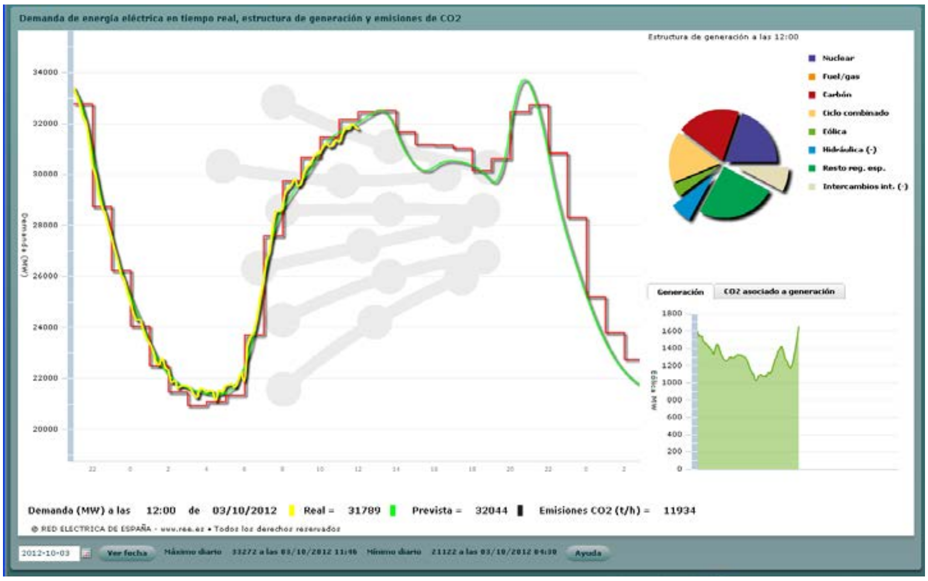

Fig. 4: Example of power output monitoring in Spain from October 3rd 2012.

Spanish TSO handles the so-called *adjustment services*, with the purpose of bringing the production schedules resulting from the day-ahead and intraday markets in line with the quality, reliability and safety requirements of the power system. Adjustment services or adjustment markets involve the overcoming of technical restrictions, the assigning of complementary services (secondary and tertiary reserves) and imbalance handling. Gate closure of intraday markets takes place around 4 hours before the real time, so further schedule adjustments are made via imbalance market and assignments of tertiary reserve. Close to the real time, REE has the possibility of re-dispatching units for security reasons or when foreseeing unbalances between the generation schedules and forecasted consumption. All RES facilities with an installed power higher than 10 MW can receive real-time orders from CECRE to curtail their production if necessary for security reasons. As the order must be followed within 15 minutes, RES can be supervised in order to permanently keep the system balanced.

Thus, power monitoring, among other essential functions, allows REE to:

- Permanently keep the Spanish system balanced, forecasting unbalances and sending the necessary orders for producers – including RES- in order to avoid them.
- Supervise the following of the orders sent to producers.

Control and supervise the provision of secondary and tertiary reserve, and monitor the amount of available reserves is in permanent use.

Example: Switzerland

After including within the Swiss Grid Code the requirement for GenCos and DSOs of following the same ramp as the TSO during the change of the hour this demand is permanently monitored by the TSO based on the related monitoring of the secondary controller output signal in combination with the monitoring of the main power plant power.

Example: Denmark

In Denmark all power plants producing 2 MW or more are monitored on-line. All power plants are required to send expected production at 5 min time resolution for at least the next 24 hours. If changes will happen, or happen, plants are required to send a new production plan immediately. Energinet.dk (the Danish TSO) monitors on-line that the plans are kept – if not the power plants are contacted and steps are taken to balance. The effect is that Energinet.dk doesn't use a lot of secondary reserve, FRR, but can use the slower reserves instead (and therefore save money by using slower reserves in the balancing process).

4.2.2 SCHEDULING RULES IN ORDER TO FACILITATE LOAD FOLLOWING

4.2.2.1 OVERVIEW AND CLASSIFICATION

Scheduling rules stand for technical rules or financial incentives for scheduling to avoid high power steps in the schedules, at BRP/or generator level (principle 2) They could be taken in two ways, dependent on their point in time of application, i.e. before schedule nomination by the BRPs or after:

- **Ex-ante rules**: Rules that would impose some limits for scheduling which have already to be followed by generators/BRPs before schedule nomination:
    - Limits for schedule steps. The aim of these rules would be to avoid too large steps in the schedules of producers. Power output control would be advisable, in order to monitor the steps that are performed in real time.
    - Energy neutral adaptation of schedules, delivering power schedules that keep the hourly energy value, i.e. ramped schedules or 4-quarter schedules.

   - Schedule shifting of certain units applied before schedule nomination by BRPs themselves, in order to avoid the adding-up of large steps at the same time (change of hour). For the particular case of pumping storage plants with big capacity, a delay could be defined for the switching of their individual units.

- **Ex-post rules:** Rules that stimulate BRPs to physically realise big power schedule steps as network-compatible as possible <u>after schedule nomination</u>:

   - Ramp-based billing: The settlement of BRPs/generators is done against a ramp around schedule steps to incentivise the BRP/generator to physically realise a power output change as a ramp.

   - Schedule adaptions with regard to power and time values: In order to apply limits to scheduled power steps, schedules are adapted accordingly and settlement occurs against the adapted schedules. As every period will be priced differently, such changes in the schedules are in fact purchases and sales of energy which may involve financial compensation of BRPs/generators, even in the case that the schedule adaptions are energy neutral.

4.2.2.2 ENERGY-NEUTRAL ADAPTATION OF SCHEDULES

Delivering power programs that keep the hourly energy scheduled smoothing the associated steps can be done, both for generation units and/or for generation portfolios, in two ways. The first way is to calculate power ramps and the second one is to divide each hourly schedule into several blocks, each of them covering a shorter timeframe. Both methods are described – for the case of 1/2 hour ramps and 4-quarter steps respectively – in the previous report *"Deterministic frequency deviations – root causes and proposals for potential solutions"*" (/1/).

Both methods have a positive effect on frequency quality. The ½ hour ramp method offers advantages, as it fully eliminates the discrete output changes leading to frequency variations. On the other hand, it requires a near to real time monitoring and control of the generation output following the power ramp, whereas the 1-4 hour step method would only need ¼ hour metering and a longer timeframe monitoring and control of power output. **Fig. 5** shows an example of a ramped power schedule, and **Fig. 6** shows an example of ¼ hour step method.

