Assessment of Policy Options for Securing Inertia

Final report

Written by Artelys, Trinomics and Tractebel ENGIE.
Consortium led by Artelys
June 2025

EUROPEAN COMMISSION

Directorate-General for Energy
Directorate C — Green Transition and Energy System Integration
Unit C3 — Internal Energy Market

Contact: Elaine O'Connell
E-mail: *Elaine.OCONNELL@ec.europa.eu*

European Commission
B-1049 Brussels

EUROPEAN COMMISSION

Assessment of Policy Options for Securing Inertia

Final Report

Directorate-General for Energy

2025

EN

Authors

Nicolas Omont (Artelys)
Guillaume Lhermet (Artelys)
Alexandre Marié (Artelys)
Charlotte Pierre (Artelys)

João Gorenstein Dedecca (Trinomics)
Victor de Haas (Trinomics)
Robin Butzen (Trinomics)
Timo Van Delzen (Trinomics)
Luc van Nuffel (Trinomics)

Pierre Henneaux (Tractebel ENGIE)
Sajid Hocine (Tractebel ENGIE)

Contact person

Nicolas Omont (Artelys)
nicolas.omont@artelys.com

Disclaimer

The information and views set out in this report are those of the author(s) and do not necessarily reflect the official opinion of the Commission. The Commission does not guarantee the accuracy of the data included in this study. Neither the Commission nor any person acting on the Commission's behalf may be held responsible for the use which may be made of the information contained therein.

Europe Direct is a service to help you find answers to your questions about the European Union.

Freephone number (*):

00 800 6 7 8 9 10 11

(*) The information given is free, as are most calls (though some operators, phone boxes or hotels may charge you).

Manuscript completed in June 2025

June 18th 2025 version

Luxembourg: Publications Office of the European Union, 2025

PDF ISBN 978-92-68-30277-4 doi:10.2833/8332305 MJ-01-25-114-EN-N

Table of Contents

Abstract

Imbalances between injection and offtake lead to frequency deviations. System balancing relies on power reserves and defence plans, but these are based on frequency or Rate of Change of Frequency (RoCoF) measurements, which means they require a few hundred milliseconds to act. Right after a contingency, well-distributed inertia is therefore crucial to maintain RoCoF within acceptable limits, particularly to avoid system collapse (blackouts) during system split events.

With the energy transition, inverter-based resources (IBRs, e.g. solar, wind, batteries) are replacing traditional synchronous power plants, leading to a significant decrease in system inertia, and therefore a progressive decline in system resilience without mitigation measures. In addition to synchronous machines, synchronous condensers and IBRs with grid-forming mode associated to energy storage are potential technological solutions to provide inertia.

Policy options for securing inertia include market-based mechanisms, TSO investment, and revised connection requirements. These options are complementary. EU-level actions are recommended to define binding inertia targets and establish common parameters for a technology-neutral inertia product definition.

To safeguard a minimum level of system resilience, a few hundred GWs of additional equivalent kinetic energy is necessary in the mid- to long-term, which could represent investments up to €2-4 billion annually. Various options for allocating the costs of inertia securement can be considered.

Executive summary

Challenges to ensure future electricity system stability and inertia needs

Power systems balancing involves numerous mechanisms which take place at different time horizons. Imbalances between injection and offtake, which result from ordinary variations of the load and of the intermittent generation or from contingencies (e.g. failure of assets), impact frequency. Frequency drops after a decrease of generation and increases after a decrease of load levels. Power reserves are activated to stop the frequency deviation and restore frequency to its nominal value of 50 Hz in Europe. The power adjustment provided by balancing reserves is not instantaneous. Assets providing the fastest reserve in Continental Europe (Frequency Containment Reserve) typically start within a few seconds and are fully activated in 30 seconds. In exceptional situations, defence plans (e.g. load shedding) can be activated faster than balancing reserves, in around 500 ms.

Both reserves and defence plans activations are based on frequency or Rate of Change of Frequency (RoCoF) measurements. RoCoF represents the speed at which the frequency changes (in Hz/s). Frequency measurements of reasonable quality cannot be made over a window shorter than 100 ms. Being the derivative of frequency, accurate enough RoCoF estimation requires even more time, usually over 200 ms. Overall, taking into account the time needed to process measurements and act while keeping some operational margin, it cannot be expected that automata based on frequency or RoCoF measurement can act in less than 500 ms.

Immediately after a contingency, the (system) RoCoF is proportional to the contingency size and inversely proportional to the system inertia. **During the 500 first milliseconds, guaranteeing a sufficient level of inertia in the system is the only way to keep the RoCoF within an admissible range**. Indeed, no other action is fast enough to be active during this initial window. The exact value of the window (between 200 ms and 500 ms) is secondary in the determination of the inertia need. Indeed, even with very fast action in 200 ms, the first hundred milliseconds would still need to be covered by the system inertia alone.

Technically speaking, the inertia is the property of the system that enables a power adjustment proportional to the RoCoF starting as quickly as within 10 ms after an imbalance occurs, in order to cope with it. It is lasting as long as the frequency is not stabilised, therefore usually up to hundreds of milliseconds afterwards. The reaction is independent of any control system, in particular it happens without any frequency measurement. Historically, inertia relied on the natural adjustment provided by extracting power from the kinetic energy of synchronous machines (generators, condensers, motors)[1].

With the energy transition, assets that are connected to the grid via power electronics inverter-based resources (IBRs: photovoltaic power plants, wind turbines, batteries, …) are expected to represent a much larger share of power generation, replacing traditional assets such as gas- or coal-fired power plants. However, these assets do not provide inertia (with traditional grid-following inverters). **The inertia of the system is therefore expected to significantly decrease in the future** (ENTSO-E calculations based on TYNDP2022 NT scenario show that the median inertia constant *H* of CE synchronous area is expected to decrease from above 5 seconds in 2019 to below 3 seconds in 2030).

Two key issues have to be considered to limit the consequences of a lack of inertia on system stability:

- **Value of Nadir** (minimum of frequency reached), as too low nadir can lead to load shedding and/or generation tripping, and, in the worst case, system collapse. In some cases, the value of the Zenith (maximum of frequency reached) can also trigger unacceptable consequences.

[1] Or injecting power in case of a positive RoCoF corresponding to an excess of generation.

- **Value of RoCoF** (rate of change of frequency), as high RoCoF can result in the tripping of grid components.

In the Continental Europe Synchronous Area (CE SA), ENTSO-E indicates that as long as the instantaneous RoCoF remains limited, defence plans should be enough to ensure survivability of the system (i.e. avoiding a total blackout). The **key driver of inertia needs is therefore the system operation limit of 1 Hz/s RoCoF** (as in case of too high RoCoF, defence plans will not be able to react fast enough). This system limit has been defined by ENTSO-E based on an analysis of past events, equipment limits, and frequency and RoCoF measurement limits. In particular, frequency cannot be measured instantaneously. Furthermore, RoCoF is not uniform and can be significantly higher locally immediately after the contingency. However, the impact of this limit on the needs is very significant as they are roughly inversely proportional to the limit (doubling the RoCoF limit would divide the needs by two). Even if the current Network Code Requirement for Generators (NC RfG) seems to have settled to this limit of 1 Hz/s, we recommend that further studies are performed to evaluate as precisely as possible the optimal trajectory limit up to the long term (2050), taking into account the risks associated to a higher RoCoF limit, as well as the feasibility and cost to upgrade or retire equipment that would be impacted by a higher RoCoF limit.

As the European power system is very large, **such high RoCoF is not expected in normal interconnected operation but can happen during system split events**. A system split occurs when the system is unintentionally separated into two or more asynchronous islands, which interrupts the power flows between two areas, thus inducing an imbalance between generation and load in one or more of the resulting areas. Each isolated area must suddenly operate on its own to compensate for the lost power exchanges. These power flows are getting increasingly larger, as a key feature of the energy transition in Europe is the integration of energy markets, thus increasing the impact of the splits. After the split, the frequency can change rapidly (high RoCoF), potentially leading to generation tripping or, in the worst case, to blackouts.

System splits are out-of-range contingencies, meaning that it is allowed to rely on defence plans to address their consequences in terms of Nadir (or Zenith). However, as said before, load shedding is not fast enough to limit the initial RoCoF.

A key issue is the definition of the level of risk to cover or the target resilience level of the system, as it is impossible to safeguard against all imaginable system splits. **ENTSO-E proposes to assess system resilience based on the number of avoided Global Severe Splits** (GSS), which are split cases where there is a risk of a blackout of the entire relevant Synchronous Area (as in the case of GSS there is no neighbouring grid able to promptly restore a blacked-out subsystem). ENTSO-E indicates that the accepted level of risk resilience and the accepted risk of blackout should be agreed on by all stakeholders and relevant institutions. The proposed system resilience target, which focuses on the survivability of the system but does not eliminate all risks of blackout, seems reasonable to us. Indeed, while system splits are exceptional, they have happened in the past and seem to be likely to happen in the future with a probability high enough to justify action (given the decreasing levels of inertia and increasing integration of European power markets – which does not mean that limiting market integration and renewable integration are appropriate solutions to recover system resilience). This justifies costs for inertia procurement in line with the cost range estimation performed in this study to avoid blackouts of the full Continental Europe Synchronous Area which could last hours or even days.

The end of section 2.2 (page 33) contains an overview of the links between what is discussed in this study and what happened during the recent Iberian blackout (although very little information is available as of now).

In a recent study, ENTSO-E evaluated inertia needs based on prospective scenarios modelling, considering a set of potential splits. **A key recommendation from their analysis is to define a minimum inertia constant *Hmin* requirement expressed as an equivalent kinetic energy value of**

2 sMW/MVA that each country should fulfil at least 50% of the time. ENTSO-E analysis shows that adding equivalent kinetic energy to meet this requirement would allow to satisfy around 98% of global severe splits considered, although in about 80% of cases at least one island would have a RoCoF higher than 1 Hz/s. It should be noted that the assessment of inertia needs faces several challenges, including the complex monitoring of existing inertia and the difficulty in estimating inertia provided by loads. While the choice of this initial uniform target is a reasonable first step, further studies and methodology developments would be needed to set per country optimal targets. A balance needs to be struck between defining an initial target to encourage the deployment of inertia capacities in newly installed relevant assets, and the need for further studies to define the target in the most relevant way possible.

Additional quantitative evaluations of need were carried out for this study, based on TYNDP2024 hourly dispatch data and conservative inertia constants. Available hourly equivalent kinetic energy has been calculated to determine the additional GW·s of inertia required to cap RoCoF at 1 Hz/s for all hours, for imbalances resulting from a 3 GW loss and four historical splits (Italy 2003, Three-Islands 2006, Balkan 2021, Iberia 2021). While ENTSO-E's analysis mapped the additional kinetic energy requirements (inertia) on the basis of 450 hypothetical border splits under TYNDP2022 2030/2040 scenarios, this study extends the horizon to 2050 and focuses on historical splits. The need has been evaluated to limit RoCoF on both sides of the splits, and not only avoid GSS situations. **While these two methods show significant differences, the results on needs are of the same order of magnitude (a few hundred GW.s)**. This modelling work shows that the peak additional inertia need is 299 GW·s in 2030, increasing by around 20 % in 2040 (e.g. Iberia 97→142 GW·s; Italy 299→332 GW·s), before stabilizing in 2050 scenarios (although the average inertia requirements are higher). Sensitivity analyses were carried out on topics such as PSH contribution, higher inertia constant (H = 4 s) and higher RoCoF threshold (to 1.5 Hz/s, which can halve peak needs). These analyses show that Continental Europe might require several hundred GW·s of additional equivalent kinetic energy to ensure that the RoCoF remains below 1 Hz/s in the event of a system split.

ENTSO-E stresses that **achieving the minimum resilience target depends on the amount and regional allocation/distribution of additional inertia** in the Continental Europe Synchronous Area (CE SA). Indeed, contrarily to reserves such as FCR, **a key specificity of inertia is that it cannot be easily transferred across borders** since it should enable at least part of the system to survive a system split. We think that this, however, do not mean that no inertia at all could be exchanged between countries with well-connected systems. ENTSO-E asserts that, as system split events cannot be anticipated, the available inertia should always be well distributed throughout the system, although the exact uniformity need has not been defined yet. System splits within a country are also a possibility. The geographical repartition of devices capable of providing inertia can also help solve other local issues like short circuit level and voltage support. The most appropriate mix of solutions may depend on country-specific grid and markets conditions. While reasonable, these assertions could be refined with further studies, by determining the splits that are likely enough to be considered. This might help to define sets of countries for which it would be interesting to study the potential benefits of exchanging inertia.

Frequency stability (related to inertia) is not the only stability challenge that the system faces. Voltage stability issues, which have consequences at the local level, can also arise from changing load flow conditions, which is amplified by the development of variable renewable energy. The reduction of conventional power plants use also means a reduction of short-circuit levels as these plants contribute to the fault current necessary for protective devices to function correctly. This affects protection system coordination. These issues are out of the scope of this report. However, solutions to these other stability issues, such as synchronous condensers or IBRs with Grid Forming Mode (GFM), often also provide inertia or could provide it (e.g. GFM-based IBRs with storage). By tackling frequency stability challenges, a necessary foundation for the system's resilience is established without restricting any solutions that might also be required to tackle other system stability issues. The coordination of the procurement of solutions for all these issues should therefore be aimed for.

ENTSO-E advocates that, as soon as possible, any device that can provide inertia and will be connected to the CE grid – such as Power Park Modules (PPMs), STATCOMs, and synchronous condensers connected for system strength/voltage needs – shall be equipped to provide inertia by using GFM converters. We think that considering inertia as a by-product when TSOs procure new assets or services is important, as it will not always come automatically (a small energy storage of a few seconds is necessary for GFM converters to provide inertia, the flywheel of synchronous condensers could be larger to provide more inertia, …).

Existing and emerging technologies and approaches to secure inertia

There is no widely agreed definition of a technologically neutral inertia service, with many options as shown by our review of existing mechanisms. In any case, a very fast reaction time is required to ensure RoCoF stability during the first 500 ms (initial RoCoF measurement window), meaning that technologies based on frequency measurements cannot provide this initial reaction that has to be provided by the inertia service to ensure system survivability. Such technologies could however provide fast reserve, which would enable to limit load shedding during extreme events such as system splits.

Chapter 3 analyses three main technologies capable of supplying inertia to power systems: synchronous machines, induction machines, and inverter-based resources (IBRs).

Induction machines contribute to an asynchronous inertia with delayed response and should not be further considered as a relevant solution due to limited impact on the initial RoCoF.

Synchronous generators have historically been the main providers of inertia. Synchronous condensers are now increasingly deployed for inertia services, especially the ones equipped with flywheels to boost inertia constants up to 7-8 seconds (and sometimes even 15 seconds). Synchronous condensers have high technological readiness levels (TRLs of 8–9), though investment costs vary widely depending on configuration, ranging from approximately 18 to 55 k€/MWs (and equivalent O&M costs). Retrofitting existing generators with clutches is a cost-effective alternative (around 60% of the investment cost of new synchronous condensers) with shorter lead times.

Inverter Based Resources (IBRs) with grid-following mode are limited by response delays and are not currently suitable to provide a sufficiently fast inertial response, i.e. as quickly as in 10 ms. On the contrary, **IBRs with grid-forming mode (GFM) have a near-instantaneous response, making them strong candidates for synthetic inertia**. Existing grid-following converters of existing battery energy storage source (BESS) units, wind farms and PV parks can be transformed into grid-forming converters with the addition of a small energy storage like an ultra-capacitor. Alternatively, dedicated converters with an ultra-capacitor but no energy source can be installed. They are called e-STATCOMs. These devices currently have lower TRLs (around 7–8) and are in earlier stages of commercial deployment. The investment cost appears to be slightly higher than for synchronous condensers, but O&M are expected to be much lower.

GFM-based IBRs have some technological limitations that synchronous generators do not have. The first one is that their short-term overload capacity is very limited so that their power output will be capped if the RoCoF is too high, while synchronous condensers are usually considered as having a RoCoF limit high enough to be neglected. The second one is that they need a small energy storage (in tens of seconds of the maximum power to be delivered as part of the inertia service) that should be dimensioned to a value smaller than the kinetic energy stored in a Synchronous Generator in order to minimize costs. At least these two limitations should be factored in a technology neutral definition of an inertia services that balances the needs of the system and the possibility that GFM-based IBRs can provide it at a reasonable cost.

Approaches to secure inertia and recover costs

Chapters 4 and 5 identify and assess policy options for securing sufficient system inertia and recovering the associated costs, respectively. They assess these questions from an **EU perspective**, with a focus on analysing the advantages and disadvantages of the options, the issues which arise for coordination at the EU level, and proposing possible actions for introducing binding EU requirements or promoting cooperation through other means.

This study considers **three policy options to secure inertia**: use by TSOs of a market-based mechanism for procuring inertia (and possibly concurrently other ancillary services), investment and ownership in inertia-providing assets by the TSOs themselves, and revision of connection requirements for generators, storage or other users, with a focus on the first two options. **TSOs are required to procure ancillary services, which may include inertia, using market-based mechanisms in a non-discriminatory manner**, unless the NRA provides a derogation. Market-based approaches are therefore the required (unless a derogation is provided) and preferred option, fostering competition, cost-efficiency, and technological advancements but introduce complexity, higher transaction costs, and possibly higher uncertainties regarding long-term stability and adequacy, as there is a risk that the market may not meet the appropriate level of inertia needed. TSO ownership provides direct control over investments and easier integration into network development planning, but comes with financial burdens to TSOs, potential economic inefficiencies - as TSO ownership does not allow to leverage market-owned assets, might lead to over-dimensioning of inertia needs at the regional/EU level as cross-border sharing of inertial resources can be more difficult, and provides inertia at all times, even when market assets dispatched in spot and balancing markets might already provide sufficient inertia.

Most importantly, the **three policy options assessed are rather complementary than mutually exclusive.** The revision of connection requirements serves to enhance the capabilities of new and possibly existing network users, both reducing inertia needs, by for example increasing RoCoF withstand capabilities, as well as potentially increasing the network users' abilities to provide inertia. Then, procurement of inertia services from market parties as well as deployment and operation of assets by TSOs can both serve to meet remaining inertia needs.

However, while the principle of technology-neutrality should be pursued in securing sufficient inertia, different technologies for inertia provision can entail ownership by either network operators or market parties (although some technologies can be owned and operated by either). But the processes for securing inertia from network operator- vs market-owned assets are very different (market-based procurement mechanisms vs regulatory approval of network operators' investment plans). Moreover, the lead time for the deployment of new inertia-providing resources (whether owned by market parties or network operators) needs to be considered, which can be of 3 years or more for synchronous condensers. Hence, **a choice must be made on how and in which sequence to combine network operator- and market-owned assets**.

