Resilience of the DSO network near 50.2Hz

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ABSTRACT

In an electrical system where decentralized and embedded productions are becoming more and more important, it is essential to ensure good understanding of their behaviour at their operating limits. One the most important operating limit is when the system frequency approaches 50.2 Hz. At this frequency existing PV inverters a disconnection rules is activated. In such situation, we will demonstrate that the variance of the frequency measurement done at every PV inverters plays a key role. It will be showed that this variance is actually a good thing from the system point of view. It is allowing a gradual disconnection, leading to a controlled variation of the frequency.

INTRODUCTION

System frequency starts deviating whenever an imbalance between generation and demand occurs. The speed at which frequency changes (also called Rate of Change of Frequency (RoCoF)) is inversely proportional to the total inertia of rotating masses. As this inertia originates from synchronous generators, system operators observe its degradation induced by a shift of generation from classical synchronous machines to power electronics-based (non-synchronous) generation, mostly connected to Distribution System Operator (DSO) grids. This degradation is even more important in low load conditions because the proportion of non-synchronous generation is more important.

It is thus essential to ensure good understanding of the behaviour of both the system and those non- synchronous generators when the latter operate near their limits. Precisely one of the most important operating limits is when the system frequency, following the ENTSO-E reference incident of losing 3 GW load, in low load conditions, approaches 50.2 Hz. At this frequency, even when taking into account the retrofit policy effective in Germany, a lot of Photo-Voltaic (PV) inverters would be disconnected from the grid, owing to the built-in protections.

Considering that it involves hundreds of thousand PV installations, simulating the system frequency response with a single large, equivalent PV unit is not appropriate. Stochastic approaches need to be further explored, taking into account the way frequency is sensed by the various PV inverters at different time instants of the frequency evolution.

In this paper, we will explain that, in this situation, the variance of the frequency measurements taken locally by the various PV inverters plays a key role. It will be structured as follows.

In the Section I, we will define the requirements and targeted performance for the frequency by taking into account the requirements imposed by ENTSO-E.
Section II will give a summary of the way of considering the frequency behavior. A model to assess the system facing a sudden event will be described in Section III.
The specific behavior of a PV inverter in response to frequency variations will be analyzed in Section IV, while Section V will state more precisely the problem for the normative 3000 MW incident as requested by ENTSO-E. The 2 scenarios are explained at Section VI.
The results of the simulations will be given in Section VII, while Section VIII will present the main conclusions and suggest possible further works.

SECTION I: REQUIREMENTS FOR PRIMARY FREQUENCY REGULATION

Table 1 in the appendix defines the main terms used to characterize the frequency and primary reserve.
It also gives the performance target values. These target values come from [1].

SECTION II: MATHEMATICAL FORMULATION OF THE FREQUENCY BEHAVIOUR

The well-known swing equation for one j generator is expressed as:

$$J_j.\frac{d\omega}{dt} = \frac{P_{g,j}}{\omega_j} - \frac{P_{e,j}}{\omega_j} \quad (1)$$

Where, for each j unit:

J_j	is the moment of inertia in $kg\ m^2$
$P_{g,j}$	is the power generated (MW)
$P_{e,j}$	is the electrical power (MW)
ω_j	is the rotating speed

In order to ensure system stability, we need to solve this differential equation to assess if $\frac{df_j}{dt}$ return to zero after being subject to a disturbance corresponding to the difference between $P_{g,j}$ and $P_{e,j}$.

As $\omega = 2.\pi.f$, we have:

$$J_j.2.\pi.\frac{df_j}{dt} = \frac{1}{2.\pi.f_j}\left(P_{g,j} - P_{e,j}\right) \quad (2)$$

For the rotating generator, we can introduce a factor H, the inertia constant that characterize the generating unit:

$$H_j = \frac{\frac{1}{2}.\omega_0^2.J_j}{S_{n,j}} = \frac{\frac{1}{2}.J_j.(2.\pi.f_0)^2}{S_{n,j}} \quad (3)$$

Where f_0 is the nominal rotating speed, $S_{n,j}$ is the nominal apparent power of unit j (in MVA).

We do not consider the variation of the frequency in different sub zone within the area. With other words: all the SACE is running at iso-frequency. As consequence of this, the rotating speed of each j unit may is the same.

Assumption 1: All generators are rotating at the same speed.