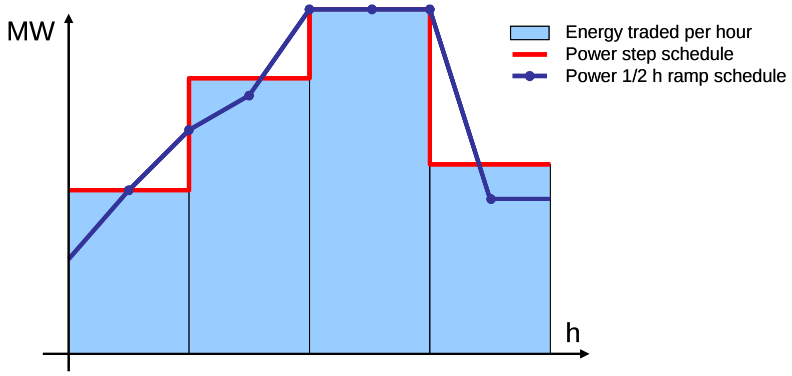

Fig. 5: Hourly step vs. half-hour ramp schedules

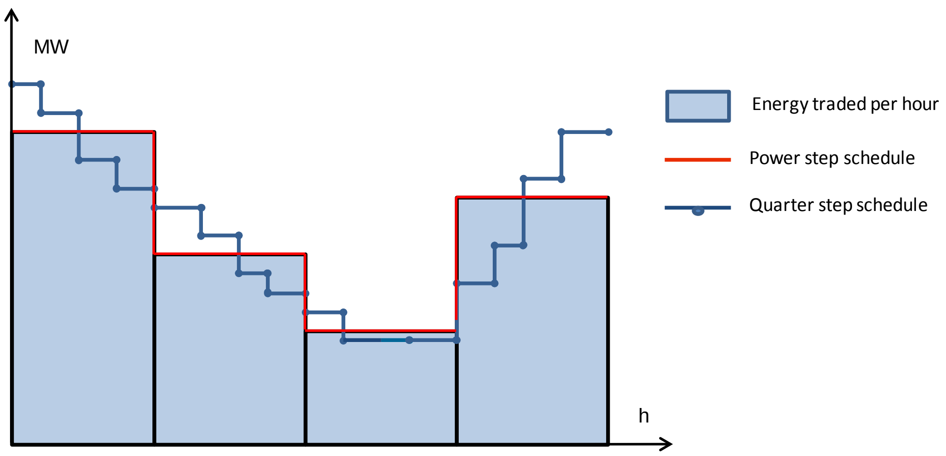

Fig. 6: Principle of hourly step vs. quarter hour steps

For half-hour ramps and for quarter steps, the calculation algorithms are quite similar. The adapted schedules are defined by a set of intermediate points, so two points define a power ramp and one point defines a step. Their values are calculated using the least-squares method, with the restriction of keeping the energy values for each hour. In the case of ramps, the objective function is the sum of squares of the distances of the intermediate points to the original hourly schedule. In the case of intermediate steps, the objective function is the sum of squares of the distance between all intermediate points. In **Fig. 7**, examples of the distances to be minimised are presented as red arrows for two hourly blocks:

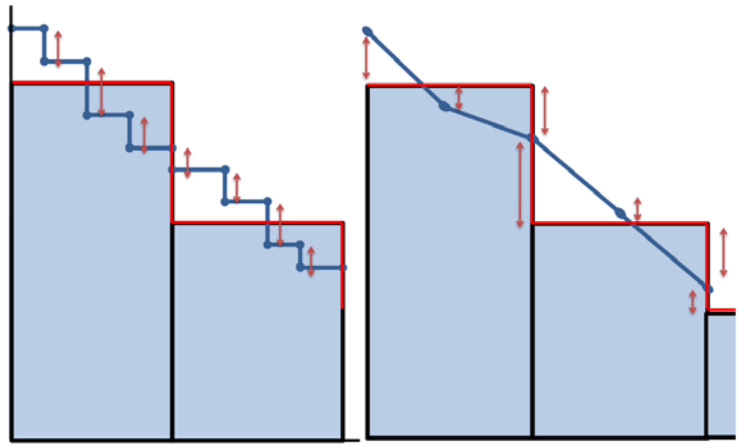

Fig. 7: Minimised variables for energy-neutral adaptation of schedules

Depending on the characteristics and the regulatory framework of each country, the applicability of these measures could be more or less complicated. For this reason, moving to this kind of schedules could be considered more as a mid-term or long-term term measure for several control areas.

4.2.2.3 Ramp Based Billing

In some countries where billing of imbalances is based on the comparison of metered energy and (discrete) schedules, such a measure has already been done to some extent by paying suppliers the inter-TSO ramping period they need to follow on behalf of the TSO.

By implementing the ramping period into the billing process the BRP are incentivised to follow the same ramps as they are imposed for TSOs. Consequently the balancing energy deviations are minimised and BRP and TSOs have an advantage for that in parallel with a decreasing impact on deterministic frequency deviations.

The main idea behind this measure is to avoid an inadequate cost recovering for the inadvertent exchanges compensation process.

The experience of this measure, already implemented in Switzerland for two years, gives promising results. Due to this measure it can be proved that the control quality has improved

The TSO of Romania is on the way of implementing at the level of market soft design a mechanism for adjusting the unit step scheduling especially for thermal power plants. The aim of this effort is to assure the units ramp rate capability and therefore control block real load following behaviour. This mechanism will be applied on a D-1 process basis in the sense that the schedule is corrected with a ramp so that the difference of energy will be taken as a dispatch order within the settlement process.

The prerequisites for the implementation of this measure are only related to the accounting process, no other interventions are required. The implementation of an incentive-based balance energy billing does not influence electricity prices as it does not influence wholesale markets. The adjustment sets proper incentives for balance responsible parties, in order to minimise their imbalance energy; if they do not ramp they pay balance energy. The opposite happens without an incentive based billing as balance responsible parties pay balance energy if they ramp their schedules.

However, since with this method the load following character could be adapted only for ten out of sixty minutes of on hour, the resulting related improvement is only restricted to this short period.

The application of such a measure depends on the method of calculation of the imbalances which is different between the TSOs. It is not applicable for some TSOs such as France where imbalances are directly calculated between metered generation and load (without reference to schedules).

4.2.3 Activation of balancing products

These rules give the permission and tool for TSOs to complement nominated schedules by activation of respective balancing products (principle 3). These measures are taken by the TSO when foreseeing big schedule steps that could lead to big frequency deviations. Producers are involved in proposing to the TSOs corresponding control products or adequate products on a balancing mechanism.

In this solution TSOs are in charge of the balancing in a short timeframe period in place of BRPs, assuming they have a better visibility on very short term imbalances and can act on a more efficient manner than dispersed individual BRPs.

The development and use of such products needs as pre-requisite that TSOs have the permission and appropriate tools to adjust schedules which are already nominated by producers, which is not the case of all the TSOs in Europe.

For TSOs in which a balancing mechanism exists, relatively small improvements are needed to get efficient tools to reduce market induced imbalances and consequently deterministic frequency deviations.