Regulators will need to consider how to meet the requirement for TSOs using market-based mechanisms to procure inertia services (unless a derogation is provided), considering the fact that either market parties or network operators will need reasonable certainty and time to invest in new resources, whether that is for example a new synchronous condenser deployed by a network operator or the upgrading of a market-owned HVDC converter. Furthermore, given various technologies are able to provide not only an inertial response but also other services such as voltage control, the framework needs to **consider how to enable utilisation of the assets for multiple services (value stacking), whether network operator or market-owned.**

Provision of inertia services in dedicated procurement mechanisms by existing or new assets should be remunerated, and we do not recommend obligating certain users to provide inertia to the system, either for free or against remuneration at administratively-set prices. It can lead to resource allocation inefficiencies, obligating parties with higher marginal costs for provision of inertia, and it discriminates against these actors, and furthermore can deprive other potential inertia service providers of revenues.

Requiring network users to be technically equipped to provide such services could still be an option left for national authorities and system operators, as recommended by ACER in its proposed amendments to the connection requirements network codes. TSOs should be required to conduct a qualitative cost-benefit analysis to assess the matter, and eventually submit a proposal for approval by the NRA before any such requirement is introduced. Market parties and solution providers have however expressed concerns over the introduction of any such requirements at the national level, deeming more cost-efficient to focus on market-based mechanisms to incentivise inertia service provision.

Chapter 5 includes an estimation of costs required to meet future inertia needs in the European Synchronous Area, based on the evaluation of inertia need from this study. Two technologies are considered to provide an upper bound of costs: synchronous condensers with flywheels and e-STATCOMs. While synchronous condensers incur higher total annualized costs (up to €6.1k/MWs.year), e-STATCOMs offer a more cost-effective alternative (€3.1k/MWs.year), although with greater uncertainty due to their lower maturity. **We estimate that the long-term cost of procuring system inertia for the Continental Europe Synchronous Area could be up to €2–4 billion per year,** but there is still significant uncertainty around the actual future costs of securing enough system inertia and costs could be significantly lower if certain strategies are implemented.

The study also considers three **options for allocating the costs of inertia securement**: charging electricity generators which do not provide inertia, charging a broader group of network users, or utilising existing balancing reserves-related charges. **Cost recovery from a broad groups of network users is considered the preferred option**, as it offers the greatest flexibility, distributes costs between a larger group of actors and, if well-designed, leads to the least amount of distortion.

Nonetheless, **there is not yet a clear argument for EU-level mechanisms for procuring inertia services nor for binding harmonisation of inertia network charges.** The eventual exchange of inertia resources among control areas will be complex, and there are technical limits to the extent it is possible. Hence, it is not clear whether the potential benefits of exchange of inertia resources outweigh the associated costs and complexity. On tariff structures, the costs for securing inertia should be lower than TSO balancing costs, and therefore the **risks for distortion of competition between generators of different Member States is deemed limited** (possibly unless inertia costs are recovered in the future solely from generators which do not provide inertia).

EU-level recommendations and timeline

The impacts of any new regulatory measure will only be observed at the earliest close to 2030, given the policy cycle for proposing, agreeing on and implementing appropriate EU-level provisions takes several years. **Inertia levels in the Continental Europe Synchronous Area are falling and additional inertial resources are deemed necessary already by this horizon,** increasing towards 2040-2050, as indicated above.

The **development of a coherent framework for securing inertia at the EU and national level is a complex matter**, which needs to consider appropriate procedures for:

- Revision of connection requirements where appropriate
- Assessment of inertia needs
- Allocation of identified needs across control areas
- Forecasting, short-term measurement and ex-post evaluation of actual system inertia levels
- Securement of inertia to make up for identified gaps from network operator or market-owned assets
- Inertia securement cost allocation between control areas and network users

A number of areas for action at the EU level exist, either as binding measures or promotion of cooperation between the relevant actors. In addition to measures proposed by ENTSO-E in its January 2025 paper, **we identify the following recommended actions**:

- ENTSO-E, EU DSO Entity, ACER, European Commission: Definition of a methodology for defining binding inertia targets and national ex-post evaluation of inertia levels, possibly as amendment to the System Operations Guideline
- European Commission: Consideration of the need for establishment of common parameters for inertia product definition (with multiple products possible)
- European Commission or ACER: Non-binding guidance on use of market-based mechanisms for inertia procurement, including a common approach from all NRAs
- ENTSO-E or commissioned by European Commission: Techno-economic cost-benefit analysis on potential benefits, costs and limitations of inertia resource exchanges, modelling the impact of scheduling our of merit order synchronous units and/or reduction of exchanges
- ACER: Assessment of inertia cost recovery through tariff charges in the next bi-annual electricity network tariffs practice report

Therefore, we recommend immediate actions at the EU level but additional analysis is needed particularly regarding eventual regional exchange of inertia resources, while additional inertia resources are needed already in the 2030/2035 timeframe with needs increasing towards 2040/2050. **A timeline for introduction of regulatory measures could thus comprise:**

- In the **short-term (impacts by 2030/2035)** the European Commission, ACER, ENTSO-E and the EU DSO Entity move forward estimating inertia needs per synchronous area and defining national targets, with national authorities and TSOs introducing market-based mechanisms for inertia service procurement where needed (following non-binding EU guidance on the design of such mechanisms);
- In the **medium/long-term (impacts by 2040/2050),** further work is conducted to assess the costs, benefits and limitations of regional inertia exchange, and EU and national actors move forward to securing additional inertia resources (at the regional or national level depending on outcomes of the analysis) to meet enhanced reliability targets.

Glossary of acronyms

BESS: Battery energy storage source

CE SA: Continental Europe Synchronous Area

E_{kin}: Kinetic energy (generally used as the equivalent kinetic energy of the power system)

e-STATCOM: cf. STATCOM

FCR: Frequency Containment Reserve, in Europe

FFR: Fast Frequency Reserve (type of very fast reserve, which does not currently exist in CE SA)

GFL: Grid following (type of power converters)

GFM: Grid forming (type of power converters)

GSS: Global severe splits (splits where both islands experience a RoCoF higher than 1Hz/s at the centre of inertia)

GWs: Giga Watt seconds (unit for energy). Inertia is sometimes expressed in GWs (as equivalent kinetic energy), but also often via an inertia constant **H** expressed in seconds (or sMW/MVA, which is equivalent to seconds).

HVDC: High voltage direct current transmission lines

IBR: Inverter-based resources, for example solar power parks, wind turbines and batteries connected to the grid through power electronics to convert direct current (**DC**) to alternating current (**AC**), synchronised to system frequency.

Nadir: Minimum frequency reached after an imbalance (opposed to zenith)

NRA: National regulatory authorities (**ACER** being the European agency for the cooperation of energy regulators)

O&M: Operation and maintenance (generally referring to associated costs)

PFR: Primary Frequency Response (e.g. FCR)

PPM: Power park module

RES: Renewable energy systems/sources

RoCoF: Rate of change of frequency (frequency derivate, in Hz/s)

SA: cf. CE SA

SC : Synchronous condenser

sMW/MVA: cf. GWs

STATCOM: Static synchronous compensator. **e-STATCOM** integrate short-term energy storage to provide inertial response in addition to dynamic reactive power

TSO: Transmission system operator (**ENTSO-E** being their European network for electricity), their equivalent for the distribution network are **DSO**s.

TRL: Technology Readiness Level, this method is used to measure technology readiness levels on a scale from 1 (low maturity) to 9 (most mature technologies)

TYNDP: Ten-year network development plan. It is developed every two years by ENTSO-E and is based on scenarios, in recent years: National Trends (**NT**), Global Ambition (**GA**) and Distributed Energy (**DE**).

UFLS: Under Frequency Load Shedding

Zenith: Maximum frequency reached after an imbalance (opposed to nadir)

1. Introduction on inertia

To meet their energy and climate objectives, EU Member States have embarked on an energy transition aimed at reducing the share of fossil fuels in their energy mix. This translates into the activation of two levers that profoundly transform the power system:

- A reduction in the share of fossil energy in the electricity generation mix,
- The massive electrification of energy end-use.

In order to meet this growing demand for electricity while reducing the use of (unabated) fossil-fuelled power plants, the role of wind and photovoltaic power is set to significantly increase.

This profound transformation of the power system requires a substantial review of the way to ensure its stability and security. In particular, the initial reaction of the power system during the first hundred milliseconds after a perturbation will be deeply impacted. Indeed, the power system is usually in a steady state with production equal to consumption. In case an imbalance appears, the system becomes unstable. The stability of the system historically relies on the natural response to imbalances – so called inertia – provided by the kinetic energy stored into the rotating masses belonging to the synchronous alternators and motors connected to the grid. However, wind and photovoltaic energy are not connected to the grid through synchronous alternators but through power electronics that convert DC current provided by the renewable source into AC current that can be injected into the grid[2]. The generation units that are connected to the grid through these DC-to-AC power converters are also called IBR (Inverter Based Resources).

This study intends to develop the understanding on the future stability challenges and inertia needs in the European electricity system (chapter 2), the analysis of existing technologies and approaches to secure inertia (chapter 0), and the assessment of options to secure inertia (chapter 4) and recover associated costs (chapter 5) from a socio-economic perspective. Various approaches are considered, including TSOs investing in and operating relevant technologies, technical requirements imposed on assets connected to the grid, and procurement of inertia services from market parties.

1.1. Role of inertia in the power system stability

The mathematical equations describing the role of inertia in the power grid are beyond the scope of this report, however, an analogy with a physical system composed of a road, a bike and a rider allows to get an intuition about the phenomena. It is summed up in the table below.

Table 1-1: Role of inertia in power system frequency stability and analogy with a biker

Phase	Cyclist riding a bike	Power system frequency stability
Nominal / steady state	The bike moves at a constant speed (on level ground, the force provided by the cyclist is equal to the friction of the wheel and air resistance).	The frequency of the power system is stable at $f_0 = 50\ Hz$ (electrical power injected into the system and withdrawn from it are equal).
Contingency	Additional friction is introduced (e.g. gravel on the road, or sudden headwind).	A contingency occurs (e.g. failure of a large generation unit or a line). The most constraining contingency that the system should face without significant impact on the users is called the “dimensioning contingency”.

[2] This is the general behaviour. Some wind generation technologies are partially or completely connected to the grid using synchronous generation.

Source of inertia	Cyclist's mass	Synchronous machines' rotating mass
Direct consequence of the contingency	The bike slows down. The deceleration (the rate at which the bike slows down) depends on the cyclist's mass (kinetic energy) and on additional power needed due to the increased frictional force. If the incident is too violent (e.g. the front wheel is stopped), the cyclist might go over the bars before any remedial action.	The frequency decreases (machines rotate slower). The Rate of Change of Frequency (RoCoF) depends on system inertia (E_{kin}) and change in power (ΔP contingency). $RoCoF = \frac{\Delta P * f_0}{2 * E_{kin}}$ If the RoCoF is too high (typically over 1 Hz/s at the centre of inertia), assets might disconnect for their own protection and a blackout may occur, before any remedial action can take place.
Remedial action	To recover speed, the cyclist pedals harder (e.g. by cycling out of the saddle) to provide more mechanical power to the bike. In critical situations, some bikers could in theory adjust tyre pressure to reduce friction (some off-road vehicle can do this)	Power reserves (e.g. FCR – Frequency Containment Reserve) are activated to restore frequency. More mechanical power is delivered to the synchronous machine. In critical situations, it is also possible to activate the defence plan. In particular, it can quickly reduce the electricity consumption thanks to underfrequency load shedding automata.
Delay before remedial	The cyclist does not instantly take remedial action, as he/she must first acknowledge the fact that he/she is slowing down and then react. He/she only has a limited timeframe to recover speed, as the minimum speed reached depends on his time reaction. If the speed drops too low, the bike will fall. The time he/she has depends on how fast he/she slows down (and therefore on his weight and to the addition friction).	The reaction is not instantaneous, as frequency deviation must be first measured, and then power plants involved in FCR take time to react (e.g. to send more steam to the turbine, which takes second because large valves have to be opened). In continental Europe, the fastest reserve is FCR (the requirement is that power equivalent to the dimensioning contingency is delivered within 30s, and half within 15s). The reaction must be fast enough, as the minimum frequency reached (nadir) depends on reaction time. If frequency drops too low, a blackout may occur. The time available for reaction depends on RoCoF, and therefore on system inertia and the amount of lost power.

The analogy allows to understand that:

- The initial reaction to the perturbation thanks to inertia is not even automatic: it is built in the design of the system. It leaves enough time to the reaction based on automata that sense, process information, and act, to happen.
- The bike is the equivalent of the lines and transformers of the grid. Their inertia is neglectable (the grid is the equivalent of a very light bike). As a result, at any time, they are "balanced": the power in is equal to the power out (the power in through pedalling is equal to the power out through friction).

With this in mind, let's take a closer look at what happens to the electrical system after a contingency.

Figure 1-1 below indicates the different components of load and generation after a power unit loss (the share of the contingency and the various components is not realistic and has been chosen for representation purpose):

- In the steady state, the system is balanced: load is equal to the generated power ($L^0 = P^0$).
- Right after the contingency (with a reaction time below 500ms), large rotating machines (conventional generation and some consumers) and some other assets using GFM converters continue to balance the system thanks to power withdrawn from an energy storage proportionally to RoCoF: remaining power units provide their former power generation ($G^1 = G^0 - G^{lost\ unit}$) and additional power from their inertia. The actual power withdrawal (L^1) decreases as some loads provide some inertia.
- After a few seconds, load and generation are balanced thanks to additional generation power resulting from the activation of Frequency Containment Reserve (within 30 s). For design reasons, the nominal frequency is not fully restored by FCR. As a result, the load and generation (L^2, G^2) is slightly different from the initial load and generation (L^0, G^0). FCR activation almost equilibrates both as its activation is proportional to frequency imbalance ($L^2 = G^2 + FCR$).
- Within 15 min, Frequency Restoration Reserves (FRR) are activated, enabling generation and consumption to be balanced according to schedule ($L^0 = G^0 - G^{lost\ unit} + FRR$)

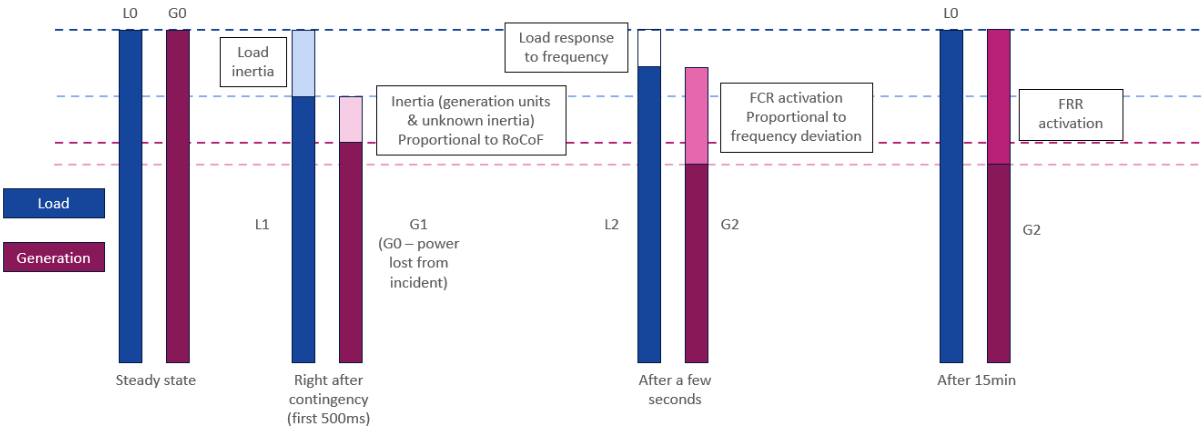


Figure 1-1: Illustration of the evolution of load and generation after a contingency

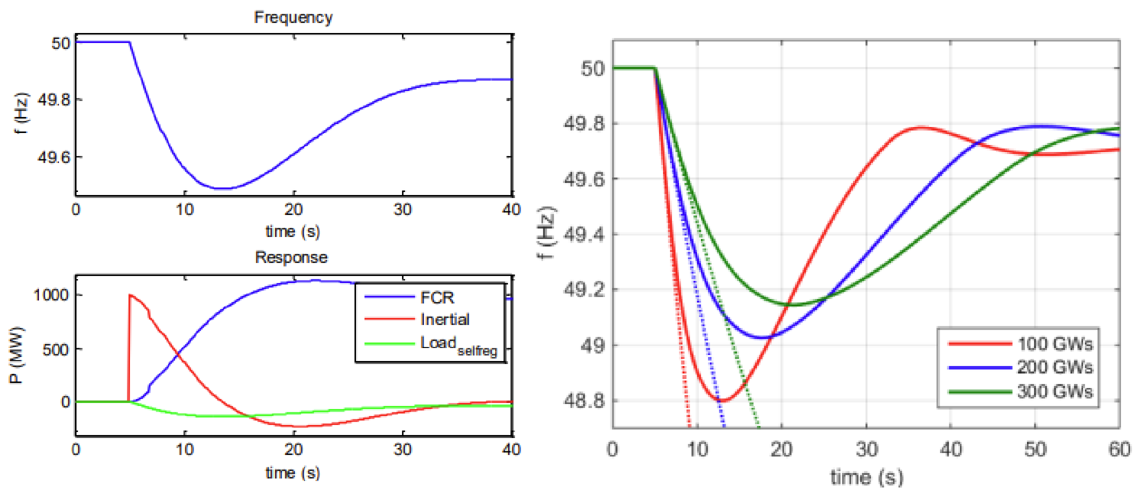


Figure 1-2: Left graphs: frequency after a contingency (up) and associated inertial and load and FCR responses (bottom). Right graph: effect of the amount of kinetic energy on the behaviour of frequency after a loss of generation with FCR (solid lines) and without (dotted). Source: ENTSO-E [3]

The key point to take away from Figure 1-1 and Figure 1-2 on the sequence of events and frequency response is that inertia is the physical quantity that allows the system to be stable during the first hundred milliseconds after a contingency, pending the implementation of remedial actions acting in second(s). As seen on the Figure 1-2 (right), the more inertia present in the system (in GWs), the slowest the frequency decrease (i.e. RoCoF is more limited). Inertia does not stop the fall of frequency but slows it and gives time for FCR to be activated. Only FCR stops the drop, typically between 10 and 20 seconds after the contingency occurs (in some systems, an additional fast reserve FFR acts faster than the European FCR). As the cyclist-bike falls if the speed is too low, the system will black out if the frequency drops below a given threshold (i.e. if the minimum frequency, also called “nadir”, falls below 47,5 Hz) because most generation units will suddenly disconnect to protect themselves. Therefore, if there is not enough inertia, a black out will occur before the defence plan is activated. It is also not the role of inertia to bring frequency back to its normal state (it is the role of other reserves such as FCR and FRR). This report focuses on inertia, not reserves.

The role of inertia is key during the firsts hundred milliseconds because current defence plan automata cannot act quickly enough and avoid RoCoF above 1 Hz/s (only inertia can). Indeed, they rely on frequency measurements that cannot be performed so quickly (the best devices (PMUs – phasor measurement units) cannot measure a reliable frequency in less than 100 ms). For longer delays, lack of inertia could be compensated by faster reserve (currently an activation delay of 3 seconds is tolerated for FCR, hopefully not used by all units).

