Operating a Low Inertia System

A System Operability Framework document

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nationalgridESO

Executive Summary

We at National Grid ESO are always looking at how to best operate the network, as we see reductions in system inertia. We have processes in place for managing each operability challenge. We are already looking to address the future challenges we see ahead of us as we transition to a zero carbon system.

Background

System Inertia is a characteristic of the system that defines how much energy is available in the rotating masses of all machines (generators and motors) that are directly coupled to the system. This inertia allows us to instantaneously balance any surplus or deficit in power. The rate at which frequency changes following a loss of generation or demand depends on the total system inertia. When inertia is low due to less energy being stored in rotating masses, the frequency changes faster and it is harder to manage.

Traditionally in the GB electricity system, the bulk of electrical energy has come from transmission-connected thermal power plants, including coal or gas fuelled generators. These generators have large rotating masses which contribute to system inertia. With the changing energy mix, renewable generators (such as wind and solar) have been replacing the traditional fossil-fuel generators to produce clean energy for GB consumers. However, these renewable technologies do not provide inertia and the total system inertia decreases.

There has been a continuous decrease of total system inertia observed in the GB power system. The data shows that inertia is declining and that the amount of time spent at low values is increasing.

Figure 1 shows the trend of average inertia across the next 10 years. We can see the trend of declining inertia is set to continue. It is therefore important to study the impact of such changes in system inertia on system operability and to investigate new tools and services to respond to new challenges.

In this report as part of the System Operability Framework, we will discuss the current approach of managing system inertia and future measures of ensuring we have appropriate tools when inertia is gradually decreasing. Carrying out and periodically reviewing minimum inertia studies as have fed into this document is also a requirement on NGESO stemming from article 39 of the System Operator Guideline (SOGL) European Network Code [1].

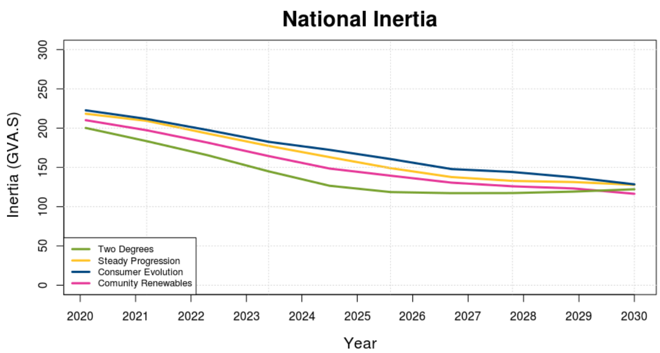

Figure 1: Inertia Trend to 2030

* Based of FES 2018 data

Current system inertia management

- The largest current inertia challenge is due to Loss of Mains Rate of Change of Frequency (RoCoF) relays
- This is currently managed through limiting the largest system loss or increasing inertia
- Our processes allow us to find the most economic and efficient way to manage RoCoF risk and and the minimum inertia requirement will vary over the short and long term

When the system sees an imbalance in generation and demand, the system frequency changes. System inertia directly links with the Rate of Change of Frequency (RoCoF) for any sudden change in generation and demand.

Currently some loss of mains protection relays used by distributed generators are set to the RoCoF limit of 0.125Hzs^{-1}. When RoCoF exceeds this limit, the relays could operate and distributed generators will be disconnected from the system. The principle of RoCoF protection operation is based on the assumption that an islanding event will result in the local frequency changing at a rate that is higher than the RoCoF that is expected to be seen on the total system under a range of normal operational conditions. RoCoF relays measure this rate within the generator's installation and once it exceeds the pre-defined threshold for the required period of time, the relay disconnects the generating plant from the network.

We currently manage system inertia to prevent the RoCoF loss of mains protection triggering when inertia is low. Most of the time we manage the largest loss in the system so that it will not result in RoCoF higher than 0.125Hzs^{-1} and subsequent loss of embedded generation as this is the cheapest solution. On other occasions, we may bring on more synchronous generators in a region for additional system inertia. In these circumstances, the additional synchronous machine will not only bring the benefit of increased system inertia but help deal with voltage and short circuit level issues.