4.2.3.1. Schedule shifting

Schedule shifting could be used in the balancing market, being a product which can be activated by TSOs. The producers that could offer this product would be the ones that can deliver a big power output in a short time period (hydro units or pump-storage units). Power monitoring would also be advisable, in order to control that the delivery of power is made at the committed time. This method is described more in detail in the previous report *"Deterministic frequency deviations – root causes and proposals for potential solutions"*" (/1/).

This measure is already implemented in some TSOs (France, Nordic countries…). For example, RTE currently uses this kind of measure to smoothen the power output variation of big hydro units at the changes of hour as shown on the following example (2012, September 20th at 0:00).

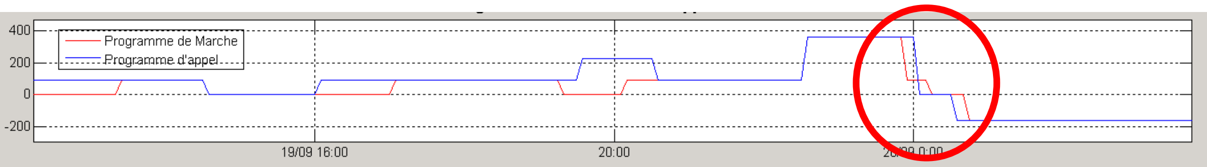

Fig 8: Example of shedule shifting : The producer schedule for a pump storage power plant (in blue colour) is modified by the TSO in order to smoothen the power output variation around 0:00 by applying a 10 minute shift before and after the change of hour (in red colour expected schedule after application of TSO balancing orders).

Additional examples of proactive schedule shifting as a recommendation for the Nordic system can be found in /3/.

4.2.3.2 RAMPED OR ADAPTED SCHEDULES

As described in section 4.2.2.1, energy generation schedules for generation units and/or generation unit portfolio can be converted using power ramps or energy schedules with a shorter timeframe than the current “hourly step” schedules, compatible with the current trading and operation practices When using ramped or stepped schedules as a balancing product, generators would submit to the TSO the power schedules upon TSO request after gate closure time, so the adapted schedule would become the basis for the settlement of imbalances.

4.2.3.3 SHORT TIME DURATION PRODUCTS

Proactive activation of reserves to compensate market induced imbalances at the change of the hour needs TSOs having appropriate balancing products at their disposal.

As deterministic frequency deviations are observed within a time window of about ten minutes centred on the change of the hour, balancing products of 5-10 minutes duration time are particularly well adapted for their mitigation.

Conventional generating units cannot generally start and stop so quickly. They need to operate during a certain time under stabilised conditions between two variations of output.

Small combustion engine based power plants have this capability but the capacity connected to the electric systems (DSO or TSO) is maybe too low to be at the scale of the control power needs.

A more attractive way to develop such short duration balancing products is to investigate demand side products (i.e. industrial process curtailment…).The difficulties to tackle with that kind of product are the need of aggregators to gather dispersed offers and the price of the product that should not be significantly higher than conventional balancing products. An additional difficulty has to be faced with products based on domestic process due to domestic meters that generally lack of enough time resolution to monitor the response to such a short solicitation.

4.2.4 MEASURES FROM TSO SIDE

The next solutions proposed affect only the TSO activities (principle 3) and have no direct consequences on market parties. The measures are the following:

1. **Extension of the ramping period of cross-border schedules**. Taking into account that the amplitude of frequency deviations correlates with the amplitude of changes of exchange schedules and that the standard CE LFC ramp of 10 min was defined before market opening and corresponding high power exchange volumes, an increase of ramping period might improve the situation. Maintaining the hourly market frame, a 15 or 30 minute ramp of interchange schedules will result in a better frequency control and more efficient use of restoration reserve. Starting from the fact that exchange program steps are supported by generators, this solution is closer to the real unit schedule change capability. In this manner the generation and exchange ramps can harmonise, with benefit for reserve activation. This approach can be used in the ¼ h market frame. Harmonisation with market time period (time frame and ramping time) is needed.

2. **Use of specific control regimes during ramping periods.** Exclusively during ramping periods TSOs can use different settings for e.g. DC-links than outside the ramping period. TSOs can also take some pro-active measures such as using replacement reserves to anticipate on expected imbalances or using pure frequency control mode on its LFC (emergency control mode) if the frequency is out of a given range. A prerequisite for the well-functioning of the DC-link solution is that all TSOs need to define the settings as described below:

   Make sure the DC-link-controller takes into account the frequency deviations of both not-synchronized zones: depending on ramp faster or slower depending on the sign of the frequency deviations on either side and the ramping direction (only when the frequency deviation opposites each other)

3. **Introduction of ramp restrictions on cross-border exchanges of energy.** Restrictions could be introduced lo limit exchange schedule variations from one step to another, in order to enable a better load following and mitigate the frequency variations. However this measure should only be a kind of last order measure. Further on such restrictions are already in use on the interface between synchronous regions due to other technical limitations.

4.2.5 Continuation of Measures and Scheduling Rules on the Long Run

In the long term the intervention of the TSOs in the scheduling process should be kept to a minimum, as effective rules should incentivise BRPs to balance their position and improve load following. Nevertheless, visibility of the power output and the ability of TSOs to supervise its performance by generators and BRPs will be necessary, in order to minimize deterministic frequency deviations in the future

Balancing products for the TSOs and ex-post rules in the long term would be set up depending on the incoming schedules, so the TSO would react when foreseeing critical schedules or correlations. The resulting ex-post schedule change should be energy-neutral for the generators/BRPs, and a compensation mechanism should be defined to avoid side effects on the participants or the settlement of imbalances. If the ex-post schedule involves a change of the energy position, the TSO will assume an energy position himself (the BRP cannot balance the position himself if the markets are closed) which has to be dissolved somehow (e.g. via energy booking into the control energy position). The schedule change could then be interpreted as a preventive call of control energy.

It should be clear that, when the practical realisation of scheduling rules by the TSOs leads to an “energy shift”, the corresponding costs or revenues should be part of the methodology of imbalance pricing which according to the current draft of the Framework Guidelines will be harmonised in the future.

4.3 Recommendations

1) Follow closely the drafting process for the several network codes, in order to ensure:

For NC Balancing: a) that BRPs are in the position to balance their portfolio (or help the system) as closely as possible to real time by means of well-functioning financial incentives and a suitable settlement time interval, and b) that TSOs do have enough flexibility in choosing balancing energy (ramping) products. Also ensure that adequate provisions for the pricing of balancing energy are in place.

For Network Code for Load Frequency and Reserves apart from the recommendations mentioned in paragraph 4.1.3., that a definition and .evaluation criteria for DfD is incorporated.

2) Implementation of the proposed measures on national TSO level needs to be done in accordance with national market design.

3) Make sure that energy costs TSOs have to pay to BRPs during the execution of measures mentioned in the previous point (e.g. ramp based billing) can be recuperated in accordance with national legislation.