For the whole system with N generating units, and taking (3) into account, (2) becomes:

$$\frac{df}{dt} = \frac{f_0^2}{2.\left(\sum_{j=1}^{N} H_j.S_{n,j}\right).f(t)} . \left(\sum_{j=1}^{N} P_{g,j}(t) - \sum_{j=1}^{N} P_{e,j}(t)\right) \quad (4)$$

For the purpose of this paper, we will not cover angle stability, voltage issue or congestion.

Assumption 2: The network will be considered as a copper plate.

Giving this last assumption, we can consider that $\sum_{j=1}^{N} P_{e,j}(t)$ is corresponding to the total load of the network. For the reader convenience, we will use and P_L instead of P_e in the rest of the paper.

Assumption 3: P_L included also all the transmission /distribution losses and the power generated by non-rotating generators (embedded local renewable generation).

$$\frac{df}{dt} = \frac{f_0^2}{2.\left(\sum_{j=1}^{N} H_j.S_{n,j}\right).f(t)} . \left(\sum_{j=1}^{N} P_{g,j}(t) - \sum_{k=1}^{B} P_{L,k}(t)\right)$$

(5) where B is the total of load units.

SECTION III: MODELLING

General Model

To solve this equation (5), we will use an Euler approximation of the differential equation to simulate the response of the system (also used in [2],and [3])

Euler's method is one of the simplest methods to program a solution to differential equations.

Let's take a general function **z**: $\mathbb{R} \rightarrow \mathbb{R}$ and its derivative

$y: \mathbb{R} \rightarrow \mathbb{R}$

$$\frac{dz(t)}{dt} = y(t, y(t)), \quad y(t_0) = y_0$$

We can put z in a time space $[t_0,\ T_f]$, t_0 is corresponding to the initial time and T_f the final time.

Therefore, we can discretize z in M intervals with Δt as interval. Every value at each m interval (m = index of the interval) can be computed on the base of z and y at *m-1* interval.

$$z^{m+1} = z^m + \Delta t\ .y(t^m, z^m) \ \ \forall m = 1 \ldots M-1 \quad (6)$$

We use (6) in the equation (5) and it becomes (7):

$$f^{m+1} = f^m + \Delta t.\frac{f_0^2}{2.\left(\sum_{j=1}^{N} H_j\ .\ S_{n,j}\right).f^m} . \left(\sum_{j=1}^{N} P_{g,j}^m - \sum_{k=1}^{B} P_{L,k}^m\right) \quad (7)$$

The system is modelled with

- The N generating units are:
  1. generating unit at value $P_{GC\ in}$ MW, this unit is not frequency sensitive.
  2. one generator provisioning the primary reserve at P_{R1} in MW
- The B load units are:
  1. one load (P_L in MW), this load is not frequency sensitive
  2. the disturbance ΔP_L (in MW) is the initial event.
  3. Embedded generating unit (negative load) at value P_{GRS}, in MW, corresponding to power generated by PV inverters not subject to frequency variation (see section V)
  4. Embedded generating unit (negative load) at value P_{GS}, in MW, corresponding to power generated, before the event occurs, by PV inverters potentially subject to power output variation in function of frequency deviation.
  5. ΔP_{GS} is the power automatically release (not more produced) by PV inverters due to internal frequency disconnection rules.
  6. one load (P_R in MW), with automatic demand release, image of the load impacted by the change in frequency.

To make the link with (5),

$$\sum_{j=1}^{N} P_{g,j}(t) = P_{GC} + P_{R1}(t) \quad (8)$$

And,

$$\sum_{k=1}^{B} P_{L,k}(t) = P_L - \Delta P_L - P_{GRS} - P_{GS} + \Delta P_{GS}(t) - P_R(t) \quad (9)$$

The Euler relationship becomes:

$$f^{m+1} = f^m + \Delta t.\frac{f_0^2}{2.\left(\sum_{j=1}^{2} H_j\ .\ S_{n,j}\right).f^m} . \left(P_{GC} + P_{R1}^m - P_L + \Delta P_L^m + P_{GRS} + P_{GS} - \Delta P_{GS}^m + P_R^m\right) \quad (10)$$

We will now describe P_{R1}^m, P_R^m and $\sum_{j=1}^{2} H_j\ .\ S_{n,j}$ in detail. ΔP_{GS}^m will be described in section IV.

P_{R1}^m : The primary reserve regulation

The generator provisioning the primary reserve has a frequency sensitive governor that automatically detects the frequency deviation and updates its power generated in order to stay in the frequency quality target values.