While useful, this short introduction based on the biker metaphor has some limitations. Firstly, the power system looks like attaching many bikes altogether, but these ties are not rigid. Therefore:

- When the front wheel enters the gravel road (e.g. a loss of generation unit in Estonia), only the front biker provides inertia: the other bikers continue unaffected for tens of milliseconds or more. For power systems, a unit in Portugal will not feel any drop of frequency in Poland and will not provide additional power. As a result, the deceleration of the first biker may well be significantly higher than the average deceleration of bikers while only this average speed/frequency is explained by the presented model. It is a reasonable assumption to study FCR because frequency of all units is somewhat similar (except if interarea oscillation occurs, but classical means to dampen them exist), but it is not enough for the first hundred milliseconds.

[3] Graphs from ENTSO-E report on future system inertia in the Nordics [Link]

- If the perturbation is too large, then the ties between the bikes may break for various reasons so that two or more subsystems are formed (i.e. all AC lines between the subsystems are opened). Each subsystem will have to recover stability on its own: not only the initial RoCoF is different, but also the final frequency.

Secondly, reaching a frequency below the admissible minimum is not the only event to avoid:

- Symmetrically, a maximum admissible frequency exists. Bikers will stop pedalling if the bike goes too quickly. Though it usually restores frequency, too many generation units may disconnect so that the result can be an under-frequency event that may lead to a black out. Loads may be disconnected too.
- The RoCoF itself should be limited. Indeed, some protections for anti-islanding disconnect generation if the RoCoF is too high. They are based on frequency measurement so they are usually slow (activation in roughly 500 ms), but the amount of inertia should be enough to provide a low enough average RoCoF even if the initial RoCoF is higher. Synchronous machines also have RoCoF limits, though a short-circuit close to the power plant is an event that causes more mechanical stress to the synchronous machine than usual RoCoF[4].

It is therefore key to assess the need for inertia, which depends on the acceptable level of risk (what type and size of incident the system must withstand). Two key issues have to be considered to limit the consequences of a lack of inertia:

- **Value of RoCoF** (rate of change of frequency), as high RoCoF can result in the tripping of grid components (the bike analogy would be that the wheel could break)
- **Value of Nadir** (minimum of frequency reached), as too low nadir can lead to load shedding and/or generation tripping, and, in the worst case, system collapse (the bike analogy would be the minimum speed up to which the bike would still roll without falling over).

1.2. Impact of power electronics on inertia

Historically, RoCoF-based power output has been provided by generation units "for free" as it is an intrinsic physical feature of synchronous generators. It has been named inertia because it is provided by the kinetic energy of their rotating masses represented through physical equations. In this report, we will continue to use the term "inertia" for such RoCoF-based power output even if it is provided through software-based automata that emulate the transformation of kinetic into electric energy or the reverse, depending on the direction of the frequency deviation.

The development of renewable energy (solar and wind) and exchanges between countries means that a growing share of power generation comes from electronic power converters, replacing synchronous generators and therefore reducing the physical inertia of the system. Indeed, electronic inverters usually lack two physical elements to provide inertia services to the system:

- Short term overloading capability: while synchronous generators can be overloaded to several times their nominal steady-state rating for short period of time, electronic power converters do not. Therefore:
  - Either they have been over-dimensioned to provide inertia without impacting their ability to provide energy,
  - Or they will not be able to provide energy up to their nominal capacity because they will need to reserve some capacity in case RoCoF-based power output is needed.
- An energy source that can be mobilised in milliseconds to provide additional power, be it kinetic (rotating mass), electric (capacitors), or chemical (batteries). Indeed, they usually convert DC power to AC power without storing any energy. It should be noted that the

[4] DNV-KEMA on behalf of Eirgrid, "RoCoF An independent analysis on the ability of Generators to ride through Rate of Change of Frequency values up to 2Hz/s", 2013

amount of energy to be stored is low: at most a few seconds at maximum power is needed. Indeed, the delivery of power from the inertia service is finished when the nadir is reached (i.e. after a few seconds), and then fast reserves are available.

Given the lack of overload capacity, the additional generated power will be proportional to the RoCoF only up to a maximum RoCoF level that corresponds to the maximum power generation capacity of the power electronics converter. Even if the RoCoF is larger, the power output will be capped by the limited overload capacity. In addition, if the storage capacity is small, the delivery of power will be limited in time. Anyway, if the frequency drops below the disconnection threshold (47,5 Hz), the system will black out. Combined with the previous point, this limits the amount of needed energy, and thus this issue is less critical compared to the limited overload capacity.

Besides these hardware limitations, the software of inverters can also bring limitations to their ability to provide inertia. Indeed, the automaton that sets the AC current to be injected into the grid has to be programmed to emulate the behaviour of a synchronous machine. Unfortunately, current electronic power converters have been programmed in a way that do not have the same properties as synchronous machines, as they try to inject a constant power into the grid. They behave like weightless bikers that do not provide any additional power in face of a perturbation. This operation mode is called “Grid FoLlowing” or GFL.

New operation modes called “Grid Forming”, or GFM, are being developed by manufacturers. Provided that a sufficient energy source is available and the device’s rating allows it, they can emulate instantaneous RoCoF-based power delivery (inertia). The inverters keep track of the wanted frequency and delivers additional power in case a slow-down is detected. Keeping with the bike analogy, the electric biker is still weightless but keeps in mind the wanted speed (or slowly adjust to the real biker) and monitors the chain speeds. If the chain speed slows down, it can provide instantaneously additional power. It does not need one turn of the wheel to see that the rotation speed is lower.

It should be noted that not all behavioural aspects of a synchronous machine should be implemented:

- A synchronous generator only releases part of its energy through inertia (only the one delivered when the frequency drops from 50 Hz to 47,5 Hz, i.e. more or less 10%). Being software-programmed, electronic power converters can use all their kinetic energy.
- Power converters are not limited to an answer that is proportional to RoCoF. They could have other more desirable behaviour (like having an “emergency inertia service” that would be activated only in case of high RoCoF). However, the power system is complex. Inertia ensures its fundamental stability, and it will be difficult to make it rely on other principles, especially during the transition period.

By mimicking synchronous machines, GFM power converters are also expected to mimic their behaviour following voltage drops or short-circuit, thus solving many other issues related to the phasing out of synchronous generators.

2. Challenges to ensure frequency stability in the future European electricity system

2.1. What is inertia and what needs to be procured?

General definition of inertia

Generally speaking, inertia is the characteristic of a system that dampen instantaneously the effect of a perturbation. A power system is composed of generators, the grid (lines, transformers), and loads. At any time, the power withdrawn by loads is equal to the power injected by generators plus the power provided or withdrawn by the system itself. In case a generator disconnects, continuing to operate in a stable way means continuing to provide the same power to loads. However, there is no instantaneous increase of power inputs in case of such a loss. As the power provided to loads has to remain constant within contractual limits for the system to be considered as stable[5], the additional power has to be provided by the system itself. This capability is called inertia.

To sum up, the inertia is the mechanism that triggers a power adjustment proportional to the Rate of Change of Frequency (RoCoF) in few tens of milliseconds after the occurrence of the power imbalance that triggered the change of frequency (power increase if the frequency drops after a loss of generation, power decrease if the frequency increases after a loss of load). The reaction is independent of any control system, in particular it happens without any frequency measurement. input or output variation, independently of any control system.

Historically, inertia relied on the kinetic energy of synchronous machines (generators, condensers, motors) and on physical laws to deliver this power adjustment. Power-electronics converter-based devices with **G**rid-**F**or**M**ing (GFM) capabilities are also able to emulate this mechanism thanks to an energy source (chemical for batteries, electrical for capacitors, or, potentially, even mechanical for wind farms) and to software-defined automata. Therefore, they will play a crucial role in addressing the challenge of replacing synchronous machines. Unlike traditional **G**rid-**F**o**L**lowing (GFL) inverters), grid-forming inverters mimic the behaviour of synchronous generators.

The amount of inertia of the system could therefore be estimated by the ratio between the additional power output and the Rate of Change of Frequency (in MW.s/Hz) or the slope of the power-RoCoF characteristics diagram:

$$\frac{\Delta P}{|RoCoF|}$$

As the concept of additional power output is not convenient, it is more usually expressed into the amount of kinetic energy that would have to be stored in a large synchronous machine to obtain the wanted behaviour, in GW.s. It should be noted that it is an equivalent kinetic energy and that some technologies like GFM may need to store less energy. It is more convenient because the equivalent kinetic inertia can be derived from the maximum power of the asset providing inertia (or, more usually, of its rating in MVA) through the multiplication by a constant expressed in seconds that depends mainly on the technology.

[5] The first chapter mentioned that the electrical power withdrawn by a load that provides inertia changes during contingency. However, the final power (e.g. the mechanical power provided by a motor) is not impacted by inertia provision, though it is by the following frequency drop.

$$E_{kin} = \frac{\Delta P * f_0}{2 * |RoCoF|}$$

Even more conveniently, the amount of system inertia can be expressed in seconds[6] by dividing the equivalent kinetic energy E_{kin} by the load of the system P_{load}. The typical inertia constant of an electrical system is a few seconds, with the additional energy provided by inertia during an event that does not lead to a black out being around 1/10th of it. It justifies the usual assumption that the power system is "instantaneously balanced", even if we see that it has inertia to face a reasonable loss during a few seconds.

$$H = \frac{E_{kin}}{P_{load}}$$

Usually, inertia is supposed to be symmetrical:

- The additional power is positive if the RoCoF is negative (more power is injected when the frequency is decreasing because the system lacks generation to be balanced)
- The additional power is negative if the RoCoF is positive (less power is injected when the frequency is increasing because there is an excess of generation)

However, as it may be more costly for some technology to react in both direction, inertia can be differentiated into two parts:

- Upward inertia, characterized by the slope of the $\Delta P - RoCoF$ curve when RoCoF is negative.
- Downward inertia, characterized by the slope of the $\Delta P - RoCoF$ curve when RoCoF is positive.

To illustrate these formulas, an example of numerical application to provide an order of magnitude of the maximum generation loss that can be covered by 2 seconds of inertia is given:

- Let's assume the system inertia: H=2 seconds
- And that the maximum admissible RoCoF is: 1 Hz/s
- Then, the equations above can be combined to obtain the percentage of power lost at the maximum admissible RoCoF:
$$\frac{\Delta P}{P_{load}} = \frac{H * 2 * |RoCoF|}{f_0} = \frac{2 * 2 * 1}{50} = 8\%$$
- Let's assume that the time before reaching the nadir (through action of reserve) is 2.5 second. During this time, let's assume that the RoCoF is sustained at 1 Hz/s
- The amount of equivalent kinetic energy delivered can then be computed:
  - Energy to be delivered during the event: $E = 8\% \, P_{load} * 2{,}5 \, second = 0{,}2 \, s * P_{load}$
  - Equivalent kinetic energy of the system: $E_{kin} = P_{load} * H = P_{load} * 2 \, seconds$
  - Which yields $E = 0{,}2 * \frac{E_{kin}}{2} = 10\% \, E_{kin}$
  - Therefore, only 10% of the equivalent kinetic energy was delivered.

For continental Europe, ENTSO-E realised a study to ensure avoidance of blackout after the loss of 10% of the total generation[7]. It is consistent with this simple numerical application that illustrates that inertia, RoCoF, fast reserve activation delay and dimensioning contingency are linked. However, this simplistic application neglects many phenomena:

- Neglected phenomena increasing the needs:
  - Local RoCoF may be higher
  - System splits triggers ΔP way larger than 3 GW as some countries sometimes import several tens of percent of their needs (RoCoF can therefore be higher).
- Neglected phenomena decreasing the needs:

[6] Or in s.MW/MVA to stress that the computation relies (a) on the convention of the equivalent kinetic inertia of the synchronous generators with a total rating expressed in MVA that would provide the service, even if other technologies may store a different amount of inertia and.(b) on the definition of a load of the system in expressed in MW.
[7] ENTSO-E, System Defence Plan, SPD – Inertia TF, 2022 [Link]

- Fast reserves and load shedding can act after 500ms, thus reducing the RoCoF sooner (Nadir may be reached earlier).

RoCoF stability

Maintaining sufficient system inertia is essential to keep the rate of change of frequency (RoCoF) within acceptable limits. The system operation limit is currently set at 1 Hz/s in Continental Europe.

The 1 Hz/s system operation limit in Continental Europe is crucial for maintaining grid stability, ensuring that the power system can respond effectively to disturbances without endangering equipment or causing cascading failures. Exceeding this limit can lead to unintended disconnections of generation or load due to protection relay activations, mechanical stress on synchronous machines, and increased risks of blackouts or uncontrolled islanding. Additionally, excessive frequency deviations can damage generators, cause industrial equipment failures, and disrupt the overall power system, making controlled recovery more difficult.

The system operation limit should be distinguished from the robustness of power generation modules (i.e. their capability to remain connected to the system), specified in the Connection Network Codes as RoCoF withstand capability in range of 2-2.5 Hz/s. The margin between these two values must be sufficient as local phenomena can be more severe than the global RoCoF (up to 2-2.5 Hz/s). ENTSO-E also indicates that although these limits are usually determined in a 500 ms time window, the initial value can be significantly higher than the average value.

Nadir and zenith values

The Nadir in power system stability refers to the lowest point that the system frequency reaches following a disturbance, such as the sudden loss of generation or a large change in demand. A system that allows the Nadir to get very low after an incident increases the risk of regularly triggering under-frequency load shedding (UFLS[8]).

The Zenith in power system stability refers to the highest point that the system frequency reaches following a disturbance, such as a sudden increase in generation or a large drop in demand.

A Nadir or Zenith that exceeds the 47.5-51.5 Hz band can lead to a blackout. While a high zenith can indicate an over-frequency event, it is generally considered less dangerous than a low nadir. This is because an excessively high zenith (frequency exceeding 51.5 Hz) leads to over-frequency disconnections of generation, which, in the case of over-frequency, will reduce the frequency imbalance. It is not the case of under-frequency involuntary disconnections, which will exacerbate the imbalance[9]. Thus, while both high zenith and low nadir can be problematic, a low nadir poses a more immediate risk to system stability and continuity of supply. In most of the report, nadir will therefore often be the only issue cited for simplicity, but zenith should be considered as well.

Two types of measures are necessary

A high RoCoF means that the frequency falls (or increases) rapidly, increasing the likelihood of reaching a dangerously low nadir (respectively high zenith) before reserves or other stabilizing measures can react. In high-inertia systems, RoCoF is naturally limited, allowing more time for frequency control actions like the Frequency Containment Reserves (FCR) to prevent the nadir from

[8] In under-frequency, the following countermeasures are adopted [Link, p.4]:
- Interruptible customers tripping (below 49.8 Hz)
- Hydro storage tripping (below 49.8 Hz)
- Load shedding (below 49 Hz)

[9] Network code conform generation are units that stay connected within the total frequency range of 47.5-51.5 Hz. When the frequency is above 50 Hz, they must reduce their output (at least be stable at reference power). There is also a significant share of non-conform generation, which do not withstand the full frequency band [Link, p.5].

falling too low. However, in low-inertia systems, where RoCoF can be very high, other products are crucial to slow the frequency decline and prevent the nadir from dropping below safe levels.

To recover the loss in system resilience, two elements are essential according to ENTSO-E (cf. 8.2.2).

- Keeping inertia above a certain level to limit to speed and magnitude of frequency excursions ("foundational measure")
- Improving withstands capacities for stable grid operation during high-frequency gradients and frequency containment support to limit the nadir/zenith of the frequency ("enhanced response measures")

Products to be procured

Two types of frequency response therefore need to be secured, at different timeframes:

- **Inertia**, to make sure that the RoCoF does not exceed the level that can be supported by power generators following a contingency. Inertia is instantaneous.
- **Reserves**, to keep the nadir[10] value from getting too low (and/or limiting RoCoF in a second step, without affecting the initial RoCoF during the first hundred milliseconds which is usually the most problematic. Indeed, even the fastest reserves typically cannot react before 500 ms) and to help restore the frequency to its initial level.

Different frequency response products are being used in power systems. In the CE SA, the fastest reserve product being defined and purchased is FCR, a kind of Primary Frequency Response (PFR), but some other power systems use faster reserve products like FFR (Fast Frequency Response).

Fast Frequency Response (FFR) consists of a rapid active power adjustment, either by an increase in generation or a reduction in demand, within a very short timeframe (typically less than 2 seconds) following a disturbance. FFR is designed to stabilize frequency before slower-acting reserves can take over. Given a fixed RoCoF level, increasing the amount of FFR reduces the frequency drop (increases the frequency nadir) by reducing the time during which the frequency decreases, meaning that increasing levels of FFR can reduce the need for inertia whenever inertia is required to limit the frequency drop and not the RoCoF.

The FFR can be completed by another product, sometimes called **Primary Frequency Response** (PFR), which provides a sustained response to stabilize and restore frequency after an initial disturbance. PFR is typically activated within a few seconds and works by adjusting generation or demand in proportion to the frequency deviation (this is called a droop-based response). The FCR (Frequency Containment Reserve) can be considered a PFR product, but there can be other PFR products which act faster than the FCR.

PFR is essential because, while FFR helps arrest the frequency decline, it is PFR that maintains system stability by balancing supply and demand over a longer period. This response therefore brings the system to a new quasi-steady-state frequency that may be lower (or higher) than nominal, but which is stable. It can then be completed with more traditional reserves to return to the system's nominal frequency.

FFR and PFR are examples of possible products that can be used in addition to inertia to secure the frequency stability of the system. Some countries have initiated markets implementing such products, and examples are provided in section 3.3. However, it is out of the scope of the report to propose a segmentation of the reserve products that would minimize the overall procurement costs for the CE SA, e.g. by introducing FFR in CE SA.

[10] Reserves are also needed to keep the zenith value from being too high. However, as it is usually less challenging because it is usually easier to reduce generation than to increase it, we generally mention only nadir given that covering nadir needs usually also covers zenith needs with some exceptions (asymmetrical reserves, ...).

In addition to very fast reserves, preventive measures are essential. Examples are given in section 3.1.

2.2. What determines inertia need

2.2.1. Main determinants of inertia needs

Changes in the electrical system affecting inertia

A key feature of the decarbonisation of the power system is the development of renewable energy sources (RES), which partly replace gas- and coal-fired power generation. Wind and solar are connected to the grid via power electronics. The number of directly connected rotating masses of synchronous generators to the grid, which inherently contribute mechanical inertia, is decreasing. The stability support traditionally granted by these generators (inertia) is however essential and needs to be secured.

Another key aspect of the transition of the European electricity system is the development of exchanges between regions and countries, which enables greater efficiency. As renewable generation if often placed far from load centres, this results in large transits across the transmission system. One of the most critical factors for potential high RoCoF is a too high transit power flow over long distance. Large transits increase the risks of system splits and, in case of such events, can result into larger imbalances, as indicated by ENTSO-E (cf. 8.2.1).