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5 MONITORING AND ALARMING

As a supplementary short-term measure it is recommended to implement, at the scale of an overall synchronous zone, a monitoring and alarming process which is able to forecast critical situations, in which very large deterministic frequency deviations have a high probability to occur. This process should also be designed to send a warning to the TSOs concerned (or directly to producers concerned) so that they take measures to smoothen the generation changes and to mitigate the frequency deviations.

The implementation of such a monitoring and alarming process is expected to increase significantly the efficiency of some of the measures described in chapter 4.

Based on the presence of correlations between large frequency deviations, overall load curve and steps in the overall generation program (for the synchronous zone), this process may consist in:

- Collecting the generation programs and other relevant data before real time.
- Calculating alarm thresholds.
- Sending of warnings to TSOs or producers concerned so that they take measures.

A coordination entity, at the scale of an overall synchronous zone, may be in charge of running this process.

The parameters to be monitored may include:

- Overall load curve for the synchronous zone.
- Overall generation program for the synchronous zone.
- More particularly overall hydro generation program.
- Cross-border exchanges.

They may be used to calculate indicators that could be compared to alarm thresholds which trigger the sending of a warning to TSOs or producers concerned.

Examples of alarm thresholds could be a combination of thresholds for the changes in the overall generation schedule or in the overall hydro units' schedule, modulated according to the level of the overall load curve and the period of the day (ramping periods or not).

The proposed measures on the forecast level should be completed with a corresponding transparent real-time monitoring of LFC values such as ACE as well as with adequate standard reports.

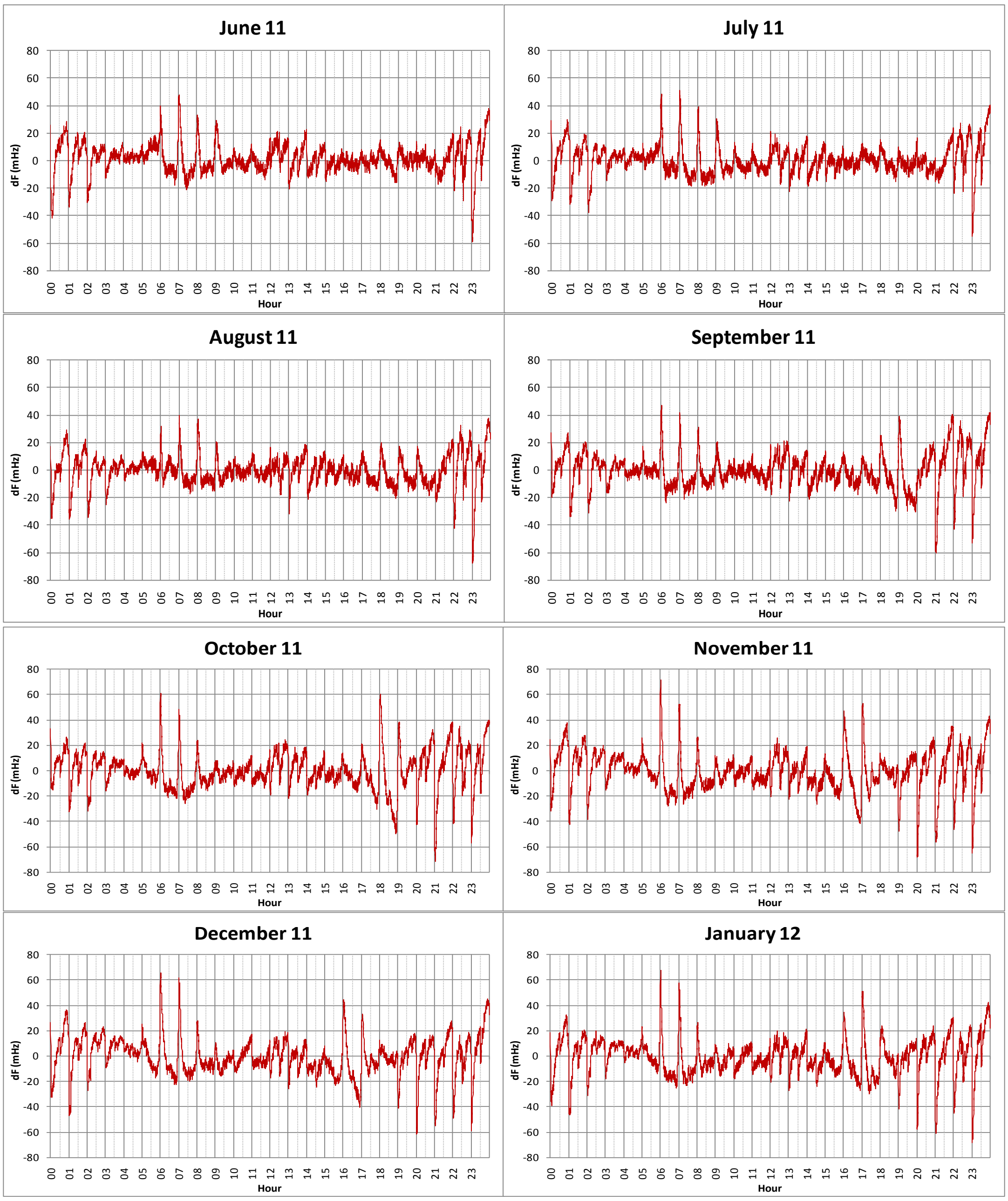
The adequate platform for on-line LFC monitoring might be the ENTSO-E awareness system and the standard reports might be included in the already existing ENTSO-E quarterly reports.

5.1 STUDY ON CORRELATION BETWEEN DFDS AND SCHEDULE STEPS

In order to do some research on the possibility of forecasting DFDs, the correlation between them and energy day ahead schedules was studied.

In the first stage of the study, the frequency deviations were compared with the day ahead exchange control programs between countries. In the second stage of the study, internal generation schedules from several countries were collected and compared with the frequency deviations.

The frequency deviation data for every 10 seconds in CE were collected for the period between June 2011 and May 2012. In **Fig. 9**, the monthly average values of frequency deviations are presented, showing the behaviour of DFDs and their evolution during the year. It is remarkable that some DFDs can be foreseen not only in the change of the hour, but also in the half hours (this fact can be clearly seen, e.g., between 21 and 24 hours during almost all of the months). This fact should be considered for the definition of DFDs, mainly in the future, when the time frame of energy schedules may be shorter in more countries.