The first step of the simulation of the primary reserve (R1) is to compute the target value of the primary reserve

(P_{tar}). The primary reserve capacity is limited to P_{PC} MW as the total primary reserve contracted by TSO.
In this paper we will introduce a "near to" real life proportional controller corresponding to the performance already described in first section:

- $|\Delta f| \in [0,20[\rightarrow P_{tar} = 0$
- $\Delta f \in [20,200] \rightarrow P_{tar} = -\frac{\Delta f}{0.2}.P_{PC}$
- $\Delta f \in [-200,-20] \rightarrow P_{tar} = \frac{\Delta f}{0.2}.P_{PC}$
- $\Delta f \in]200,+\infty] \rightarrow P_{tar} = -P_{PC}$
- $\Delta f \in [-\infty,-200[\rightarrow P_{tar} = P_{PC}$

Due to its internal inertia and control delay, the generator providing R1 needs time to rise up/decrease to this value P_{tar}. The second step of the R1 simulation takes that into account by reducing the error between P_{tar} and the actual output P_{R1}.
In the Laplace domain, we can write:

$$P_{R1}(s) = \frac{1+s.\tau_c}{1+s.\tau_r}.P_{tar}(s) \quad (11)$$

With τ_c the time delay coming from the control system and τ_r is the time constant of the primary regulation controller. We can rewrite (11) in its time domain:

$$\Delta P_{R1}(t) + \tau_r.\frac{d\Delta P_{R1}(t)}{dt} = \Delta P_{tar} + \tau_c.\frac{d\Delta P_{Tar}(t)}{dt} \quad (12)$$

We apply the same Euler method as described here above to this equation (12):

$$\Delta P_{R1}^{m+1} = \Delta P_{R1}^{m}.\left(1-\frac{\Delta t}{\tau_r}\right) + \Delta P_{tar}^{m}.\left(\frac{\Delta t-\tau_c}{\tau_r}\right) + \frac{\tau_c}{\tau_r}.\Delta P_{tar}^{m+1} \quad (13)$$

The requirements of the TSO regarding the response time of units providing R1 is to deliver the full capacity power within 0 to 30 seconds (see for example [4]).
Assumption 4: the full capacity is deliver before 15 seconds. Therefore, the typical time responses for the P_{R1} are:

- τ_r = 1.75 seconds
- τ_c = 0.1 second

P_R: Automatic Demand released

Many papers (e.g. [2] and [3]) using system simulation consider that a small part of the demand is directly influenced by the frequency. It is generally accepted that demand decreases or increases by 1% to 2% for a Δf of 1%.
We decide to take that effect into account.
This choice has consequences that we have to treat it as a generating unit helping the primary reserve.
Let P_R be this power released by the demand.

$$P_R = -D.(P_L - \Delta P_L^m).\frac{\Delta f}{f_0}, \quad (14)$$

Assumption 5: D=2.0 (corresponding to 2%)

Kinetic Energy stored in the system and system inertia

As kinetic energy, we will only consider the rotating generating unit. We will consider that the PV installation has no inertia. As consequence, P_{GRS} and P_{GS} will not be taken into account for the calculation of the system inertia.
Off course, P_{GC} is the image of these rotating units. We will consider that all these units are steam turbines and have an equivalent H of 4 MW.s/MVA.
It is important to note that we consider that the primary reserve capacity is well connected to the system even if these P_{R1} units do not give or take power to/from the system. So P_{PC} will be part of the kinetic energy also with H equal 4 seconds.
As consequence of this, the inertia of the system will not change during the simulation steps.
We had expressed P_{PC} and P_{GS} in MW therefore, to estimate S, we need to make an assumption on the power factor of these units.
Assumption 6: the equivalent units for P_{PC} & P_{GC} have a power factor equal to 0.75.
With assumption 5 and 6, relation (3) becomes:

$$\sum_{j=1}^{2} H_j . S_{n,j} = 4.\left(\frac{P_{GC}}{0.75} + \frac{P_{PC}}{0.75}\right) \quad (15)$$

SECTION IV: BEHAVIOR OF PV INVERTERS IN FUNCTION OF THE FREQUENCY

Previously (before 2011), Germany, France, Belgium and Slovakia had put a disconnection requirement for all PV inverters at 50.2 Hz.
In 2011, a study [5], done by the four German transmission system operators (TSO), the distribution network operators (DSO), the German Solar Industry Association (BSW-Solar), including representatives of various PV inverter manufacturers, and the VDE, concluded that the total cost for the retrofitting of the PV systems was estimated between 65 to 175 million euro, plus associated administrative costs for inverter manufacturers and distribution network operators.
Despite these high costs, the risk (see also chapter "problem statement") was considered as too important and a retrofit plan (in 3 years) of 315,000 PV plants, for a cumulated installed power of 10,500 MW, was putted into force in 2013 for whole Germany. The new rules set the disconnection frequency above 51.5 Hz. The other countries did not change their requirements.
The recommendation [7] set that, in case of frequency disturbance, the system shall disconnect after 6 cycles. For a system at 50 Hz, this is 0.120 s. We will use this value for our simulation.
Assumption 7: the disconnection of PV inverters is done within 0.120 s.