When managing RoCoF risks we need to ensure we are acting consistently and economically. We do this

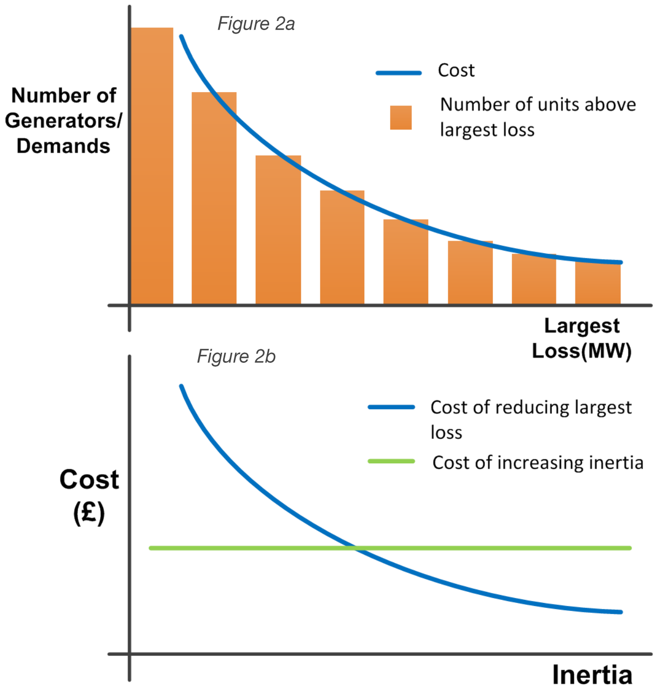

Figure 2a & 2b: Managing RoCoF Risk

by firstly calculating the largest loss the system can withstand. In most circumstances we can evaluate this using the swing equation below, meaning that for example, to secure a loss of 1000MW, we need 200GVAs of inertia with a RoCoF limit of 0.125Hzs^{-1}. The relationships within the swing equation are linear and easily scalable.

$$\Delta P = \frac{2H * RoCoF}{f_0}$$

f_0 is the starting frequency and in planning timescale it is assumed to be 50Hz.

Once we know our largest loss limit, we work out the number of units that need to have their output reduced to ensure we are below the largest loss level for known contingencies. This is illustrated in Figure 2a. As inertia declines, the largest securable loss also declines, but the number of generators or demand that are likely to generate above this value of increases. This means that as inertia declines and we need to de-load more units, the cost of managing largest loss grows. If we assume, as illustrated in Figure 2b the price of increasing inertia is reasonably constant, at a particular level of inertia the most economic option shifts from manging largest loss to increasing inertia.

Figure 3 shows a typical daily inertia profile and it can be seen that inertia is low between 12am and 6am compared to the evening peak. We analyse and forecast inertia at different times of the day in particular the low inertia period and we take actions both in planning timescale and real-time to ensure we operate the system in a safe and economic way.

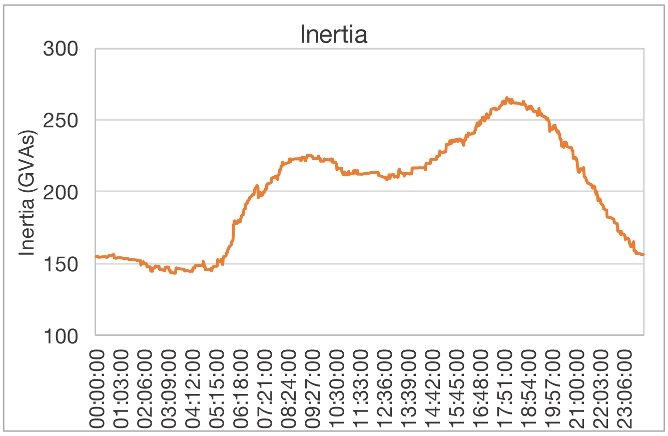

Figure 3: Daily Inertia Profile

9 August 2019 Incident

During the 9 August 2019 frequency event, system inertia was within the normal range at 210GVAs. This is equivalent to a largest loss limit of just above 1000 MW. However the rare and highly unusual set of circumstances meant that a loss of generation output exceeding what was secured for at the time occurred and this led to frequency deviating outside the limits. Measures to secure the system such as Low Frequency Demand Disconnection were deployed. This was not a low inertia event but an illustration of what can happen when the energy imbalance is greater than what was planned. For further information on the event, you can find the complete technical report on our website [2].

Future system inertia management

- Work is already underway to replace Loss of Mains relays which will reduce this system risk however, other operability challenges still remain.
- These include fast frequency deviations, LFDD and stability.
- Inertia is just one of the future operability challenges we face and all factors need to be considered together.

We are currently working with the electricity distribution companies to update settings for the RoCoF Loss of Mains protection relays from 0.125 to $1Hzs^{-1}$, with a definite time delay of 500ms, under the Accelerated Loss of Mains Change Programme [3]. This will allow us to increase the maximum allowable RoCoF over time as Loss of Mains will no longer be the limiting factor.