June 11
July 11
August 11
September 11
October 11
November 11
December 11
January 12
dF (mHz)
Hour
80
60
40
20
0
-20
-40
-60
-80
00 01 02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23

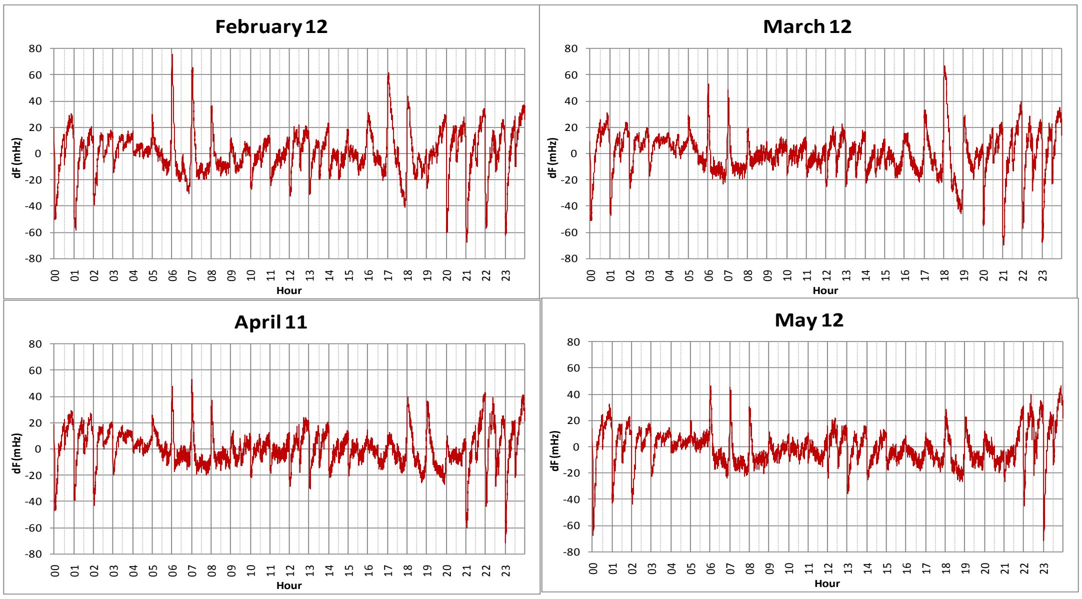


Fig. 9: Average monthly frequency profiles from June 11 to May 12

5.1.1 COMPARISON OF DFDS VS. DAY AHEAD CONTROL PROGRAMS

In the first stage of the study, the day ahead exchange control programs were collected for the rolling year between June 11 and May 2012. Although the DFDs are not directly related to exchange programs, but to the difference between generation and load, the exchange programs steps give somehow a measure of the difference between generation and load that is taking place in each change of hour. Besides, the information about exchange programs is easily available in the VulcanuS system, unlike the internal generation schedules which require much bigger effort to collect for the CE region.

The frequency deviations were filtered for the time window of +-7.5 minutes around the shift of each hour. For each collection of frequency deviations in that time window, the maximum value was taken as the measure of the DFD in that hour.

Regarding the day ahead exchange control programs, the differences between the program of each hour and the next were calculated for each control block. The absolute values of the results were summed and taken as the variable for the study. In the **Fig. 10**, the cloud of measured frequency deviations is presented versus the sum of differences between exchange programs. As it can be seen, there's not a clear correlation between those variables if they are directly represented. The correlation coefficient (R^2) takes a value of 0.12, which indicates a poor correlation level.

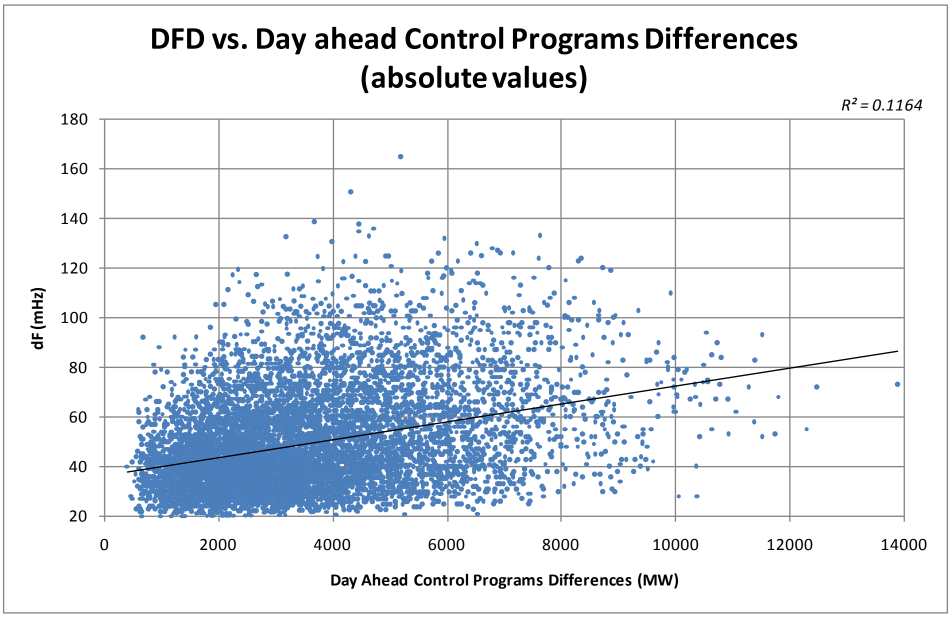


Fig. 10: Cloud of DFD vs. Day ahead control programs differences

The correlation results can be significantly improved if the data are grouped into power step ranges and the average of the frequency deviation is calculated for each set of data. **Fig. 11** presents the result when data are grouped by sets of 100 MW. As it can be seen, the correlation coefficient R^2 takes a value of 0.75. The result can be improved even more if the highest values of power steps are filtered, as they present more variability in terms of associated frequency deviations. The result is presented in **Fig. 12**, with a correlation coefficient of 0.937.

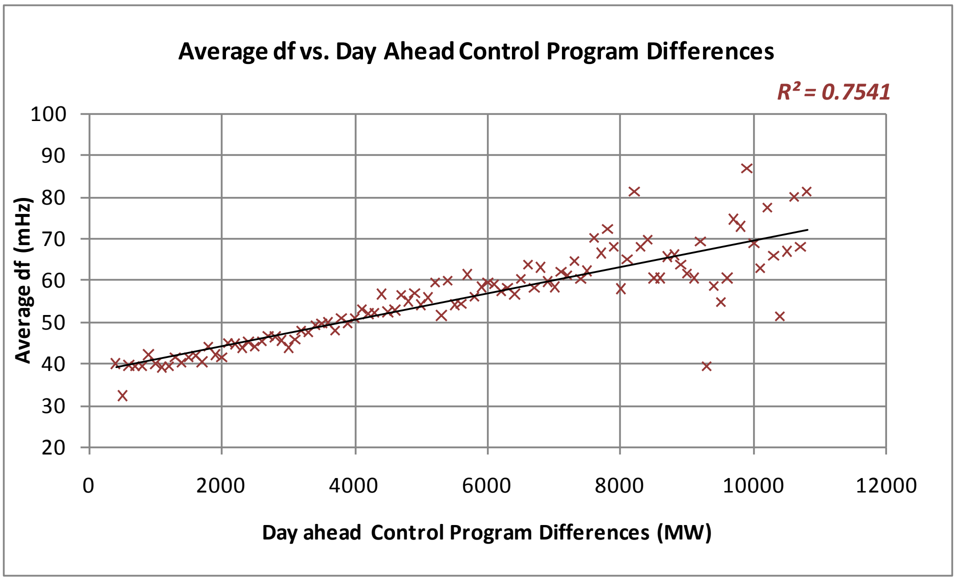


Fig. 11: Average DFD vs. Day ahead control programs differences, grouped by steps of 100 MW