SECTION V: SIMULATION TOOL AND PROBLEM STATEMENT

Simulation tool

For each slice (Δt) of the simulation, after the event occurs, and until m≤M (M equal the time horizon of the simulation that we set at 60 seconds), we calculate

sequentially:

- f by using equation 10 and parameter H
- ΔP_{GS} : see description in the next section
- P_{R1} : the power developed by the primary controller considering the time parameters τ_r and τ_c. This power has to be less or equal to P_{PC}. (see eq. 13)
- P_R : the load released in function of the frequency with the parameter D. (see eq. 14)

Problem statement

The conclusion of the study [5] was a possible collapse of the German electricity system with the actual primary reserve capacity. In this paper, we will compare the frequency behavior for 2 scenarios. In the first scenario, we will assume that there is no variance in the frequency measurement. All the PV inverters stop at 50.2 Hz (also called the common disconnection mode).
For the second scenario, we will take a certain variation of the frequency measurements into account (called variance of measures).
As comparison variable, we will use the needed primary reserve volume needed to stabilize the system considering the PV inverters disconnection. This needed primary power reserve is a good indicator of the stability of a system subject to a disturbance because it gives also an idea of the cost to stabilize such system.

SECTION VI: BUILDING THE SCENARIOS

State of the system and initial event

We will simulate the Synchronous Area Continental Europe (SACE), of the former UCTE synchronous area. This is a large system corresponding to several countries (see appendix II).
At the start of the simulation, the system is balanced and:

- $\sum_{j=1}^{N} P_{g,j}^{m=0} = P_{GC}$
- $\sum_{k=1}^{B} P_{L,k}^{m=0} = P_L - \Delta P_L - P_{GRS} - P_{GS}$

In this paper, we will only asses the most critical scenario, at t=0 (or m=0), a loss of 3 000 MW of load (ΔP_L) during the off peak period (P_L = 156 244 MW)
Assumption 7: we consider that the German retrofit is done.
With this assumption, P_{GRS} will be estimate as equal to 10500 MW.
The part of the generation done by PV impacted by inverter settings at 50.2 Hz is P_{GS} = 8030 MW.

Scenario 1: Common disconnection mode

For the first scenario, within our formulation, ΔP_{GS} will be equal to P_{GS} = 8030 MW at the very moment when the frequency is reaching 50.2 Hz.