ENTSO-E stresses that achieving the target resilience level shall not limit the electricity market services or renewable integration through curtailments or re-dispatching (cf. 8.2.1). Indeed, since the increase of power exchanges as well as solar and wind generation are among the main reasons for the decrease of inertia, one could consider that a solution would be to limit RES integration or cross-border transfer capacities.

- Currently, there are limits on solar/wind integration in some zones, in particular islands, for example via system non-synchronous penetration limits at any one time (e.g. 75% in Ireland[11], and about 35% in French islands[12]).
- In Italy, during low demand/high renewable infeed periods, there are challenges related to voltage (beyond usual thermal security limits), low inertia and dynamic instability. To tackle these challenges, a minimum amount of dispatchable power plants able to provide system services is defined. This results into a maximum amount of import at the Northern Italian Border, which can be significantly lower than “normal” Net Transfer Capacity (NTC). This limit is computed for each market time unit, considering demand and generation forecasts available in D-2[13].

Definition of the minimum level of inertia

The minimum level of inertia that is necessary to ensure frequency stability (so called critical inertia) is dependent on the system characteristics such as the largest contingency, the level of interconnection, the system protection device sensitivity, the Under-Frequency Load Shedding (UFLS) setpoints, etc. All these features are generally reflected in the grid code that defines acceptable limits for several parameters (including nadir and UFLS setpoints).

Two key approaches can be considered to define the minimum level of inertia:

- Definition based on a contingency ΔP (similarly to FCR for example)
- Definition based on a RoCoF threshold

[11] Eirgrid [Link]
[12] *Programmations Pluriannuelles de l’Energie des zones non interconnectées* [Link]
[13] JAO [Link], TSOs of Italy North Region [Link]

The reference incident for dimensioning the frequency containment reserves (FCR) in continental Europe synchronous area is currently a load imbalance of 3 GW[14]. However, there is no clear definition of the dimensioning event for inertia.

Instead, ENTSO-E uses a definition based on RoCoF. Currently, the RoCoF threshold considered in Continental Europe is set at 1 Hz/s (it is considered that the system should survive if the RoCoF after a contingency remains below this value)[15].

Studies on Europe show that the Continental Europe (CE) synchronous area strongly benefits from its size (as inertia is roughly proportional to the size of the system) and that, even with a higher share of renewable energy and therefore a lower inertia, the imbalances required to obtain RoCoF values above 1 Hz/s would still be far greater than the current reference incident of 3 GW (cf. 8.2.8).

ENTSO-E indicates that high RoCoF situations are not expected in the CE synchronous area in normal interconnected operation, even based on 2040 scenarios (TYNDP 2018 and 2022). The modelling work carried out for this study (cf. section 2.3.2) also concluded that no inertia need is found under normal interconnected operation for a 3 GW contingency, even in 2050 scenarios from TYNDP2024. High RoCoF situations can be expected during system split events with high power imbalances and low system inertia[16].

It should be noted that for smaller systems, such as islands, it could be necessary to study the loss of the largest generator unit to evaluate inertia needs. For example, a study on the link between inertia and ancillary services in Great Britain considered two key factors in its analysis: the loss of a new large nuclear unit, and the large-scale development of wind turbines (cf. 8.2.15).

System splits

The loss of system resilience will expose the electricity system to the risk of being unable to withstand out-of-range events like system splits, that were previously manageable.

A system split occurs when the system is unintentionally separated into two or more asynchronous islands due to disturbances like faults or equipment failures (e.g. on transmission), or protective relay actions. Such events may, for example, be due to human error (the system is particularly complex as it contains millions of assets, with numerous interfaces and stakeholders) or extreme weather conditions (storms, wildfires, droughts, ...). ENTSO-E indicates that, though it should not happen after a single contingency that should have no consequences on the supply, increasing power flows and grid utilisation in future power systems increases the risk of large incidents due to the grid being operated closer to its limits and with increasing amount of power exchanges (cf. 8.2.2).

Since system splits interrupt the power flows between two areas, they induce an imbalance between generation and load in one or more of the resulting areas. Each isolated area must suddenly operate on its own to compensate for the lost exchanges. After the split, the frequency can decrease or increase rapidly (high RoCoF), potentially leading to generation tripping or in the worst case to blackouts.

Therefore, as system splits consequences can be catastrophic, adopting preventive actions is crucial. This includes the implementation of learnings from previous events and grid reinforcement in the face of increasingly large and variable power flows, onshore and offshore, across Europe. ENTSO-E indicates that fundamental requirements to avoid blackouts during unforeseen major disturbances

[14] The historical FCR dimensioning criterion is “deterministic”, as it is meant to handle frequency deviations resulting from the worst-case system outages, typically set at 3000 MW. In 2023, the TSOs proposed a “probabilistic” approach, which aims to dimension FCR in order to reduce the probability of insufficient FCR capacity to events occurring once every 20 years or less. Extreme events such as system splits are however not considered with this probabilistic approach. [Link, ACER] [Link, ENTSO-E]

[15] An equivalent dimensioning contingency can be computed based on this RoCoF value and estimates of available kinetic energy. The “survival” is defined as the fact that at least one subsystem is not blacked out after a split.

[16] ENTSO-E, Frequency stability in long-term scenarios and relevant requirements, 2021 [Link], and discussions with Project Inertia for this study.

include reliable system defence plans (to mitigate the consequences within each island) and a minimum level of inertia (to limit possible RoCoF and the associated decline in resilience). According to ENTSO-E, this minimum level of inertia should not be understood as a limitation to RES but rather an enabler to large RES integration (cf.8.2.1).

An ENTSO-E study (cf. 8.2.2) analyses the system splits that have occurred in Continental Europe since 2003. The reports from these 5 incidents demonstrate that in every case the volume of the power flows at the interface at the time of the split was greater than 3 GW (current dimensioning incident for FCR), even reaching 9.26 GW during the system separation of 2006. A summary of the characteristics of these system splits can be found in section 8.3.

Level of risk to be covered

System splits show very low probability of happening but represent high risks. They are considered out-of-range contingencies as it is not possible to maintain full supply of loads in all split situations. Therefore, activation of defence plans (including load shedding) is allowed after a system split. ENTSO-E thus do not define the maximum load imbalance the system must withstand without deploying defence plans on the interface of a given potential split. System splits are, for example, not considered in the approach discussed for FCR dimensioning using a probabilistic approach (as FCR is not dimensioned for emergency state). They are not either for day-to-day grid security analysis as the loss of any single line should not impact the exchanges.

A key question is the definition of the level of risk to cover or the target resilience level (the capability to survive the split and avoid a potential blackout). This question lies at the heart of the assessment of the need for inertia. The higher the level of resilience targeted, the greater the need for inertia and therefore the greater the cost. ENTSO-E indicates that the accepted level of risk resilience and the accepted risk of blackout should be agreed on by all stakeholders and relevant institutions. Indeed, as consequences are not bound to a single TSO but will affect at least a full synchronous zone, it is not for the transmission system operators (TSOs) alone to define these aspects.

In its last report (cf. 8.2.1), ENTSO-E proposes a roadmap concerning the foundational solution measures for a non-regret step-by-step approach to deliver secure and efficient operation of the future decarbonised European power system. For its assessment of additional kinetic energy needs, ENTSO-E focuses on **Global Severe Splits** (GSS), which are split cases where there is a risk of a blackout of the entire Continental Europe grid. Indeed, in the case of GSS there is no neighbouring grid able to promptly restore a blacked-out subsystem, which exacerbates the consequences of the blackout. ENTSO-E indicates that avoiding a significant number of GSS situations is not a complete solution or definitive metric per se, but – as a minimum – a very important resilience reference to safeguard. The number of cases where GSS are avoided is therefore used as a way to assess system resilience, rather than a design incident to be covered. It should be noted that even if all GSS were avoided, other split situations where one subsystem could experience a blackout would remain.

2.2.2. Key elements for the evaluation of inertia need

RoCoF to be considered

The rate of change of frequency (RoCoF) depends on the system's inertia (E_{kin}) and change in power (ΔP contingency): $RoCoF = \frac{\Delta P * f_0}{2 * E_{kin}}$

The RoCoF values are inversely proportional to the level of inertia in the system.

The RoCoF value of 1 Hz/s is often taken as a limit for safe system operation meaning that in case of an event such as the loss of a unit, the RoCoF should not exceed this value. It is crucial to distinguish this value from the RoCoF withstand capacity required by the grid codes, which define the technical and operational criteria that network-connected equipment must comply with.

For its studies of inertia need for Continental Europe, ENTSO-E considers that absolute values of RoCoF is above 1 Hz/s (over a 500ms time window) are unacceptable. ENTSO-E indicates that initial RoCoF values after a contingency higher than 1 Hz/s can compromise the efficiency and resilience of defence plans actions aiming to stabilise the grid. This is because balancing actions are not fast enough to restore the system active power balance before reaching a frequency threshold at which most of the generation begins to disconnect, which in turn leads to blackout (cf. 8.2.2). In addition, there are limits to frequency and RoCoF measurement (cf. end of this section). Due to the loss of grid control, such RoCoF are not sustainable with some of the present technology, in particular the synchronous machines and auxiliary loads/processes within thermal power plants, according to ENTSO-E (cf. 8.2.3)

The grid codes set specific thresholds that generators and converters must withstand without disconnecting to ensure grid stability. The gap between the 1 Hz/s system operation limit in Continental Europe and the withstand capability thresholds set by grid codes (typically in range of 2-2.5 Hz/s) is necessary to take into account several factors. These include local disparities of RoCoF (RoCoF is not homogenous on the grid, even within a country, and can exceed the system design criteria locally), and the difference between instantaneous RoCoF measurements and rolling average calculations over a defined period (e.g. 500 ms or 1 s, as for shorter periods assets should be able to withstand higher RoCoF due to voltage dips, so-called fault ride-through).

These maximum RoCoF values are not the same in every power system. Grid codes can also be changed. For example, in Ireland EirGrid initiated a trial to raise the system operation limit from 0.5 Hz/s to 1 Hz/s[17], in order to accommodate large share of non-synchronous renewables (up to 75% of instantaneous penetration). This project was started in 2014, and operational trials were still ongoing in 2023: such modification for grid codes is a long-term issue.

These changes in the grid code are a way to reduce the need of inertia (as admissible RoCoF are higher). For the CE synchronous area, moving the admissible RoCoF from 1 Hz/s to 1,5 Hz/s would significantly decrease the level of inertia needed (cf. end of section 2.3.2), if we consider the RoCoF to be the main driver of inertia needs (and not the nadir). However, a higher RoCoF means a faster initial frequency drop, which could bring the system closer to dangerously low nadir or under-frequency load shedding (UFLS) thresholds, meaning the system would still need to ensure that the frequency does not drop below the acceptable minimum. This could be done with fast frequency response (FFR) or other new products. A 2013 study in Ireland[18] concluded that with RoCoF values of 1.5 Hz/s and 2 Hz/s, unstable operation of generators could happen.

In a study (cf. 8.2.3), ENTSO-E indicated that part of the solution for inertia could come from means designed to reduce the nadir (LFSM-O, LFSM-U, load and generation shedding), which have an impact on the averaged RoCoF over a given time window. ENTSO-E however stressed that these can only be implemented in long-term via network codes and find their limit for control from 5-10 ms to 100 ms (a window for which there is no doubt that inertia is the only solution to limit RoCoF) or when there is not enough time to measure frequency and react. The more of this potential can be tapped, the higher is the value of the maximum admissible RoCoF. In more recent ENTSO-E studies, such solutions are not as detailed, probably due to their limits in the first few hundred milliseconds.

Adopting a higher admissible RoCoF system operation limit could be based on the ability of power generators to withstand higher RoCoF. This would reduce the need for inertia and allow the definition

[17] EirGrid and Soni, *Shaping Our Electricity Future Roadmap*, 2023 [Link]
[18] EirGrid, "*An independent analysis on the ability of Generators to ride through Rate of Change of Frequency values up to 2Hz/s*", February 2013

of different services to secure the stability of the grid. A 2018 ENTSO-E study[19] indicates that power generation modules shall stay stable and connected to the grid if the RoCoF stays below:

- 2 Hz/s for an average 500 ms window
- 1.5 Hz/s for an average 1000 ms window
- 1.25 Hz/s for an average 2000 ms window

To modify the current RoCoF of 1 Hz/s in the Continental Europe synchronous area could imply a uniformization of the RoCoF withstand capability in the grid codes, which could take time. Currently, the Network Code leaves to the TSO's the responsibility to specify the RoCoF that a power generating module or a demand unit must be capable of withstanding[19].

With the development of distributed renewable generation, the risk of forming electrical islands in distributed systems increases. To mitigate this risk, a common solution for system operators is to install RoCoF-based Loss of Mains (LOM) relays, also known as anti-islanding protection. These relays are designed to trip when the RoCoF exceeds a predefined threshold. If this threshold is too high, actual islands may go undetected. But if this is too low, it is possible that the tripping of a generator causes important RoCoF variation, which then causes inverter-based generation to trip due to LOM relays. This additional loss of generation may lead to an additional drop of frequency leading to cascading tripping and thus to a black out. The settings of these relays have been historically set for systems with high inertia, where RoCoF is contained. In systems with low inertia, the cascading loss of multiple generators resulting from underfrequency may be the greatest threat posed by poor frequency containment control according to an EPRI study (cf. 8.2.9). Some countries have therefore started to raise these RoCoF thresholds, reducing the likelihood of false trips. In Great Britain, LOM RoCoF thresholds were raised from 0.125 Hz/s to 1 Hz/s for example. It can however prove costly to change the setting of all already installed relays.

Similarly, if the RoCoF after an incident is too high, UFLS could be activated prematurely, disconnecting large loads and potentially exacerbating grid instability rather than stabilizing it.

Geographical repartition of inertia procurement and impact on volume needs

Current inertia targets should aim to prevent the RoCoF from exceeding 1 Hz/s after a system disturbance according to ENTSO-E. Large power imbalances can arise in the event of system splits, which may also trigger cascading generator tripping. These system splits, rather than standard generation outages, define the primary need for inertia.

ENTSO-E recommends evaluating the severity of splits based on the fact that at least one island survives (otherwise, these are considered global severe splits). To ensure that at least one island survives, it is necessary to avoid a RoCoF exceeding 1 Hz/s in at least one isolated area. Therefore, inertia needs cannot be determined at the continental level, but for each island.

To ensure that an island can survive and avoid a blackout, the following is required:

- There must be sufficient inertia in at least one island.
- The power imbalance (resulting from power transfers across corridors blocked by the system separation) is within acceptable limits.
- There is an effective and selective underfrequency load shedding scheme in place.
- Generators are able to reduce their active power output sufficiently quickly to avoid uncontrolled over-frequency disconnection of generators.

[19] ENTSO-E, "*Rate of Change of Frequency (RoCoF) withstand capability*", January 2018

To evaluate inertia needs it is therefore necessary to compute inertia for system splits scenarios. ENTSO-E for example used a simplified graph of the European power systems that connects the different countries and developed an algorithm to search for all possible partitions of the graphs in two parts (cf. 8.2.2). Other studies (e.g. 8.2.1, 8.2.6 or section 2.3.2 of this report) analyse a set of relevant system split scenarios. Based on cross-border exchanges from a power system model, it is possible to compute frequency deviations associated to system splits and quantify the need for additional inertia.

The need obtained depends on the level of risk to be covered, in particular whether each island should survive or not.

Since a system split within a country is also a possibility (e.g. Germany during the System Separation of 2006 or the Turkish system separation of 2015) and since local RoCoF values can be higher than the RoCoF value that the global system would have faced if a similar disequilibrium had occurred without split (e.g. a loss of generation equal to the flow on the split interface), the TSOs of each country must also make sure in real time operation that devices providing inertia or devices with grid forming capabilities are evenly distributed across the system to avoid too high local RoCoF values (cf. 8.2.3). However, the exact extent of the uniformity of the distribution still needs to be assessed. It requires differentiating between the possible splits (e.g. those that already occurred) and the less likely ones (like a split between France and Belgium).

Furthermore, the geographical repartition of devices capable of providing inertia can also help solve other local issues like short circuit level and voltage support (see section 2.2.3).

Monitoring of inertia

The assessment of inertia needs faces several challenges, including the complex monitoring of existing inertia and the difficulty in estimating inertia provided by loads.

The literature review highlighted the uncertainty in the role played by loads in a system's total inertia. Few documents provide a methodology to precisely quantify this inertia provided by loads. Some studies indicate that the inertia contributed by loads is not negligible, and it could account for up to 20% of the total inertia in the system[20,21,22], but the review did not provide enough input estimate a value for Continental Europe Synchronous Area. However, this value would need to be approximated in the future to correctly estimate the need for inertia.

In a recent position paper (cf. 8.2.1), ENTSO-E stresses that system operators need new tools to monitor inertia and take action. ENTSO-E proposes to establish an ex-post assessment of yearly inertia levels in Continental Europe countries to monitor the evolution of the overall resilience level and provide information on the need for additional means. Long-term needs and global resilience levels should be reassessed every two years in the regular TYNDP identification of system needs (IoSN) according to ENTSO-E. In particular, it implies tracking synchronous condenser projects as well as GFM projects in the TYNDP. ENTSO-E also indicates that in future re-assessments, the methodology should reconsider investigates splits to consider relevant regional splits lines instead of national borders only. The need for the development of a common methodology to "measuring" inertia, in particular for operational planning and monitoring, is also pointed out.

Currently, there are two main methods for estimating inertia: summing the kinetic energy of transmission-connected generation (which excludes inertia from loads, and requires rules to define

[20] Y. Bian, H. Wyman-Pain, F. Li, R. Bhakar, S. Mishra, and N. P. Padhy, "Demand Side Contributions for System Inertia in the Gb Power System," IEEE Trans. Power Syst., vol. 33, no. 4, pp. 3521–3530, 2018
[21] Wind Energy Technology Institute (WETI), "Determining the Load Inertia Contribution from Different Power Consumer Groups", Henning Thiesen & Clemens Jauch, April 2020
[22] Kumar Prabhakar, Sachin K. Jain, Prabin Kumar Padhy, July 2022, "Inertia estimation in modern power system: A comprehensive review"

the equivalent kinetic energy provided by GFM converters) or measuring the Rate of Change of Frequency (RoCoF) during significant frequency excursions and calculating inertia based on power events throughout the year.

Since the contribution of loads to the global inertia might not be negligible, summing the inertia constants of transmission-connected generation will provide a lower bound of inertia.

Some other issues appear when trying to measure the RoCoF during frequency excursions. As indicated by an ENTSO-E study[23], frequency is not the same throughout the whole system. During a disturbance, the measurement location in the system plays a role due to the propagation of frequency wave. It is not possible to find a location on which frequency accurately represents the behaviour of the system as a whole. To measure the frequency of the whole system, it is only possible to measure frequency at various locations, and from that perform an approximation using the concept of centre of inertia and calculating the associated "weighted" frequency. Alternatively, it is also conceivable to arbitrarily select a location for frequency measurement, but ENTSO-E indicates it is not possible to form a reliable estimate of inertia for the whole system based on one frequency measurement only.