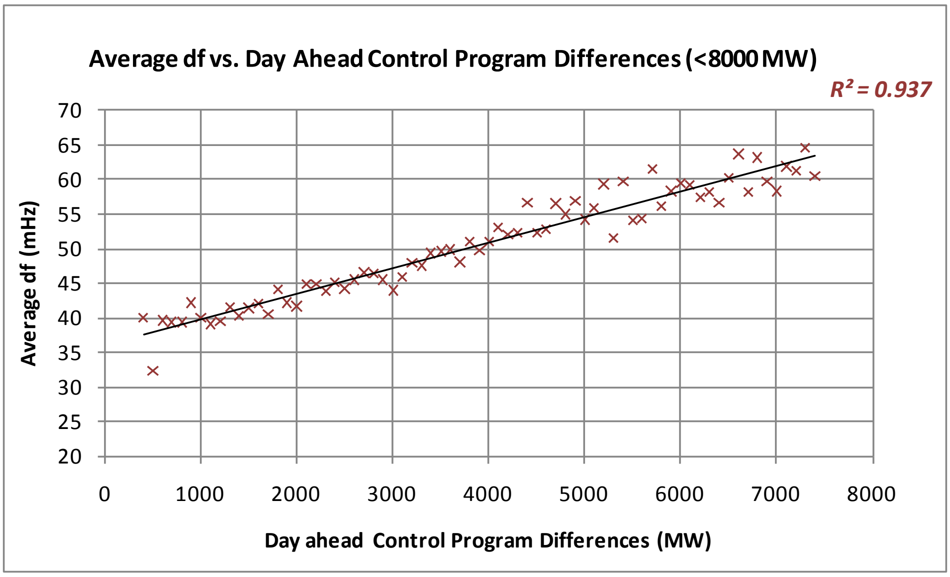


Fig. 12: Average DFD vs. Day ahead control programs differences, grouped by steps of 100 MW and filtered for steps <8000 MW

These results show that there is some kind of correlation between the exchange schedules steps and the deterministic frequency deviations taking place. This correlation is however not enough to deduce that a forecast of frequency deviations can be made from the inter-hour steps. **Fig. 13** shows the statistical data on grouped DFDs, and the variability of data makes it not suitable to deduce a forecast of DFDs from the day ahead control programs steps. Nevertheless, these results give an incentive to forward research. In some way, the inter-hour schedule steps give a measure of the steps in the internal generation schedules.

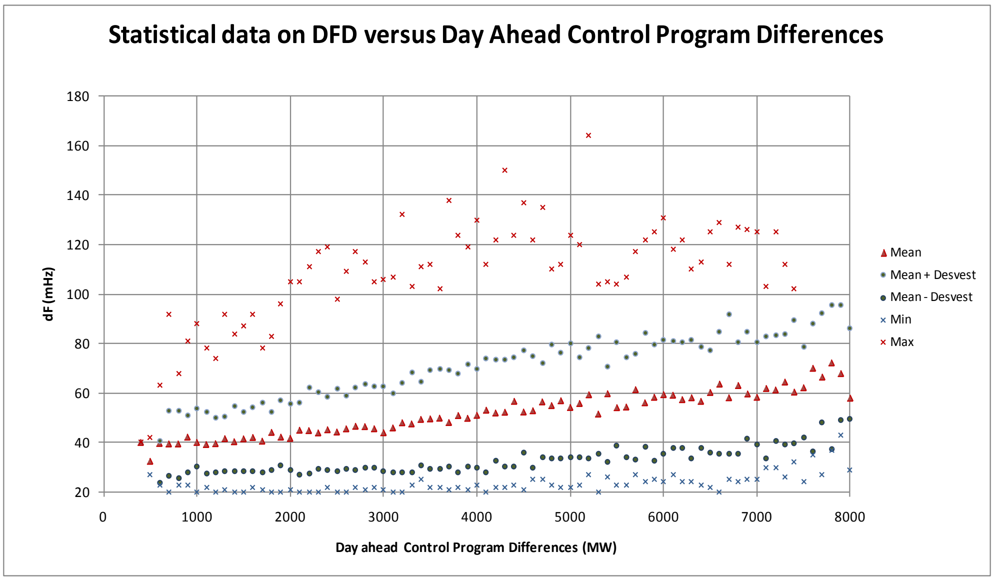


Fig. 13: Statistical data of DFD vs. Day ahead control programs

5.1.2 Comparison of DFDs vs. Day Ahead Generation Schedules

In order to develop a further research about the possibility of forecasting the risk of large DFDs, the day-ahead internal schedules of several TSOs were collected for the months of January 2012 and May 2012.

The data received at the moment are only a part of the total power of the synchronous area of CE, so the results obtained are limited. Nevertheless, the preliminary results are presented. The following data were available for the study:

- Swissgrid: January and May 2012.
- REE: January 2012 and May 2012.
- REN: January 2012 and May 2012.
- RTE: January 2012 and May 2012.
- TEL: January 2012 and May 2012.
- Tennet NL: January 2012 and May 2012.
- Germany: January 2012 and May 2012 (no pump storage consumption data available).
- Austria: January 2012 and May 2012 (no pump storage consumption data available).

The RES forecasted generation was not taken into account for the study, as it has no influence on the DFDs. The differences between the generation schedules of each hour and the next were calculated for each area, calculating the sum of the steps. In **Figs. 14** and **15**, the cloud of measured frequency deviations is presented versus the sum of differences between schedules. As it can be seen, the dispersion of data makes it difficult to see a clear correlation.