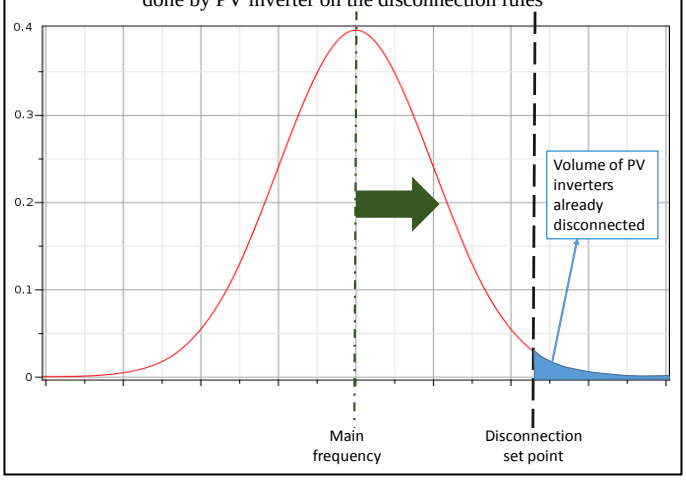
Scenario 2: Variance of measures

For Europe, the subjects of frequency measurements are treated in a CENELEC workgroup (TC8X). They published technical requirements [6]. This document establishes (at § 4.6.1 Power response to over-frequency) the resolution of the frequency measurement shall be +/- 10 mHz or less. But resolution (what is shown on the screen of the inverter) doesn't tell more about accuracy.
The lack of requirements about frequency accuracy has been considered as important from the CENELEC. That is why a new standardization group has been started in 2016.
We will than use some other international standards.
The source [7] requires, in the chapter for minimum test procedure, that the measurement error for frequency shall be less (<) 0.1 Hz. We will use this value for the PV inverter.
For the scenario 2, we will take the statement that the measurements of the frequency by PV inverters follows a normal distribution with the standard deviation equal to 0.0333 (0.1/3), equivalent as saying that 99.73% of the PV inverters fulfill the requirement of [7].
We have to be very clear about the interpretation of this.
When the main frequency is f=50.1667 Hz, the display of a specific inverter with +3 σ will show 50.20 Hz and that inverter will follow its implemented rules as the frequency is really 50.20 Hz.
What happen when the network frequency moves near to the stetted frequency point for disconnection?
Due to the variance of the measure, some PV inverters will already be disconnected. This is shown on figure 2.
The power disconnected ($\frac{\Delta P_{GS}}{P_{GS}}$) can be approached by the cumulative distribution function of the normal distribution with parameters f and σ, in the interval [x; +∞]. This is given by the formula:

$$\frac{\Delta P_{GS}}{P_{GS}} = \frac{1}{\sigma.\sqrt[2]{2.\pi}} . \int_x^{+\infty} e^{\frac{-(y-f)^2}{2.\sigma^2}} . dy \quad (15)$$

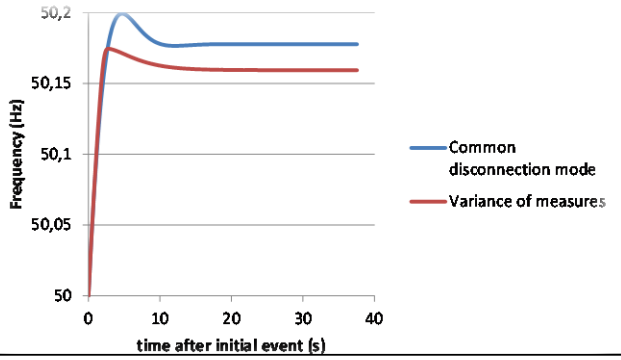
With $y \in \mathbb{R}$ and x= frequency disconnection set point.

FIGURE 2
Illustration of the effect of the distribution of the frequency measurements done by PV inverter on the disconnection rules



SECTION VII: RESULTS

FIGURE 3
Evolution of frequency for scenario 1 and 2



For the first scenario (common disconnection mode), the required primary reserve is 2150 MW.

When we simulate the second scenario (see the evolution of frequency in figure 3), we came to the value of 300MW! With other words, the progressive disconnection of PV inverter is almost sufficient to stabilize the frequency.

SECTION VIII: CONCLUSION AND FURTHER WORKS

These results show that the variance of the frequency measurements done by hundreds of thousand of devices have an important influence on the system response. If we take this effect into account, the distribution grid is resilient to this issue.

This paper calls for 3 different types of the future works.

The first work that can be done is to review the different assumption and, mainly the assumption 8. What could be the system behavior if the accuracy of the frequency measurement is better than 0,1 Hz.

The seconds one consists to verify these assumptions of the standard deviation of the frequency measurement by testing real inverter coming from the field.

For Belgium, these have to be put in service prior to 2012.

And finally, starting from the observation that deviation of measures may have important consequences on the system behavior. As we did for frequency, the same approach could be used to assess the impact of accuracy on power measurements. For instance, it is described in the new standard and new European requirements for generator (RfG) that, let say 50.2 Hz an output power droop is activated. This droop is an active power frequency response, decreasing the output power. But this droop function needs a local measure of the output power on which the question of the dispersion of the power measurement can also be asked.

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APPENDIX I: TABLE 1

TABLE 1
Definition and Frequency Performance target

reference	Subject	Value
f_0	Nominal Frequency	50Hz
f	Actual frequency	
Δf	Frequency deviation: difference between actual frequency and nominal frequency *(f-f_0)*	
Δf_{act}	Activation of primary control	+/- 20 mHz
$\Delta f_{act,max}$	Full Activation of primary control reserves	+/- 200 mHz
$\Delta f_{s,max}$	Maximum permissible frequency deviation in steady-state (steady state = actual frequency after 30 s)	+/- 180 mHz
$\Delta f_{d,max}$	Maximum permissible frequency deviation dynamic	+/- 800 mHz
RoCoF Max	Maximum Rate of Change of Frequency	2 Hz/s
RoCoF 30s	Rate of Change of Frequency after 30 seconds	0 Hz/s

APPENDIX II: COUNTRIES IN SACE

Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, Denmark (western part), France, Germany, Greece, Hungary, Italy, Luxembourg, Macedonia (FYROM), Montenegro, the Netherlands, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, and Switzerland