Challenges related to frequency and RoCoF measurement

Frequency can behave very differently in different parts of the system during power system transients, depending on the operational scenario and the fault location. Simulations of frequency response after a line trip carried out by ENTSO-E[23] compared responses at the system centre of inertia to Midskog (in central Sweden), which was found to be the closest match to the Nordic system centre of inertia. Figure 2-1 below, from that report, shows frequency and RoCoF (dotted lines). There are significant differences for RoCoF, for both response time and amplitude (maximum RoCoF is slightly higher in Midskog, but is attained more than 500 ms after the centre of inertia so that the same inertia located in Midskog instead of at the centre of inertia would provide around two times less power after 250ms). ENTSO-E indicated us that event analysis and transient simulation reflects factors up to five between local and global RoCoF.

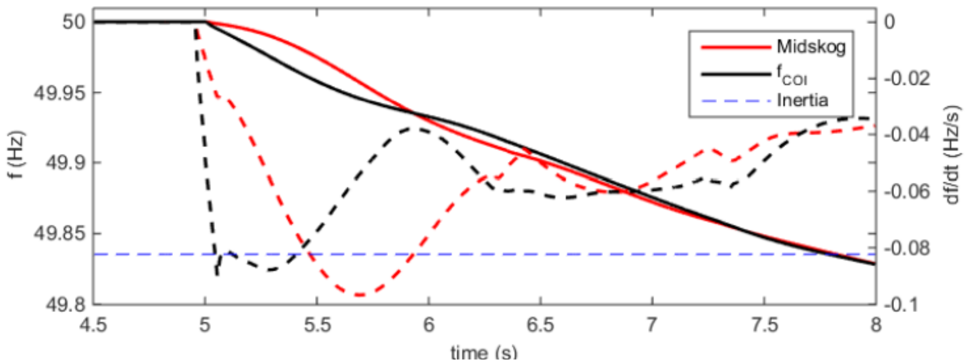


Figure 2-1: Frequency at the centre of inertia and in Midskog (solid lines) and their derivatives (RoCoF, dashed lines) after a trip

Measurement of RoCoF is not instantaneous as it is necessary to measure frequency over several cycles of the sine waves to evaluate changes (cf. Figure 2-2). Required measurement time window for frequency estimation is for example about 120 ms for frequency relays. The total reaction time also includes the circuit breaker opening time on the related voltage level which is in the medium voltage around 70ms. Consequently, the minimum possible reaction time for system protection based on frequency measurement is 210 ms. Even Phasor Measurements Units average measurements are

[23] ENTSO-E, Nordic report *Future system inertia*, 2018 [Link]

over 5 cycles (100 ms). System protection based on RoCoF, which is the first derivative of frequency may require an even longer measurement periods.

Local RoCoF measurements therefore typically take at least 100 ms, but precise and comprehensive RoCoF measurement requires a time window of 500 ms (cf. Figure 2-3).

Application	Meas. Window / ms	Accuracy	Comments
Protection	90-120[3]	30 mHz	generation unit, underfrequency load shedding
Local control	100-200	10 mHz	decentralised generation control
Centralised control	500	1 mHz	centralised generation control (AGC)
LFSM	100	50 mHz	system control, system protection
RoCoF	180-240	50 mHz/s	additional protection criteria for generation or load
RoCoF	500-1000	1 mHz/s	evaluations on synchronous area level

Figure 2-2: Frequency Measurement Requirements (source: ENTSO-E)[24]

On Hydro-Québec system, wind turbines are required to adapt their power output in less than 500ms based on RoCoF (this behaviour is called “virtual inertia”) and batteries in less than 200ms[25]. This does not correspond to “true inertia” as it does not instantly react, without having to wait for frequency estimation, and therefore why inverter-based renewable cannot provide inertia when they are connected with grid-following converters. Overall, this “virtual inertia” is to be classified along with fast reserves, even if it reacts on RoCoF and not on low frequency, because it is not efficient to limit the frequency drop within the 500ms.

ENTSO-E indicates that RoCoF limits (1 Hz/s system operational limit and withstand capabilities of generators) are determined over time windows of 500ms, while measurements can be significantly different on shorter time frames (cf. Figure 2-3).

Figure 2-3: RoCoF filtering (green, mean over 500ms) and un-filtered measurement (brown)

2.2.3. Inertia procurement should consider other local stability issues

Other stability issues exist at the local level

Frequency stability (related to inertia) is not the only stability challenges that the system faces. Frequency stability issues are a direct consequence of power imbalances and sudden strong shifts in

[24] ENTSO-E, Frequency Measurement Requirements and Usage - Final Version 7 - RG-CE System Protection & Dynamics Sub Group, 2018 [Link]

[25] Hydro Québec, Exigences techniques de raccordement de centrales au réseau de transport d’Hydro-Québec, 2022 [Link]

power flows. They are closely linked to voltage stability issues, which have consequences at the local level, and can arise from changing load flow conditions.

The increase of the renewable energy share can cause **voltage fluctuations** due to the variable output. In addition, conventional power plants contribute to the fault current necessary for protective devices to function correctly, the high penetration of renewables thus reduces **short-circuit levels**, affecting protection system coordination.

These issues are out of the scope of this report. However, by tackling frequency stability challenges, a necessary foundation for the system's resilience is established without restricting any solutions that might also be required to tackle other system stability issues.

Solutions to these local issues often also provide inertia

Synchronous condensers are already being used by TSOs for local reasons, providing inertia but also strengthening the transmission systems. It is the case in Denmark where the transmission system started having strength problems as of 2011 due to an increasing wind and solar penetration and the drop of synchronous generators. Synchronous condensers were then installed to provide strength and voltage support for offshore wind farms. They also provide post fault voltage support[26].

Grid-forming converters (GFM)can play a crucial role in stabilizing modern power systems by actively regulating voltage and frequency. They can provide inertia provided that they have an energy source, dynamically adjusting power output to counteract frequency deviations and help stabilize the RoCoF. Additionally, GFM converters create system voltage and contribute to fault level, enhancing short-circuit strength and ensuring proper operation of protection systems. Their ability to regulate voltage and reactive power makes them essential for maintaining stability in weak grids, where low short-circuit capacity can lead to voltage instability and oscillations. Furthermore, in the event of system splits, GFM converters can autonomously sustain frequency and voltage in islanded sections, preventing blackouts and ensuring continued operation in isolated grid areas[27].

Scotland has for example invested in grid-forming converters to support its increasing wind farm energy generation. These systems will solve insufficient Short Circuit Levels (SCL) (the amount of current that flows in the system during a fault) in various locations across Scotland. But they will also provide inertia to help keep the electricity system stable[28].

It is necessary to coordinate the procurement of solutions for all these issues

Since assets that provide inertia can also address other stability challenges, it is essential to coordinate their procurement to ensure efficient supply of inertia. Additionally, these solutions must be strategically distributed to ensure balanced system stability and prevent localized vulnerabilities.

EirGrid, the Irish TSO, considers the geographical distribution of assets providing inertia when choosing the assets participating in its Low Carbon Inertia Services to ensure effective system stability[29]. This approach includes locational incentives to encourage the strategic placement of synchronous condensers and other assets enhancing global grid stability.

The Stability Pathfinder Phase 2 tender[15], conducted by NESO for Scotland, provides a valuable example of how a coordinated procurement of stability solutions can be structured. First, NESO identified substations across Scotland that required support for short circuit level (SCL), inertia, and

[26] CIGRE, "Guide on the Assessment, Specification and Design of Synchronous Condenser for Power System with Predominance of Low or Zero Inertia Generators", technical brochure
[27] ENTSOE, "High Penetration of Power Electronics Interfaced Power Sources and the Potential Contribution of Grid forming", technical report
[28] NESO, "Scotland's wind success story bolstered by £323m stability investment"
[29] EirGrid, "Inertia Management on the Power Systems of Ireland and Northern Ireland", G-PST Future of Inertia Summit, March 2024

voltage stability. To evaluate the effectiveness of each proposed solution, they introduced an SCL effectiveness factor for each substation. This factor adjusted the impact of a solution based on its grid connection point relative to where the support was needed. Voltage levels were also considered, as different voltage levels could reduce the effectiveness at a given substation. Bidders submitted prices per settlement period, based on the CAPEX, OPEX, contract duration, and other financial considerations depending on the proposed technology. NESO then conducted an optimisation process to select the most cost-effective solutions, aiming to maximize SCL at the various locations and inertia support at the lowest possible cost.

2025-04-28 blackout incident in the Iberian Peninsula

While this paragraph, written in early June 2025 is likely to be obsolete in few months, it is worthwhile mentioning the April 28th blackout in this report, both as an example to illustrate the concepts of this section and as a reminder that the blackout provides, at this stage, very little additional information to support the analysis conducted for this report.

The available information is very limited, and experts will need several months to assess the incident. Nevertheless, ENTSO-E has published some news on May 9th with a sequence of events[30] so that some remarks can be made. Overall, our analysis of the sequence of events differs from the scenario studied in this report that is considered to be dimensioning for inertia needs. Therefore, as of now, besides the broad idea that Iberia is an electric peninsula thus with increased blackout risk compared to the core of the CE SA, we cannot conclude on the adequacy of available inertia when the blackout occurred.

- In this report, the scenario is the following: a split occurs following an exceptional contingency between two areas that were exchanging a large amount of power. The contingency is not worsening the resulting imbalance (i.e. the contingency is thought to consist in line trippings but not in generation trippings). Due to the high imbalance that the split triggers because of the interruption of the exchanges, the RoCoF in one or both parts is so high that units disconnect within 500 ms before any defence plan is activated.
- For the April 28th blackout, the initial exchanges between Iberia and the rest of the CE SA were limited (around 3 GW). Disconnection of units in the south of Spain created such a disequilibrium that the exchanges with France increased up to the point that a split was unavoidable. Indeed, the frequency of 48 Hz was reached in Spain at the end of step 1 described by ENTSO-E, which indicates a significant amount of generation tripping before the split. This low frequency triggered the second step: activation of the defence plans. It suggests that the initial RoCoF (during step 1) was limited so that defence plan had the needed time to be activated. There is therefore currently no indication of lack of inertia during step 1. It is possible that RoCoF could have been higher during step 2 described by ENTSO-E due to the high ratio between the imbalance and the available inertia following the equations described in this section. However, neither the scale of the imbalance created at step 1 nor the amount of lost inertia during this step are known so that no conclusion whatsoever can be made on the inertia needs even if it happened that the RoCoF had been high during step 2. The split is only occurring in step 3, while the situation was already very close to the final blackout.

Only the Iberian Peninsula and a small part of France suffered from the blackout. It did not propagate to the remaining CE SA area. This seems in line with our recommendation to follow ENTSO-E proposal to set the level of inertia needs to allow blackout of one side of the split but not both. However, this recommendation is made with respect to the rough estimation of system split probability due to grid issues that do not worsen the imbalances that have been seen historically. Would the probability of blackout triggered by large amounts of disconnection or by other reasons to be identified by the analysis of the event be reevaluated, the acceptability of the same consequences (complete blackout of a part of the CE SA) would likely need to be reevaluated too.

[30] ENTSO-E, "ENTSO-E expert panel initiates the investigation into the causes of Iberian blackout"

Lastly, it is noticeable that the ENTSO-E mentions that HVDC lines remained connected after the AC lines tripped. It suggests a potential refinement of the methodology used to evaluate the inertia needs after a split. Indeed, we made the worse-case assumption -and ENTSO-E too- that HVDC links are lost too when the split occurs, but we see that there may be partial splits in which only AC lines are lost, resulting in a lower imbalance and thus lower RoCoF.

2.3. Evaluation of the need for inertia

2.3.1. Analysis of ENTSO-E Study

Approach to evaluate inertia need and share inertia requirements

The most recent study conducted by ENTSO-E for its "Project Inertia" aims at assessing the inertia need at the Continental Europe (CE) synchronous area (SA) level (cf. 8.2.1).

ENTSO-E's methodology consists of analysing a set of potential system splits to first estimate the minimum level of inertia at the system level needed to mitigate the occurrences of Global Severe Splits (splits where both islands face blackout risks with a RoCoF > 1 Hz/s). The modelling results indeed show that the number of theoretical system split cases where both subsystems exceed a RoCoF of ±1 Hz/s significantly increases from the 2030 to 2040 scenarios.

It is then necessary to allocate the minimum inertia across the different countries, in a way that ensures system inertia is met to avoid these Global Severe Splits. ENTSO-E indicates that the method employed should not lead to an over dimensioned system (resulting in significantly more kinetic energy than we have today in the CE SA). Two approaches for this allocation are presented in the report:

- **A top-down approach**. First, the requirements for system performance criteria are defined for each global severe split case identified (i.e. kinetic energy needed to ensure a RoCoF < 1 Hz/s). Then additional kinetic energy is computed per split area to meet these requirements. This additional inertia is finally distributed among nodes (i.e. countries, the model therefore does not consider more local issues) within each split area using an allocation key. The allocation key could be based on various input parameters such as shares in total generation, inverter-coupled renewables, or FCR.
- **A bottom-up approach**, which is independent of the total kinetic energy needed to ensure a RoCoF < 1 Hz/s for each global severe split case identified but rather defines a minimum inertia constant *Hmin* that each node should provide. Additional kinetic energy needed to meet this *Hmin* requirement is then calculated for each node. Finally, the system performance is calculated for the given allocations for all identified global severe split cases to assess the efficiency of this inertia repartition.

ENTSO-E recommends using the **bottom-up approach**. Key reasons for this choice are that the bottom-up approach is less complex, easier to monitor, more transparent and easily communicable to stakeholders, and that both approaches are as effective in terms of satisfied global severe splits. Indeed, multiple factors have a significant influence on each country objective with the top-down approach, notably the set of splits considered and the fact that each node influences the others, which also strongly depends on the underlying scenarios. For the bottom-up approach, the additional kinetic energy needed only depends on its current conditions and the chosen minimum inertia constant *Hmin*, which would be the same for all nodes and which can be decoupled from the set of splits.

ENTSO-E presents two possibilities for the definition of *Hmin*, a fixed and variable allocation of kinetic energy needed. The idea behind the variable allocation is to improve inertia only in relevant hours. ENTSO-E stresses that *"the best selection of measures (fixed, variable, or combination) to reach the minimum allocated levels of kinetic energy will depend on country-specific aspects, decisions, and dedicated implementation roadmaps involving all stakeholders concerned. Since country internal* *splits are possible, the equal distribution of resources (not only concentrated in one part of a country) is also advisable."*

Fixed allocation means that a fixed additional amount of kinetic energy is specified for each node all the time. This value would be determined based on near-worst-case hours, using percentile hours during which the requirement would need to be fulfilled (e.g. 90% or 50%). This is well-suited for TSO assets such as synchronous condensers (one-time-only procurement and continuously in operation afterwards), and possible long-term inertia markets. This is a simple and secure approach, but rather conservative[31].

Variable allocation means that the additional kinetic energy required per node changes for each operation hour depending on the available kinetic energy levels and current generation mix. It could be determined for all hours, or only hours where global severe splits occur. Volatile kinetic energy requirements like this would require flexible and liquid market procurement methods. This is in theory more efficient (since requirement is not dimensioned according to worst-case hours), but it is more complex as it may require short and/or long-term markets that do not exist yet and might be unable to deliver the required inertia based on forecasts.

Quantitative results

Based on the modelling carried out for their study (cf. left graph of Figure 2-4), ENTSO-E indicates that an *Hmin* of 2 sMW/MVA provides good performance in terms of splits satisfied and cost-benefit aspects. This would allow to satisfy around 98% of global severe splits (meaning that at least one island reaches a RoCoF below 1 Hz/s). The question then concerns whether a variable allocation or a fixed allocation should be used, and at which percentile. Depending on this choice, the modelling show variable level of avoidance of situations where at least one island experiences a RoCoF higher than 1 Hz/s (from ~15% to ~85% at 2 sMW/MVA, cf. right part of Figure 2-4).

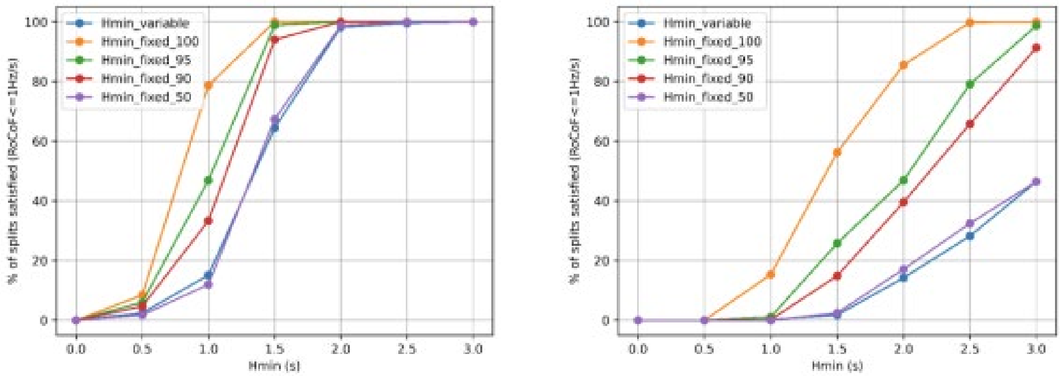


Figure 6: Performance evaluation

Note: The left plot is based on the criterion that RoCoF <= 1 Hz/s is achieved on at least one side of the split (left), which results in the split no longer being considered globally severe. The right plot is based on the criterion that RoCoF <= 1 Hz/s is achieved on both sides of the split (right). 50, 90, 95, and 100 references represent the percentiles where H_{min} is implemented. To exemplify, 'H_{min}_fixed_90' represents the case where the fixed approach ensures that the resulting equivalent H in the node is above H_{min} 90% of the time.

[31] Depending on energy dispatch (spot, balancing), the level of currently available inertia varies throughout the year. A requirement that should be fulfilled 50% of the time means that enough inertia should be added on the system in order to ensure the required level during half the year only. If a uniform amount of inertia is added throughout the year, this requirement would be fulfilled on the 50% "easiest" hours, where there are already significant levels of inertia available so that part of the constantly added inertia is not needed. Conversely, day-to-day procurement of inertia would incentivize actors (historical ones as new ones) to provide inertia only when it is needed, especially during the 50% "hardest" hours. Practically, a combination of securing inertia capacity year-ahead or more and committing inertia resources in day-ahead or closer to real time would result in a less conservative way to ensure a minimum inertia of 2 seconds.

Figure 2-4: Evaluation of splits satisfying RoCoF criteria, depending on the minimum required inertia Hmin (source: ENTSO-E)

The figure above demonstrates that a fixed allocation with an *Hmin* of 2 sMW/MVA 50% of the time provides performances very similar to a variable allocation. Both approaches satisfy almost all the GSS cases but achieve a RoCoF below 1 Hz/s for both sides of the split in barely 15% of the total split considered. In comparison, a fixed allocation with an *Hmin* of 2 sMW/MVA 95% of the time would avoid 45% of such cases.