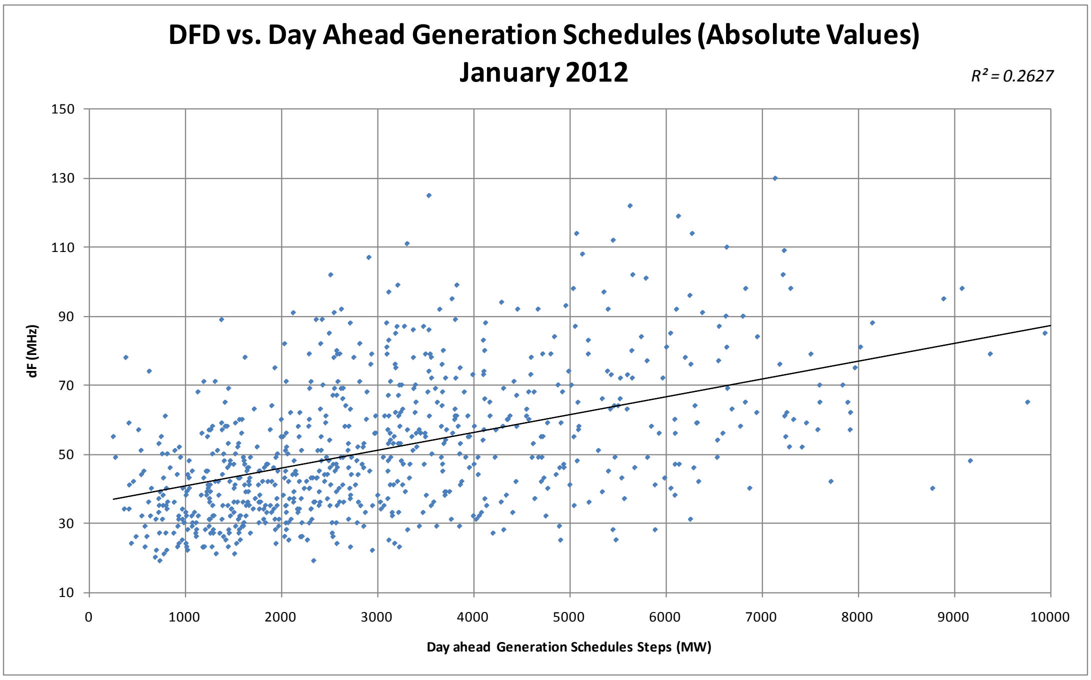


Fig. 15: Cloud of DFD vs. Day ahead generation schedules steps. January 2012

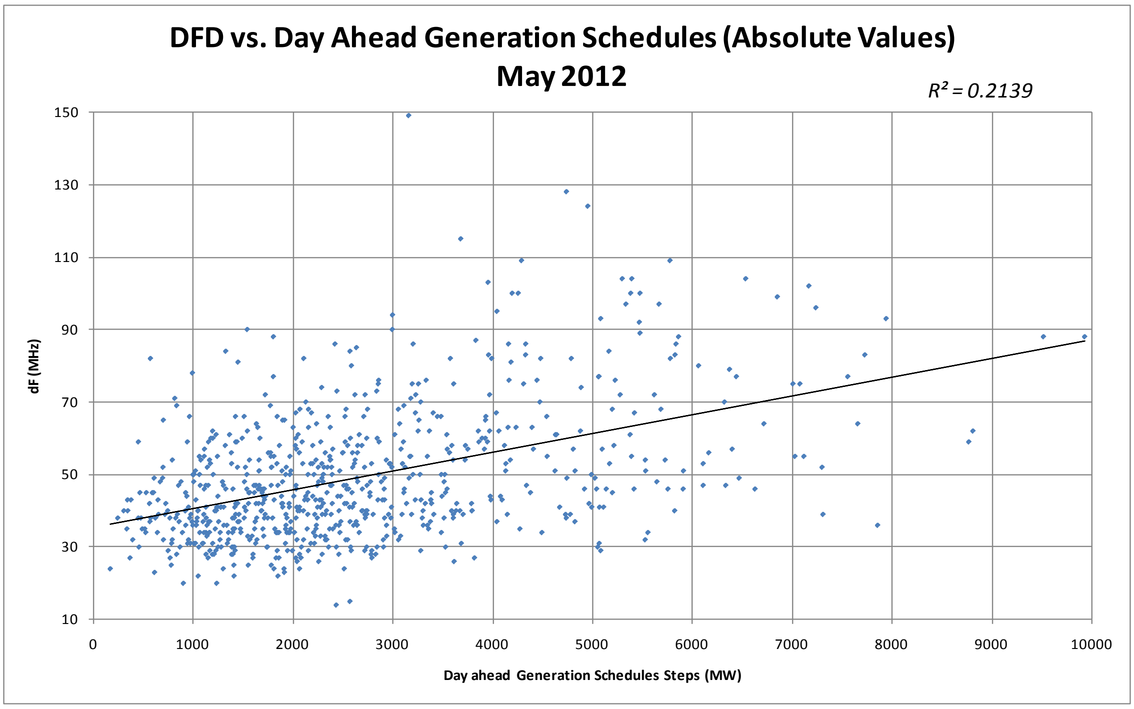


Fig. 15: Cloud of DFD vs. Day ahead generation schedule steps. May 2012

Figs. 16 and **17** show the results obtained for the months of January and May when the frequency deviations are averaged over schedule steps ranges of 500 MW. As it can be seen, the correlation coefficients are significantly improved.

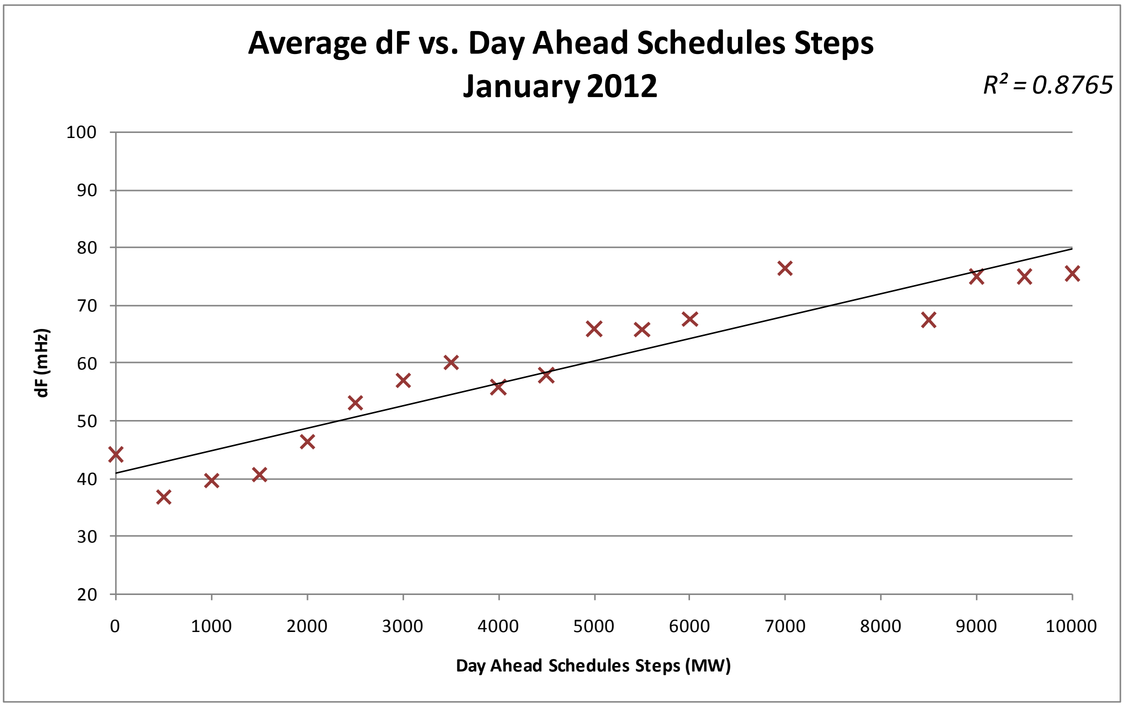


Fig. 17: Average DFD vs. day ahead gen. schedules differences, grouped by steps of 500 MW January 2012