Once the work to replace Loss of Mains relays has been completed, inertia will still need to be a consideration in operability due to other factors such as: fast frequency response capability, Low Frequency Demand Disconnection scheme effectiveness, and system stability. Inertia in the future will need to be considered alongside other operability challenges such as short circuit level and demand inertia profile change.

Here is a short overview of these future operability risks and work that is ongoing to address them:

Fast Frequency Response

The system needs faster frequency response to balance the system and capture the frequency fall in a low inertia system. We need to open up the fast frequency response capability from new technologies such as wind, solar and storage solutions as well as demand side response to adapt to the increased volatility of frequency. Our approach to this is described in our Future of Balancing Services work [4] including the development of the new dynamic containment product.

The Enhanced Frequency Control Capability (EFCC) Project completed in 2019 investigated new ways to stabilise the electricity transmission system as the nation's energy becomes greener and progressively faster responses are required [5]. This will inform the development of our control systems which are likely to have to be adapted to ensure that the electricity system remains stable as increasingly fast response services are deployed on a system with reducing synchronous generation capacity.

Low Frequency Demand Disconnection

The Low Frequency Demand Disconnection (LFDD) scheme is designed to arrest frequency falls for extreme system events such as system splits and prevent a full system collapse. Demand will be automatically disconnected by LFDD relays when frequency drops below pre-defined limits to balance the system.

System frequency changes faster in a low inertia system and will trigger the pre-defined LFDD stages more quickly. There is the increased risk that multiple stages of LFDD will be triggered before the previous one can operate. This will increase the risk of tripping excessive demand, which may result in an over-frequency event after the initial low-frequency event. We have published the SOF report in 2017 outlining potential challenges of the LFDD scheme [6].

We have engaged with the stakeholders to assess and review the effectiveness of LFDD as inertia decreases and the spaces between stages will be designed to ensure the security of the system and also account for the low inertia scenario. In addition, in a system split event, regional inertia should also be considered as the LFDD scheme needs to be functional in each region.

Stability

As inertia declines so do other parameters that support stability such as short circuit level. We need to ensure the stability of frequency and voltage, and the ability of a user to remain connected to and to act to support the system. This is needed during normal operation, during a secured fault and after a secured fault.

With the decline of synchronous assets and increase of non-synchronous assets on both transmission and distribution networks, stability needs are evolving. Changes in where synchronous generation is concentrated across GB has the potential to influence the scale of regional variations in RoCoF and the ability of the system to stay synchronised if significant disturbances occur.

The Stability pathfinder project is currently underway and will set out what products and services are required [7]. This will look at inertia at the same time as other parameters like short circuit level to find what is needed to ensure stability.

Conclusions

Whole system inertia is generally decreasing over the next few years. Currently the main constraint for inertia management is the 0.125Hzs^{-1} limit of RoCoF protection used by distributed generation for islanding events after transmission faults.

Most of the time, we manage the system inertia by constraining the largest single loss of infeed so that the 0.125Hzs^{-1} RoCoF limit will not be exceeded. On other occasions, we increase the system inertia by bringing on synchronous generators when there has already been a need for voltage and fault level management in that area. Which method we use is dictated by what is most economic and efficient.

As the RoCoF loss of mains relays are being changed to the new setting, the RoCoF limit will not be the constraint for inertia management and frequency control in the future. Minimum inertia requirements will change over time and we see value in providing regular updates on our approach and engaging regularly with stakeholders on how this might develop.

In the future, other constraints such as fast frequency response services, LFDD scheme, and stability will come into play when managing the system inertia. We are already looking ahead to these challenges:

- We will explore the capability of fast frequency response products from new services and maintain the system inertia to an appropriate level.
- We will work with the electricity distribution companies to help review and monitor the effectiveness of the LFDD scheme as part of the system defence plan.
- We will continue our undertaking the Stability pathfinder project which will set out what products and services are required to maintain system stability - these include but are not limited to inertia.

References

[1] https://www.entsoe.eu/network_codes/sys-ops/

[2] https://www.nationalgrideso.com/information-about-great-britains-energy-system-and-electricity-system-operator-eso

[3] http://www.energynetworks.org/electricity/engineering/accelerated-loss-of-mains-change-programme.html

[4] https://www.nationalgrideso.com/publications/future-balancing-services

[5] https://www.nationalgrideso.com/innovation/projects/enhanced-frequency-control-capability-efcc

[6] https://www.nationalgrideso.com/document/87836/download

[7] https://www.nationalgrideso.com/publications/network-options-assessment-noa/network-development-roadmap

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