This 2 sMW/MVA *Hmin* value can be compared with the current annual duration curves of equivalent H for 2019 and the NT2030 scenario (TYNDP2022) for the CE synchronous area (Figure 2-5 and Figure 2-6). The kinetic energy duration curve in 2030 is quite similar to the RGCE 2019 one, but due to the changes in generation mix per production type it can be observed that the global H value for CE stays way below the 2019 level.

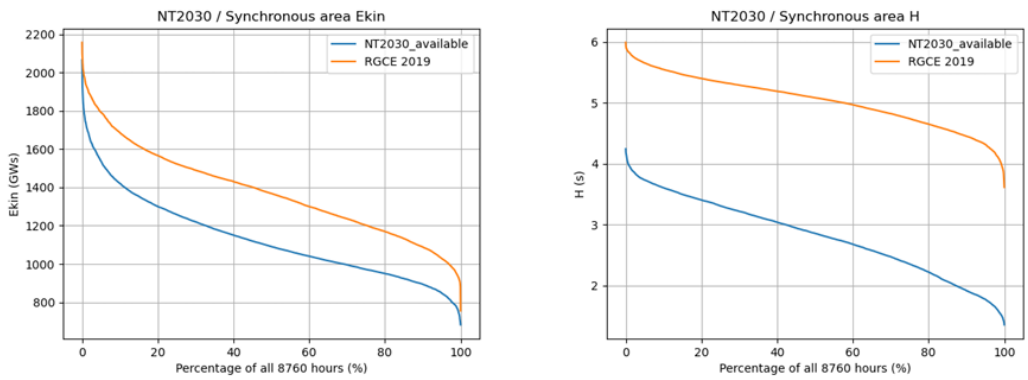


Figure 2-5: Comparison between 2019 and NT2030 (source: ENTSO-E)

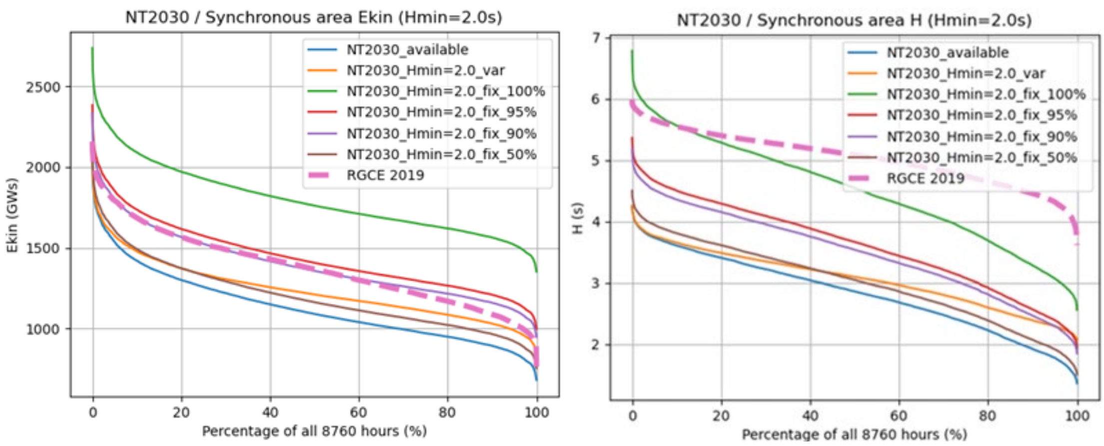


Figure 2-6: Kinetic energy (left) and inertia constant (right) duration duration curves in 2030 for the variable and fixed approaches (2019 provided for reference) (source: ENTSO-E)

In 2019, the equivalent inertia constant for CE SA was above 3.5 s 100% of the time. However, in the NT2030 scenario with reduced levels of inertia in the system the inertia H for CE SA stays above 2 s for only around 85% of the year. The additional kinetic energy needed at the synchronous area level to ensure a 2 sMW/MVA inertia constant in all countries for 50% of the time represents 73 GW.s. To ensure a 2 sMW/MVA inertia constant for each country 90% of the time would require an additional kinetic energy of 267 GW.s across the CE synchronous area.

Recommendations on inertia targets

Since ENTSO-E's priority is given to the avoidance of GSS cases in a first realistic no-regret step, they recommend adopting a requirement consisting in ensuring a minimum inertia constant (*Hmin*) of 2 sMW/MVA 50 % of the time in each country by 2035 (short-/medium-term target). ENTSO-E indicates that, for this first step, part of the targets can be largely ensured with technologically available TSO assets. This first step would already provide a significant increase in resilience levels.

ENTSO-E also advocates that as a subsequent long-term target (subject to reassessment based on the return of experience, efficiency of grid forming, progress on foundational measures, and evolution of assets' RoCoF withstand capability), all countries shall ensure a minimum inertia constant of 2 sMW/MVA for 90 % of the year. This would mitigate the risk that both separated islands experience a RoCoF above 1 Hz/s.

The total kinetic energy at the SA level resulting from both targets still remains below the total kinetic energy levels available in CE in the past (see Figure 2-6).

Discussion on ENTSO-E's recommendations

ENTSO-E focus is on the "survival" of the system, which depends on the RoCoF rather than on fast reserves, and therefore on inertia (fast reserve only allows to decrease defence plan activated load shedding, which is allowed in case of system splits that are considered as exceptional contingencies). ENTSO-E indicated that, as long as the instantaneous RoCoF remains limited, defence plans should be enough to ensure survivability of the system (and it is acceptable to use them as splits are considered out-of-range events).

A first key element for the assessment of inertia needs is the system operation limit of 1 Hz/s RoCoF. As the impact of this limit on needs is very significant, we recommend that further studies are performed to evaluate as precisely as possible the optimal limit, taking into account the risks associated to a higher RoCoF limit, as well as the feasibility and cost to upgrade equipment that would be impacted by a higher RoCoF limit.

Another key element for the evaluation of needs is that ENTSO-E proposes to assess system resilience based on the number of avoided Global Severe Splits (GSS). ENTSO-E indicates that the accepted level of risk resilience and the accepted risk of blackout should be agreed on by all stakeholders and relevant institutions. The proposed system resilience target, which focuses on the survivability of the system but does not eliminate all risks of blackout, seems reasonable to us. Indeed, while system splits are exceptional, they have happened in the past and seem to be likely to happen frequently enough in the future to justify action, in part due to increased exchanges. This justifies costs for inertia procurement of an order of magnitude or lower than those estimated in this study as inertia is needed to avoid that system splits lead to blackouts of the full Continental Europe Synchronous Area which could last several hours.

ENTSO-E advocates for step-by-step no-regrets actions to improve the situation of decreasing inertia. ENTSO-E indicates that currently, adding kinetic energy to the system as a foundational measure helps achieve the target resilience level. ENTSO-E therefore advocates that, as soon as possible, any device that can provide inertia and will be connected to the CE grid – such as Power Park Modules (PPMs), STATCOMs, and SCs connected for system strength/voltage needs – shall be able to provide inertia by using grid forming converters (GFM). We think that considering inertia as a by-product when TSOs procure new assets is important, as it will not always come automatically (a small energy storage of a few seconds is necessary for GFM converters to provide inertia, the flywheel of synchronous condensers could be larger to provide more inertia, …).

ENTSO-E stresses that achieving the minimum resilience target depends on the amount and regional allocation/distribution of additional inertia in CE SA. Indeed, a key specificity of inertia, contrarily to reserves such as FCR, is that it cannot be easily transferred across borders. System inertia can be defined as the sum of all available inertia, which could give the impression that it is fungible. Inertia is however different from FCR (which can be procured in other countries although for FCR each control area should provide at least 30% of the capacity locally). Indeed, inertia should enable at least part of the system to survive a system split[32], where each island is separated and therefore cannot benefit from the inertia of the rest of the system. This, however, do not mean that no inertia at all could be exchanged between countries with well-connected systems (e.g., it could probably be reasonable to consider Spain and Portugal together), but this issue needs to be further studied.

A key recommendation from ENTSO-E analysis is to define a minimum inertia constant Hmin requirement expressed as an equivalent kinetic energy value of 2 sMW/MVA that each country should fulfil at least 50% of the time. While the choice of this initial uniform target is a reasonable first step, further studies and methodology developments would be needed to set per country optimal targets. A balance needs to be struck between defining an initial target to encourage the deployment of inertia capacities in newly installed relevant assets, and the need for further studies to define the target in the most relevant way possible.

ENTSO-E asserts that as system split events cannot be anticipated, the available inertia should always be well distributed throughout the system (although the exact uniformity need has not been defined yet), which is a key feature of ENTSO-E's bottom-up approach (*Hmin* uniform requirement). System splits within a country are also a possibility. While reasonable, these assertions could be refined with further studies, by determining the splits that are likely enough to be considered. This might help to define sets of countries for which it would be interesting to study the potential benefits of exchanging inertia. The solution for inertia procurement requires support and commitment at the synchronous area level, including all countries and regions; otherwise, the overall effort might be weakened, posing a risk to the larger area.

ENTSO-E recommends to let each TSO/country determine the most appropriate mix of solutions to meet its inertia targets based on its specific grid conditions and the markets already in place. For example, we can think that some countries will opt for long-term procurement of a combination of services: not only inertia but also other stability enhancing services (e.g., voltage support, short-circuit level), especially in grids with high renewable penetration. Others may focus on implementing market-based procurement as this approach would allow service providers to stack multiple frequency response products (for instance, batteries that are already providing system services could participate in these new markets). ENTSO-E stresses that it is essential to gain experience about the actual performance and mutual interaction of large-scale grid-forming technologies, and that pilot projects are necessary. As ENTSO-E considers inertia markets would essentially have to be implemented at the control area level because of splits events, there might be a liquidity risk. Extensive grid connection requirements may also be a solution.

ENTSO-E evaluations were based on TYNDP2022 NT2030 and NT2040 scenarios. These scenarios are the less ambitious concerning decarbonisation and renewable development compared to other scenarios (Global Ambition, Distributed Energy) as well as scenarios from the most recent edition of TYNDP (2024). The impact of the solutions proposed by ENTSO-E in this study would therefore show lower resilience levels if assessed on these more ambitious scenarios. Inertia targets proposed in this study should therefore be considered conservatives, which is consistent with ENTSO-E's no-regret approach.

[32] It is important to have in mind that ENTSO-E's assessment uses the number of Global Severe Splits avoided as a main criterion (GSS is not defined as a design incident to be withstood, but an indicator useful for the assessment of system resilience). In some of these situations, one island could experience a blackout. The consequences would however be more limited than a total blackout as a faster re-energisation could be possible under the support from a stable part of the grid.

2.3.2. Complementary quantitative evaluation of inertia needs

Methodology

Various options exist to secure the required amount of inertia. However, their relevance depends on the magnitude of the needs. For instance, if the needs are major, market-driven options could be an appropriate approach, to ensure that the most cost-effective measures are taken to secure inertia. On the contrary, if the needs are minor, the implementation of a market-driven mechanism could be cumbersome compared to the expected benefits.

To support decision-making, this section provides complementary estimates of the order of magnitude of inertia needs in Continental Europe Synchronous Area over the coming decades (up to 2050). This complements the ENTSO-E study presented in the previous section, which assessed inertia needs based on a large set of possible system splits (450 splits occurring along country borders). Such an approach could lead to an overestimation of inertia needs, as some of these splits may be improbable in practice. To refine this analysis, this section focuses on historically observed system splits, which provide a more realistic perspective on inertia needs. For instance, the complete isolation of Belgium is unlikely due to its strong interconnections with France, Germany, and the Netherlands. However, it is important to add that by limiting the analysis to past occurrences, there is a risk of underestimating inertia needs because other potential splits, which have not been historically observed but could occur under evolving system conditions, may occur.

The need for inertia in Continental Europe is evaluated in this section for two kinds of events:

1. The reference incident for Frequency Containment Reserve (FCR) dimensioning, i.e., an imbalance of 3000 MW,
2. System splits, by consistent regions.

Regarding the first kind of event, it is assumed that the European system stays synchronized. Regarding the second kind, an assumption of possible system splits to consider must be made.

The study examines past events to understand inertia requirements during grid disturbances:

- Italian Split (2003-09-28): Italy's disconnection from the Continental European grid.
- Three Islands Split (2006-11-04): Fragmentation of the Continental European grid into three separate islands.
- Balkan Split (2021-01-08): Isolation of the Balkan Peninsula from the rest of Europe.
- Iberian Split (2021-07-24): Disconnection of the Iberian Peninsula from the main CE grid.

It should be noted that none of the historical system splits exactly followed country borders, while it is here assumed that system splits follow bidding zones borders, due to data availability constraints.

The modelling steps to estimate the needs for inertia are:

- Hourly dispatches per country and per type of generation provided by ENTSO-E in the framework of TYNDP 2024 scenarios (National Trends, Distributed Energy and Global Ambition) are used as a basis.
- Using typical inertia constant values for each type of generation and typical load factors (allowing to convert a level of production into a capacity synchronized to the grid), the inertia naturally available (kinetic energy) in each country is computed.
- Hourly exchanges along the split line are derived from TYNDP 2024 scenarios.
- For each considered event, RoCoF values are calculated. If they exceed 1 Hz/s, the required additional inertia needed to limit RoCoF to this threshold is determined. In line with the explanation in Annex, these needs (and the natural levels of inertia) will be expressed in GW.s, rather than in reduced quantities (seconds), in order to facilitate the interpretation of numerical results.

The RoCoF measures the speed at which the electrical grid frequency changes over time, typically expressed in Hz/s. It reflects the balance between power supply and demand, with rapid changes indicating significant imbalances.
The RoCoF is calculated using the following formula:

$$RoCoF = \frac{\Delta P * f}{2 * E_{kin}}$$

Where:

- ΔP is the power loss resulting from the contingency,
- f is the system frequency (50 Hz),
- E_{kin} is the total kinetic energy of the system.

To estimate the total kinetic energy of the system, we considered all technologies capable of providing synchronous inertia. However, pumped-storage hydro (PSH) cannot always provide inertia. Therefore, the base case assumes that PSH does not contribute to system inertia and a sensitivity includes it to obtain a range.

The following scenarios and sensitivities were performed for each split:

- The analysis is based on several forward-looking scenarios from TYNDP 2024:
  - National Trends (NT) 2030: Based on current national energy and climate policies.
  - National Trends (NT) 2040: Envisioning higher renewable penetration and its impact.
  - Global Ambition (GA) 2040 & GA 2050: Centralized, low-carbon transitions aligned with global climate targets.
  - Global Ambition (GA) 2040 with climate year 1995 (2009 was used for all other scenarios)
  - Distributed Energy (DE) 2040: A scenario focused on decentralized, locally driven energy autonomy.
- Key sensitivity studies include:
  - Pumped Storage Hydro (PSH) Contribution: Evaluating conditions where PSH may provide synchronous inertia.
  - Variation in Inertia Constant (H): Comparing base case (H = 3 s) with scenarios assuming H = 4 s.
  - RoCoF Threshold Adjustments: Analysing the effects of increasing the maximum allowable RoCoF from 1 Hz/s to 1.5 Hz/s.

For each analysed system split, every hour of the year was analysed, resulting in a total of 315,360 splits configurations computed.

Evaluation of needs based on National Trends

The additional inertia needs are shown in Table 2-1 and Table 2-2. The need is particularly pronounced in peninsular regions such as Italy and the Iberian Peninsula, where the Rate of Change of Frequency (RoCoF) is projected to exceed 1 Hz/s during more than 75% of the hours in 2030 in the absence of additional inertial reserves, should interconnections with the rest of Europe be abruptly lost. Regions where no additional inertia is needed are omitted. This includes the rest of Europe for the Iberian split, Italian split as well as the Western Europe side for the Three Islands splits and both sides of the Balkan split. For a 3 GW contingency at the European level, no additional inertia is required across all considered horizons and scenarios.

Table 2-1: Evaluation of inertia needs at the 2030 horizon for splits and sides where additional needs are identified

2030	Iberian Split (Iberian side)	Italian Split (Italian side)	3 Islands Splits (North-East side)	3 Islands Splits (South-East side)
Additional inertia needed* [GWs]	97	299	171	19
Probability > 1 Hz/s RoCoF	82%	77%	37%	< 1%
Max split border exchange [GW]	5	13.8	11.1	5.5

****The row labelled "Additional inertia needed" refers to the requirement in additional equivalent kinetic energy (GWs) to keep the Rate of Change of Frequency (RoCoF) below 1 Hz/s for all hours of the year 2030***.

Figure 2-7 below shows the distribution of additional inertia requirements as a function of splits. The analysed splits that do not require additional inertia are not displayed.

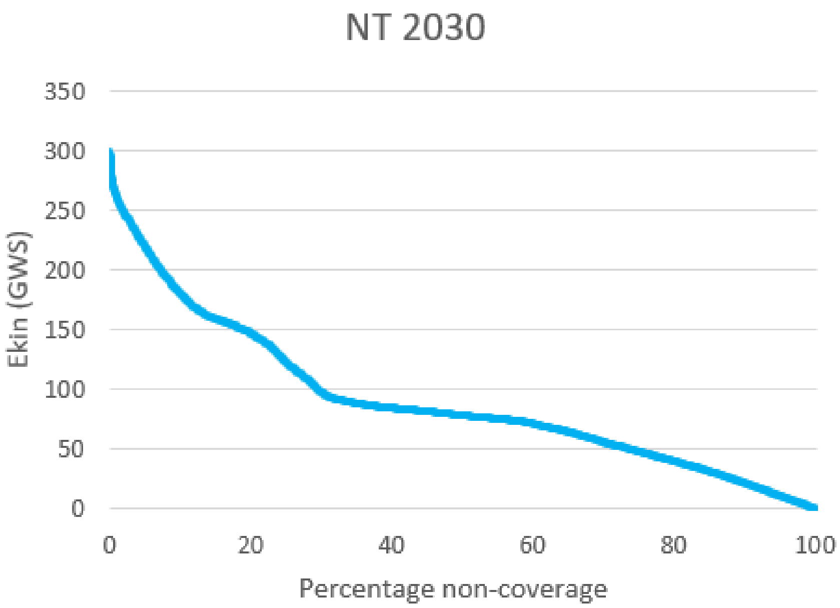


Figure 2-7: Sorted additional needed kinetic energy for all splits requiring additional inertia in the NT 2030 scenario

Table 2-2: Evaluation of need at the 2040 horizon (National Trends) for splits and sides where additional needs are identified

2040	Iberian Split (Iberian side)	Italian Split (Italian side)	3 Islands Splits (North-East side)	3 Islands Splits (South-East side)
Additional inertia needed* [GWs]	142	332	206	17
Probability > 1 Hz/s RoCoF	91%	80%	45%	5%
Max split border exchange [GW]	6.5	15.2	12.3	7.5

By 2040, despite similar cross-border exchange values along splits, the demand for inertia increases by approximately 20% compared to 2030, due to the higher penetration of renewable energy and due to the energy transfer growth along the Iberian Split.