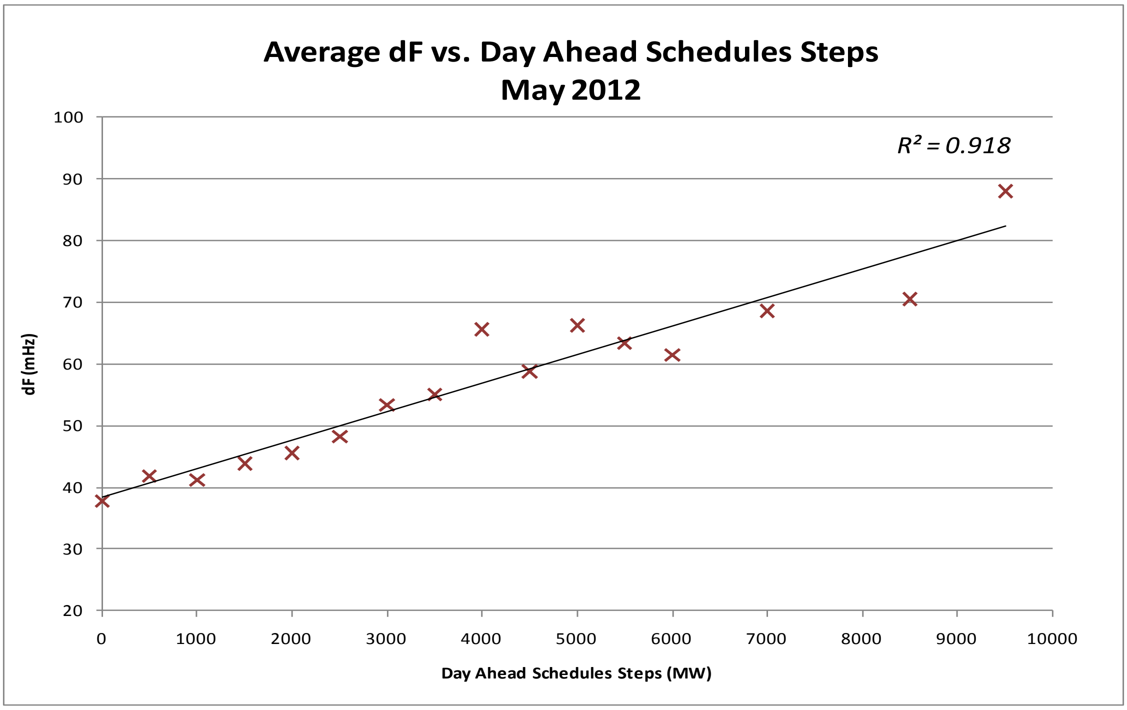


Fig. 17: Average DFD vs. day ahead gen. schedules differences, grouped by steps of 500 MW May 2012

In order to assess the possibility of using day-ahead generation schedules for alarming and forecasting needs, the frequency deviations for the months of study have been filtered, taking as DFDs the deviations which meet the criteria described in **Annex 1** (|dF| >50 mHz during the ¼ hour around the change of the hour). The day-ahead scheduled generation steps have been grouped, obtaining the results in **Table 1** and **2**. The number of steps in each range is presented, together with the number of associated DFDs. As it can be seen, the probability of occurrence of DFDs is clearly related to the magnitude of the steps. However, it can be expected that with a more complete set of data, the quality of the results will improve substantially.

Table 1: **Schedule Step Range and DFDs during January 2012**

Schedule Step Range (MW)	*Number of Ocurrences in the Month*	*Number of DFDs*	*%*
0-1000	74	10	14%
1000-2000	227	55	24%
2000-3000	208	73	35%
3000-4000	102	51	50%
4000-5000	53	35	66%
5000-6000	48	32	67%
6000-7000	14	10	71%
>7000	17	15	88%

Table 2: Schedule Step Range and DFDs during May 2012

Schedule Step Range (MW)	*Number of Ocurrences in the Month*	*Number of DFDs*	*%*
0-1000	64	11	17%
1000-2000	181	31	17%
2000-3000	163	64	39%
3000-4000	133	86	65%
4000-5000	71	42	59%
5000-6000	51	35	69%
6000-7000	38	29	76%
>7000	41	38	93%

.

In order to improve the results and to allow accurate forecasting of DFDs, the following actions are suggested:

- Expand the collection of day ahead schedules, including the schedules of as many TSOs as possible, as the current results are very promising.
- Include the disaggregation of the schedules of fast units –mainly large hydro and pump storage units (consumption and generation). The schedules steps of these units in the hourly shifts are the main causes of DFDs, so the disaggregation of these schedules would help forecasting large DFDs.

Besides, the following conclusions can be derived from the analysis performed:

- The total accuracy of statistical global data has increased proportionally with the number of input data;
- The conclusions are more consistent being based on data analysis provided by control blocks with different size and generation characteristics.

6 REFERENCES

/1/ Deterministic frequency deviations – root causes and proposals for potential solutions, A joint EURELECTRIC – ENTSO-E response paper, December 2011, https://www.entsoe.eu/fileadmin/user_upload/_library/publications/entsoe/120222_Deterministic_Frequency_Deviations_joint_ENTSOE_Eurelectric_Report__Final_.pdf

/2/ Operational reserve ad hoc team report, final version, 23.05.2012, https://www.entsoe.eu/resources/network-codes/load-frequency-control-reserves/

/3/ Intra-Hour Imbalances and Ramping on Interconnectors, Report on behalf of Statnett, January 2012, E-Bridge

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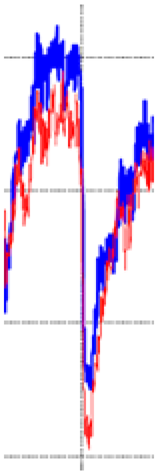
Annex 1: Proposed criteria for DFD evaluation

Monitoring and reporting of deterministic frequency deviation shall be based on the following criteria:

- Evaluation of frequency recording around pre-defined time window = change of the hour (-7.5 min - +7.5 min) with ¦dfmax¦ > 50 mHz -> ouput = delta f; fmax; duration, see following Fig. This deviation is considered to be based on the standard frequency range for CE =+/- 50 mHz.



- Quality of measurement = same requirement as for load frequency control - 1.0-1.5 mHz and time resolution between two measurements at least 4 seconds
- One measurement point + backup is sufficient for one synchronous area

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