Evaluation of needs based on other TYNDP Scenarios

In the Global Ambition (GA) 2040, Distributed Energy (DE) 2040 and the Global Ambition (GA) 2040 with climate year 1995 Scenarios, the results were closely aligned with the National Trends scenarios.

In the Global Ambition GA 2050 Scenario similar values are observed with an increase in the North-West side for the 3 Islands Split. The reason the values remain similar despite a higher share of renewables in 2050 is that the "additional inertia needed" represents the maximum inertia requirement within a year—that is, during the most critical hour. This peak demand occurs at a time when very little existing inertia is available (due to the high penetration of renewables) and when significant power exchanges occur along the split line. At this moment, the contribution of inertia from existing generation technologies is relatively low, both in 2040 and even more so in 2050, leading to comparable orders of magnitude in inertia needs.

However, if we consider the annual average inertia requirement, the value is considerably higher in 2050 than in 2040. For instance, in Italy, the average requirement increases from 127 GWs in 2040 to 167 GWs in 2050. Furthermore, as indicated in the Table 2-3, the probability that the rate of change of frequency (RoCoF) exceeds 1 Hz/sec is also higher in 2050. Additionally, the West-side in the three-islands split exhibits an inertia requirement in 2050. This additional need is primarily attributable to a reduction in available inertia, notably in Germany. In the South-East region (3 islands split), no additional inertia requirement is observed because the data for Ukraine and Turkey are from 2040 rather than 2050, as this information was not available. This discrepancy likely results in an overestimation of the current available inertia in the region.

Table 2-3: Evaluation of need at the 2050 horizon (Global ambition) for splits and sides where additional needs are identified

GA 2050	Iberian Split (Iberian side)	Italian Split (Italian side)	3 Islands Splits (West side)	3 Islands Splits (North-East side)
Additional inertia needed* [GWs]	125	324	139	248
Probability > 1 Hz/s RoCoF	82%	96%	16%	73%
Max split border exchange [GW]	5	13.2	8.7	10.3

Sensitivities on need evaluation

Pump storage hydro (PSH)

Some pumped-storage hydropower (PSH) plants provide inertia when they use synchronous generators. In these systems, the large rotating masses of the generators store kinetic energy, which helps dampen sudden changes in grid frequency and stabilize the power system.

On the other hand, PSH plants that use converter-based systems decouple the mechanical rotation from the electrical grid. While this design improves operational flexibility and efficiency, it does not allow the plant to provide the natural mechanical inertia that synchronous generators offer.

Under the hypothesis that all pumped storage hydro (PSH) contributes synchronous inertia, the overall system inertia is estimated to increase by approximately 10%. However, due the very high rates of change of frequency (RoCoF), exceeding 7 Hz/s in the Iberian Peninsula and 11 Hz/s in Italy for instance (with or without PSH contribution), this 10% inertia increase has almost no impact on the additional inertia needed.

Table 2-4: Evaluation of PHS contribution sensitivity

PSH sensitivity	Iberian Split (Iberian side)	Italian Split (Italian side)	3 Islands Splits (West side)	3 Islands Splits (North-East side)
Additional inertia needed* with full PSH contribution [GWs]	142	332	206	17
Additional inertia needed* without PSH contribution [GWs]	142	330	205	0

Inertia Constant

In the base case, a conservative assumption (see Figure 2-8) of an inertia constant (H) of 3 seconds was used for all inertia contributing technologies.

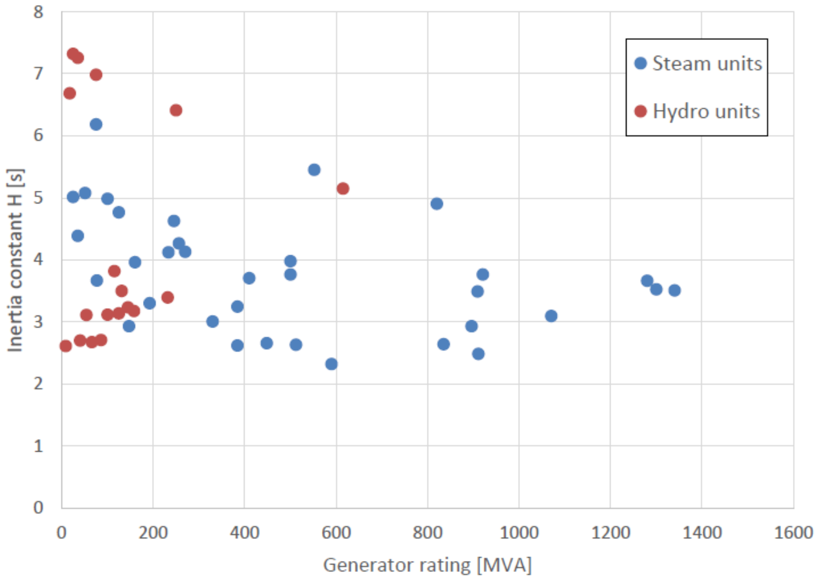


Figure 2-8: Typical inertia constants for conventional units.[33]

Increasing this value to H = 4 seconds enhances overall system inertia and helps lower RoCoF values. However, even with this improvement, regions with high renewable penetration remain vulnerable without additional inertia capacity.

Table 2-4: Evaluation of the Inertia constant sensitivity (NT 2030)

Inertia Constant sensitivity	Iberian Split (Iberian side)	Italian Split (Italian side)	3 Islands Splits (North-East side)	3 Islands Splits (South-East side)
Additional inertia needed* with H = 3s [GWs]	97	299	171	19
Additional inertia needed* with H = 4s [GWs]	87	284	135	0

RoCoF Requirements

The base case assumed a maximum RoCoF requirement of 1 Hz/s. Increasing this limit to 1.5 Hz/s significantly reduces the need for additional inertia. However, this adjustment must be carefully evaluated against its potential impact on protection schemes and sensitive equipment to ensure grid reliability.

Table 2-5: Evaluation of the RoCoF sensitivity

RoCoF sensitivity	Iberian Split (Iberian side)	Italian Split (Italian side)	3 Islands Splits (North-East side)	3 Islands Splits (South-East side)
Additional inertia needed* with RoCoF limit of 1 Hz/s [GWs]	97	299	171	19

[33] Data taken from P. Anderson and A. Fouad, Power system control and stability, Wiley - IEEE press, 2002.

Additional inertia needed* with RoCoF limit of 1.5 Hz/s [GWs]	45	185	80	0

Conclusion

In summary, the precise inertia requirements remain uncertain due to the varying levels of acceptable risk and the imprecision related to existing resources inertia contribution. However, our findings indicate that the inertia challenge is not only a long-term concern but also a medium- and short-term one. Regardless of the scenario or sensitivity factors considered, Continental Europe will likely need an order of several hundred GWs (in additional equivalent kinetic energy) to effectively mitigate the risk associated with system splits.

3. Existing and emerging technologies and approaches to secure inertia

3.1. Overview of technologies and actions to meet inertia needs

Important additional inertia needs are foreseen and represent a challenge in future electricity systems. A proven technology exists to address inertia needs: synchronous condensers (SCs). While synchronous condensers can be quite costly, other technologies also exist which can decrease the cost of procuring inertia. Among these technologies, grid-forming devices appear to be key, as they would allow inverter-based generation to provide inertia-related services. Without them, the large amount of newly deployed grid following inverter-based generation will not be able to provide inertia while they will remain connected for decades.

Grid-forming technologies are however not available at a large-scale as of now, and it might be necessary to revise grid codes to foster their development once they are more standardised. To successfully procure inertia, the revision of the grid codes will necessitate well-defined new requirements for every equipment connected to the grid (not only generators, but also storage facilities, HVDC lines, and potentially, for long term horizons, even loads). A revision could also require the definition of new services that either characterise inertia or bridge the gap between the fastest balancing product currently available in the Continental Europe Synchronous Area (FCR) and inertia, e.g. by developing FFR service procurement mechanisms.

A key challenge is to organise how inertia requirements are met in such a way as to encourage the deployment of the most efficient technical solutions, at the lowest possible cost. It potentially involves organising new markets and, also ensure efficient TSO/DSO coordination.

ERCOT has undertaken an international review of measures implemented to mitigate inertia need and keep it above critical levels (cf. 8.2.13). The table below comes from that study.

Table 3-1: Analysis of mitigation measures implemented (as of 2018, source: ERCOT)

	Ireland	UK	Nordic	Quebec	South Australia	ERCOT
Monitor inertia & possible contingencies in real-time	✓	✓	✓	✓	✓	✓
Forecasts inertia from day ahead to real-time	✓	✓				✓
Dynamic Assessment of Reserves based on inertia conditions and largest resource contingency		✓				✓
Limit Resource Contingency Criteria based on inertia conditions	✓	✓		✓	✓	
Synchronous Condensers (for inertia)	✓	✓			✓ (particularly looking at high inertia SCs)	
Enforce minimum inertia limit	✓	✓			✓ (for minimum inertia req.)	✓

Inertia market/auction/service inertia	✓				✓ (for above minimum inertia levels)	
Faster Responding Reserves	FFR	Enhanced Frequency Response Service		Synthetic inertia from wind	"Contingency" FFR (frequency trigger) and "Emergency" FFR (direct event detection)	Load Resources providing RRS

Other measures related to frequency stability and inertia identified in the literature review include:

- Monitoring inertia and evaluating need on the long-term more precisely
- Modifying RoCoF system operation limit
- Decreasing the size of largest contingency (in systems where it is the main issue for dimensioning inertia needs instead of splits)
- Reducing power plant minimum technical operating capacity[34]
- Shortening the time allowed for frequency response
- Lowering Under Frequency Load Shed (UFLS) setting or raising the frequency response trigger point

3.2. Characterization of technologies capable of providing inertia

Introduction

There are three main types of technologies that can provide inertia: (i) synchronous machines (synchronous inertia), (ii) induction machines (asynchronous inertia), and (iii) inverter-based resources (synthetic inertia or virtual inertia). Note that both synchronous machines and induction machines provide inertia only when they are directly synchronized to the power system (stator directly connected to the grid without inverter(s) between). The following subsections review these three main types of technologies.

Synchronous machines

Synchronous machines (directly synchronized to the grid) were historically the main providers of inertia in power systems, as traditional generators are based on them. In addition to synchronous generators, synchronous condensers (i.e., synchronous machine used neither as a motor or as a generator) have been used in power systems historically to provide dynamic voltage support, bringing as a by-product inertia as well to the system. With the decrease in inertia of power systems all around the world, synchronous condensers start to be used with the provision of inertia as primary purpose. Synchronous condensers can be stand-alone systems, or existing generators can be equipped with a clutch to decouple the synchronous machine from the turbine when it is not used to generate active power. It must be however emphasized that a classical synchronous condenser will only provide a fraction of the kinetic energy of a synchronous generator with the same nominal power, because most of the kinetic energy comes from the turbine for a generator (inertia constant typically between 1 and 2 seconds, although it could reach 4 seconds for specific salient-pole synchronous machines[35]). This is why synchronous condensers with enhanced inertia have been recently developed. For that purpose, a flywheel is connected to the shaft of the synchronous

34 By reducing the technical minimum of synchronous generation, it is possible to keep more running units for the same produced power. As the inertia is depending on the number of running units and not on their generation level, it allows to increase the provided inertia without increasing the share of synchronous generators in the instantaneous mix.
[35] CIGRE JWG A1/C4.66, "Guide on the assessment, specification and design of synchronous condenser for power system with predominance of low or zero inertia generators", 2022.

machine. The inertia constant is then typically around 7-8 seconds but can be as high as 15 seconds[36]. The TRL of classical synchronous condensers is 9, while the TRL of synchronous condensers with flywheels is closer to 8[37]. Regarding clutches, the TRL seems to be around 9, as that technology has been used for decades[38].

Regarding the costs, a distinction must be made between investment costs and operating and maintenance (O&M) costs. For investment costs of classical synchronous condensers, the following figures can be found in the literature: 46.6 k€/MWs[39], approximately 55-110 k€/MWs[40] (assuming an inertia constant between 1 and 2 seconds), and approximately 72.1-144.2 k€/MWs[41] (idem). Associated O&M costs are estimated between approximately 1.93-3.85 k€/MWs/year[42] (idem), equivalent to 26.2-52.4 k€/MWs for a lifetime of 20 years and a discount rate of 4.5%, and 18.6-27.0 k€/MWs (for losses only, depending on the utilization rate of the synchronous condenser). For high inertia synchronous condensers, due to the limited TRL and commercial experience, figures are much more difficult to find. At the moment of writing, the only information available seems to be (i) a capital cost of 25 k€/MWs given in a CIGRE Technical Brochure[43], and (ii) most accepted offers in the framework of the tender "Stability pathfinder phase 1" in Great Britain in 2020 have a price of between 3 and 6 k€/MWs.year[44]. Regarding these last figures, it is not straightforward to deduce a capital cost, as the discount period and rate are unknown (submission of tenders by private companies). In "Stability pathfinder phase 3", the total cost for the contract is computed over 10 years, at 3.5% discount rate. Taking the same assumptions, it would mean a total cost between 23 and 47 k€/MWs. In 2020, GE announced that it will provide two high inertia synchronous condensers to Italian grid operator Terna S.p.A. for the Brindisi (250 MVAr, 1750 MWs, H=7s), but no cost figure appears to be publicly available. In October 2022, AST (the Latvian TSO) signed a contract of 114 M€ for the supply and installation of three synchronous condensers of 100 MVA for a total inertia of 2090 MWs [45,46]. It corresponds to a cost of 54.5 k€/MWs (including installation). Finally, in RTE's (French TSO) report entitled *"Futurs énergétiques 2050",* a capital cost of nearly 0.2 M€ per annum for approximately 100 synchronous condensers of 1.5 GWs is indicated, which would mean a capital cost of 18 k€/MWs for a lifetime of 20 years and a discount rate of 4.5%, and O&M costs around 0.2-0.6 M€/year, equivalent to 18-54 k€/MWs over the lifetime. From the above discussion, a capital cost of 30 k€/MWs seems to be a good reference for a first estimation for high inertia synchronous condensers. For conversion of existing generators (with a clutch), a cost of 60% with respect to new synchronous condensers will be considered[47], i.e., a capital cost of 18 k€/MWs.

As a final comment regarding synchronous condensers, typical lead times are between 2 and 3 years for purpose build synchronous condensers and can vary between half a year and several years for the conversion of existing generators (with a clutch), depending on the technology and the size[48,49].

---

[36] CIGRE JWG A1/C4.66, "Guide on the assessment, specification and design of synchronous condenser for power system with predominance of low or zero inertia generators", 2022
[37] ENTSO-E, "Technology factsheets", 2021
[38] See for example https://www.sssgears.co.uk/en/case-studies/
[39] T. Prevost, G. Denis and C. Coujard, "Future grid stability, a cost comparison of grid-forming and synchronous condenser-based solutions", in Proceedings of the 22nd European Conference on Power Electronics and Applications (EPE'20 ECCE Europe), Sep. 2020.
[40] CIGRE JWG C2/C4.41, "Impact of high penetration of inverter-based generation on system inertia of networks", 2021.
[41] SP Energy Networks, "PHOENIX – Cost benefit analysis of SC and H-SC based on system studies", 2019
[42] CIGRE JWG C2/C4.41, "Impact of high penetration of inverter-based generation on system inertia of networks", 2021.
[43] CIGRE JWG C2/C4.41, "Impact of high penetration of inverter-based generation on system inertia of networks", 2021.
[44] https://www.neso.energy/industry-information/balancing-services/network-services/stability-network-services
[45] https://ast.lv/en/events/three-synchronous-condenser-stations-will-be-built-latvia-synhronise-european-grid
[46] https://www.ast.lv/en/events/month-baltic-states-join-european-energy-system-first-synchronous-condenser-station-latvia
[47] DIgSILENT Pacific, "Repurposing existing generators as synchronous condensers – Report on technical requirements," June 2023.
[48] DIgSILENT Pacific, "Repurposing existing generators as synchronous condensers – Report on technical requirements," June 2023.
[49] AEMO, "Victorian System Strength Requirement – Project Specification Consultation Report," July 2023

Induction machines

Induction machines are used as motors in different sectors (industrial, commercial, service and residential sectors), most of them being synchronized directly to the grid (direct-on-line, as opposed to variable frequency drive motors, decoupled from the grid through power electronics). The kinetic energy stored in the shaft of these motors also contributes to the inertia of the system. However, the coupling between the grid frequency and the angular speed of the shaft for induction machines is loose (compared to synchronous machines), which implies that the kinetic energy will be released with a small delay. The inertial contribution of induction machines is thus called “asynchronous inertia”, to distinguish it from the “synchronous inertia” provided by synchronous machines. It has been shown that the asynchronous inertia has a positive impact on the frequency nadir following a sudden disturbance, but not on the initial value of the RoCoF[50]. Consequently, this technology is not considered further in this report.

Inverter-based resources

There are two main control and operation paradigms for inverter-based resources in AC power system: grid-following (also called grid-feeding), and grid-forming. Both control paradigms can provide inertia, but with different properties. Almost all inverter-based resources (IBR) currently connected to large power systems are based on grid-following inverters. This subsection will thus start by analysing the capability of grid-following IBR to provide inertia. However, as we will see, they suffer from major limitations, which motivates the analysis of grid-forming IBR.

Grid-following inverters behave naturally as controlled current sources: they do not create a voltage reference, and they need thus an already energized grid to provide power. They are nevertheless able to adjust their power output dynamically. They can thus react to frequency transients. For instance, if controlled adequately, they can provide synthetic inertia by injecting or absorbing power in response to frequency deviations. The limitation of synthetic inertia coming from grid-following inverters is the intrinsic delay caused by the need to measure and process the change in frequency. The literature seems inconclusive about the value of that delay and the ability to impact (significantly) the average value of the RoCoF over a 500-ms time window following a disturbance. In 2021, a CIGRE WG stated that the response of grid-following inverters is too slow to contribute to inertia, and that the frequency support should be limited to fast frequency response. Typical delays mentioned in recent works appear to be around 200 ms[51], which is higher than the few tens of milliseconds mentioned in the proposed definition of inertia in Section 2.1. For that reason, and due to the uncertainty on the actual delay (caused also by a limited TRL), grid-following inverters should not be considered as an adequate solution for the time being. Consequently, this technology is not considered further in this report.

On the contrary, grid-forming converters behave naturally as controlled voltage sources: they create a stable voltage and frequency reference. These converters can behave like synchronous machines, because their response time is negligible (<10 ms[52]). For instance, they do not need an already energized grid to provide power. A purely grid-forming inverter able to maintain the frequency (and voltage) at their terminal constant could theoretically provide an infinite amount of inertia (if it had unlimited stored energy and unlimited power capacity) but would not be able to operate in parallel with other grid-forming inverters operated in the same way. To allow parallel operation of grid-forming inverters, several types of controllers have been proposed. The most common one is based on droop control: the output frequency of the voltage waveform generated by the inverter changes linearly with the active power output. By adding a damping term in the equation ruling the output

[50] Lei Chen et al., "Modelling and investigating the impact of asynchronous inertia of induction motor on power system frequency response," International Journal of Electrical Power & Energy Systems, Volume 117, 2020.
[51] V. Baruzzi, et al. “Synthetic inertia estimation in the presence of measurement noise and delays: An application to wind turbine generators,” International Journal of Electrical Power & Energy Systems, Volume 166, 2025.
[52] J. Chen and T. O’Donnell, "Analysis of virtual synchronous generator control and its response based on transfer functions", IET Power Electronics, vol. 12, no. 11, p. 2965-2977, 2019.

frequency of the inverter, a so-called "Virtual Synchronous Machine" (VSM) is obtained. However, both droop control and VSM control are based on phasor quantities, which could limit their ability to respond to fast transient (one or two cycles might be needed). To address fast transient, the Virtual Oscillator Control (VOC) technique has been proposed. In all cases, the provision of inertia with grid-forming converters requires to have a minimum amount of energy stored on the DC side of the converter.

A first possibility to store energy is to use Battery Energy Storage Systems (BESS). The effectiveness of BESS with grid-forming capability has been demonstrated recently in several projects, among which the expansion of Hornsdale Power Reserve in Australia in July 2022[53] and the Blackhillock Battery Energy Storage Project in Scotland commissioned in March 2025[54]. Note however than the response time does not appear to be a few ms, but rather a few tens of ms[55,56]. R&D activities are still ongoing to improve control techniques[57]. For these reasons, we can evaluate the TRL of BESS with grid-forming converters to 8.

The amount of energy needed is however much smaller than what can be stored in a battery (i.e., the ratio energy-to-power should be at least of a few seconds, but not a few hours). It is thus possible to use super-capacitors or ultra-capacitors. A grid-forming converter coupled to a super-/ultra-capacitor is called a e-STATCOM. At the moment of writing, there is no e-STATCOM integrated in large power systems. However, TransnetBW and Hitachi Energy announced in 2024 that TransnetBW has commissioned Hitachi Energy to build two e-STATCOMs in Germany. The construction should start in 2025, and it should be operational by 2028. We can thus evaluate that the TRL of e-STATCOMs is around 7-8.

Converters linked to renewable energy resources could also operate in grid-forming mode under specific conditions. These conditions are different for PV units and wind units. Regarding PV units, they have inherently a negligible amount of energy stored (no rotating mass). Consequently, they are not able to provide naturally a symmetric grid-forming capability, except if they are preventively curtailed or if they are equipped with a dedicated storage mean, such as a battery or a super-/ultra-capacitor. On the contrary, wind turbine units have a rotating kinetic energy stored in their shaft and should thus be able to provide inertia when the power output is sufficient (the turbines' ability to respond being extremely small if the turbines are operating at very low power due to mechanical stress constraints and the necessity to keep the speed above the cut-out speed for an efficient response)[58]. It is however not fully clear from the technical literature if the response time is small enough to meet the proposed definition of inertia in Section 2.1 (i.e., maximum a few tens of milliseconds). Indeed, in its requirement regarding the inertial response of wind generating stations, Hydro Québec mentions that a limit rise time of 1.5 s to reach maximum overproduction[59]. Compliance tests showed response times of a few hundred of milliseconds, but for grid-following converters[60]. The grid-forming capability of wind turbine units might have thus to be enhanced as well by a dedicated storage mean as well, such as ultra-capacitors, to avoid intrinsic limitations due to mechanical constraints. Associated TRLs are estimated to be around 5 for PV systems (mainly studied by simulation and in R&D labs), and around 7 for wind (tests have been conducted for wind turbines in real power systems).

[53] Neoen, "Hornsdale Power Reserve Expansion – Final Project Report", 2024.
[54] https://www.zenobe.com/case-studies/blackhillock-battery-scotland/
[55] Neoen, "Hornsdale Power Reserve Expansion – Virtual machine mode test summary report", 2022.
[56] M. Hishida et al., "Addressing transmission system operability challenges using multi-function large scale grid-forming BESS solutions," Energy Storage Conference 2023 (ESC 2023)
[57] C. Cardozo et al., "Promises and challenges of grid forming: Transmission system operator, manufacturer and academic view points," Electric Power Systems Research, 2024.
[58] A. Roscoe et al., "Practical Experience of Operating a Grid Forming Wind Park and its Response to System Events," in Proceedings of the 18th Wind Integration Workshop, Dublin, Ireland, October 16 - 18, 2019.
[59] Hydro Québec, "Technical Requirements for the Connection of Generating Stations to the Hydro-Québec Transmission System," July 2022.
[60] A. Asmine and C.-É. Langlois, "Wind power plants grid code compliance tests – Hydro-Québec TransÉnergie experience," IET Renewable Power Generation, 2017.

Finally, VSC HVDC converters[61] associated with HVDC interconnectors can also provide inertia. In that case, some energy is stored in the HVDC link itself (capacitive effect) and in the capacitors of the converter's cells[62], but it can be further enhanced also by a super-/ultra-capacitor.

Consequently, there are several practical possibilities to obtain inertia from IBR:

- Upgrade of existing grid-following converters of IBR (RES and BESS) to transform them into grid-forming converters. It would necessitate a control software upgrade and, at least for PV units, the attachment of a super-/ultra-capacitor (as well as probably for wind units to enhance their capability).
- Upgrade of existing VSC HVDC converters to transform them into grid-forming converters with or without the attachment of a super-/ultra-capacitor.
- Use of grid-forming control for new RES, BESS and/or HVDC links.
- Addition of dedicated e-STATCOMs (i.e., grid-forming converters with super-/ultra-capacitors).

In line with a work performed in the framework of the MIGRATE project[63], we propose to consider two main options to quantify costs: (i) the upgrade of converters associated with RES generators, BESS or HVDC links (converter upgrade), and (ii) the addition of dedicated e-STATCOMs (converter addition). That reference gives then the following investment costs for these two options, assuming a time constant for ultra-capacitors of 10 sec (leading to an inertia constant of 5 sec): 19.2 k€/MWs for the converter upgrade option, and 29.2 k€/MWs for the converter addition option. However, these numbers are derived from a bottom-up approach, summing the cost of components. The return of experience related to onshore HVDC stations projects (i.e., for a similar technology) shows that direct costs account for approximately two thirds of the total costs, while indirect costs and site installation accounts for approximately one third[64]. We propose thus to consider a capital cost of 26 k€/MWs for the converter upgrade option, and 39 k€/MWs for the converter addition option. [2]

Summary

As discussed above, various technologies can provide inertia. However, only two main technologies have currently both a high maturity level and a sufficiently fast response time: synchronous machines and grid-forming converters. The table hereafter summarizes the main characteristics of these two technologies. The reader must nevertheless keep in mind that there is a high uncertainty on the actual costs, and that these figures present only the order of magnitude rather than exact values.

Technology	**Synchronous machines**		**Grid-forming converters**	
Category	**Existing generator with clutch retrofit**	**New build synchronous condenser with flywheel**	**Converter upgrade**	**Converter addition (e-STATCOM)**
Estimated TRL	9	8-9	8 (BESS) 7 (wind) 5 (PV)	7-8
Indicative investment cost (k€/MWs)	18	30	26	39

[61] A Voltage Source Converter (VSC) is based on transistors and can have a grid-forming capability. It corresponds to the main HVDC technology used in Europe for now more than a decade. On the contrary, a Current Source Converter (CSC), called also Line-Commutated Converter (LCC) is based on thyristor and does not have a grid-forming capability. It corresponds to the technology used in Europe before the development of the VSC technology (i.e., HVDC interconnectors developed before 2010 are based on the CSC technology).

[62] K. Sano and T. Kato, "Virtual Inertia Control Using Energy Stored in Modular Multilevel Converters of the HVDC Transmission System," *2023 IEEE Energy Conversion Congress and Exposition (ECCE)*, Nashville, TN, USA, 2023, pp. 939-943.

[63] T. Prevost, G. Denis and C. Coujard, "Future grid stability, a cost comparison of grid-forming and synchronous condenser-based solutions", in Proceedings of the 22nd European Conference on Power Electronics and Applications (EPE'20 ECCE Europe), Sep. 2020.

[64] R. Alaei, "Modular Multilevel Converters for Power Transmission Systems," PhD thesis, University of Alberta, 2017.

Associated losses (% of the nominal apparent power)	1.4	1.4	0.15	0.15
Indicative O&M cost (k€/MWs.year)	1.9-3.9	1.9-3.9	0.2-0.4	0.2-0.4
Ownership	Market parties	TSOs or Market parties	Market parties (and TSOs for HVDC links)	TSOs or Market parties

Table 3-2: Summary of the main technologies for the provision of inertia.

3.3. Review of organisational frameworks to cover inertia needs

The existing organizational frameworks highlight the diverse approaches available to ensure power system frequency stability. These approaches can generally be categorized into three main types:

1. Incentives for inertia – Relatively small synchronous systems, such as those in Great Britain and Ireland, compensate units for their ability to provide inertia, ensuring that sufficient inertia is available to slow the RoCoF after disturbances.
2. FFR-like products (Fast Frequency Response) – These services deliver a fixed MW output following a frequency imbalance, regardless of the magnitude of the deviation, and typically activate within hundreds of milliseconds to seconds. They require a frequency measure before activating.
3. PFR-like products (Primary Frequency Response) – In contrary to FFR, their output is proportional to the frequency deviation, meaning they provide a gradual and sustained correction to restore system frequency. FCR is a kind of PFR.

In addition, TSOs may deploy and operate their own assets to cover inertia needs, which are also revised at the end of the section.

Incentives for inertia providers

The table below gives examples of different types of mechanisms that may be implemented for inertia: short-term mechanisms ensuring the optimal allocation of existing assets and mid- to long-term mechanisms whose goal is to steer investments.

Archetype	Short-term	Mid-term	Long-term
Who is managing the product?	EirGrid and Soni (Ireland)	NESO (Great Britain)	EirGrid and Soni (Ireland)
What is the product?	The unit providing **Synchronous Inertial Response (SIR)** contracts for a volume in **MWs²** (a kinetic energy multiplied by the duration of the trading period) During a trading period the unit must provide:	NESO's inertia market is called the **Mid-Term (Y-1) Stability Market**, for delivery across a single year. [65] The unit participating in this market must provide inertia in **GVA.s**. A longer-term stability market (Y-4), providing a four-year delivery window, is	Eirgrid and Soni initiated a **Low Carbon Inertia Services** (LCIS) to procure Synchronous Inertia, Reactive Power support and Short Circuit contribution from non-thermal unit[66] (which represent most units providing SIR).

[65] NESO, NESO awards first contracts under the Mid-Term (Y-1) Stability Market, 2024 [Link]
[66] SEM committee, Low Carbon Inertia Services Phase 1 Procurement Information Note, 2024 [Link]

	SIR Available Volume = Kinetic Energy x (SIRF -15) x the percentage of the trading period where the unit is synchronized to the power system. SIRF is either the kinetic energy (at a frequency of 50 Hz) divided by the lowest sustainable MW output at which the unit can operate while providing reactive power control for the trading period or 45 s (in case of a synchronized providing unit operating as a synchronous compensator or synchronous motor).	also under preparation for 2029. A short-term (D-1) stability market is also envisioned in NESO's 2023 Markets Roadmap. NESO must operate the power system above the minimum target inertia threshold (currently 120GVAs) at all times. The award of these contracts will help contribute to the stability of the GB power system by providing cost-effective, zero-carbon solutions which can be utilised to increase system inertia during periods of shortfall.	The LCIS takes the form of 6-year contracts and aims at financing synchronous assets. The contractual target go-live date for all 6 contracts is set in 2027.
What volume is procured?	In October 2022, the **total contracted volume for Ireland was 688 899 MWs² and 107 366 MWs² for Northern Ireland[67].**	In the inaugural round for the year between October 2025 and September 2026, NESO awarded five contracts to providers delivering a total of **5 GVA.s of inertia**.	In the phase 1 procurement, LCIS successfully contracted **10 963 MVA.s** in total (6 963 MVA.s in Ireland and 4 000 MVA.s in Northern Ireland), which represents approximately **45% of the system's current inertia floor requirement.** The minimum inertia capability contracted is 900 MVA.s and the maximum contracted is 2000 MVA.s at an individual connection point.
At what price?	The total cost of the SIR provision for EirGrid **was 17 445 203 €** for the year 2022/2023[68]. The unit receives a payment for each MWs² of SIR available volume in each trading period where synchronized. **SIR Trading Period Payment = SIR Available Volume × SIR Payment Rate × Trading Period Duration** On the 1st of January 2022, the SIR Payment Rate was **0,0050 €.**	The five contracts had a total cost of **£25.4 million**. According to NESO, the awarded contracts could save consumers £47.3 million over the period (without explaining how this has been estimated. However, in the NESO Pathfinder tender, these saving were estimated by evaluating the avoided generation costs. Indeed, starting out-of-merit order synchronous generation at minimum power just to provide inertia is costly).	All successful bids were procured under the set price caps of **€2.02/MVA.s**, per hour, in Ireland and **£1.79/MVA.s**, per hour, in Northern Ireland. The total combined contract value, covering both jurisdictions, was approximately 29.5% of the total contract value, if the total volume procured had been awarded at the price cap (assuming 6-year contracts and 100% availability)
Which technologies	The only providers of this system service are conventional unit types,	Four of the contracts were awarded to projects overseen by power	The LCIS was designed to support synchronous assets (inverter-based resources

[67] Eirgrid and Soni, DS3 System Services Regulated Arrangements – Gate 7 [Link]
[68] Eirgrid and Soni, DS3 System Services Tariffs Consultation Document, 2024 [Link]

were chosen?	which include Synchronous Compensators. The number of individual Synchronous Compensators is small and the vast majority of SIR is provided by fossil-fuelled generation, hence the procurement of Low Carbon Inertia Services (see below).	generator Drax: two rapid response gas power plants (Millbrook and Progress Power), one gas-fired power station (Hirwaun) and its pumped storage hydro station, the Cruachan Power Station. Also awarded was Deeside Power Station, the turbine rotors provide standalone system support services without generating any electricity (former gas power plant).	were not accepted). 6 synchronous condensers were selected. In the procurement, incentivised zones were defined to take into account reactive power capability and short-circuit contribution. Five out of six of the contracted assets are located within the three incentivised zones, thus fulfilling the procurements locational requirements. The TSOs are currently undergoing studies for Phase 2 of the LCIS procurement to define the system's inertia requirements for 2030 in order to reach the target of 80% share of electricity generation.

Other example of existing mechanisms to secure inertia are;

- In **Germany** the NRA has in 2023 initiated a procedure to define the specifications and technical requirements for the future market-based procurement of inertia.[69] The consultation process has ended on 11 October 2024. The TSOs are expected to launch in 2025 market-based procurement of inertia on the basis of Section 12(h) of the Energy Industry Act (EnWG).[70] This section already included a market-based procurement system for black start capability. The NRA is developing additional procurement rules for voltage control/reactive power and inertial reserve – services for which electricity storage facilities are also well suited.[71]
- In **Australia** the competent authority (AEC) has in 2023 proposed the introduction of a centrally priced and cleared **spot market for inertia**, in which potential providers offer inertia through a bidding procedure. The quantity of inertia required would be set by AEMO on a dynamic basis, in line with the variable needs of the power system. Similar to the spot electricity market, this specific inertia market would be cleared at the bid price of the marginal participant, with all dispatched providers paid the same price. AEC considers this proposal as the best option for a long-term framework for the provision of inertia. In the operational timeframe, a spot market could procure inertia efficiently and dynamically in line with the changing needs of the power system. It also allows to co-optimise dispatch across frequency control services and energy to activate the lowest-cost mix of assets. Over the longer term, AEC considers its proposal would provide consistent and transparent price signals to support efficient entry and exit decisions, as well as to guide investment in innovation in inertia provision.[72]
- In October 2023, the Wholesale Electricity Market (WEM) in **Western Australia** introduced a real-time inertia market called RoCoF Control Service (RCS). The current WEM rules define inertia as "*the kinetic energy (at nominal frequency) that is extracted from the rotating mass*

[69] Bundesnetzagentur - Beschlusskammer6 - BK6-23-010
[70] Non-frequency related ancillary services - Ancillary Services - Energy Market - TransnetBW
[71] Electricity Storage Strategy
[72] Policy_Portrait_Layout

of a machine coupled to the power system to compensate an imbalance in the system frequency", thus reducing it, for the time being, to a market for synchronous inertia. RCS provides a real-time price for inertia that is co-optimised with energy, contingency raise service and the largest contingency size. An interesting implication of this competitive real-time inertia market is that inertia prices could theoretically be zero if enough facilities were already committed for energy and/or other frequency co-optimised essential ancillary services to fully satisfy the inertia requirement.[73]

Products delivering a fixed output regardless of the frequency deviation

Who is managing the product?	EirGrid (Ireland)	Fingrid (Nordics)	ERCOT (Texas)
What is the product?	**FFR (Fast Frequency Response)**[74] There are various FFR products, with units providing dynamic capability and other static capability. Reserve trigger capabilities are not the same (49.8 to 49.985 Hz for dynamic vs 49.3 to 49.8 for static units). The providing units shall provide their expected response within 2s.	**FFR (Fast Frequency Response)**[75] The unit providing FFR must provide a response in **MW which doesn't change with the frequency deviation.** The activation of the Fast Frequency Reserve is **based on automatic local control**. The reserve power must be activated in full within the required time when the frequency falls below a certain value. The power must be activated in full within the required time when the frequency falls below a certain value. The providing unit can select one of these activation options: Activation frequency (Hz) / Max. activation time (s): 49,7 / 1,3 49,6 / 1 49,5 / 0,7	**FFR (Fast Frequency Response)** The product is a **response in MW**. Resources providing FFR must respond autonomously when the frequency drops below 59,85 Hz. The response must be provided in 0,25 seconds after the frequency reached 59,85 Hz.
What volume is procured?	In October 2022, the total volume procured was 1081 MW in Ireland and 369 MW in Northern Ireland.	Fingrid procures FFR from a national hourly market. On the hourly market, bids for the hours of the next day are submitted on the previous evening. Nordics' total FFR procurement on a day varies	The volume procured from the Responsive reserve services (FFR + PFR + Load resources on Under Frequency relays) is typically around 2900 MW (variable hourly need).

[73] WA's Real-time Inertia Market: Design vs Outcomes
[74] Eirgrid, DS3 System Services Protocol – Regulated Arrangements, 2022 [Link]
[75] Fingrid, Fast Frequency Reserve (FFR) [Link]

		between **0-300 MW**[76]. The **daily procurement need is estimated based on an inertia forecast**. The provider participating in the FFR market may submit a combination bid to the Frequency Containment Reserve for Disturbances Upwards market. The maximum capacity of a single bid for FFR is **10 MW**. The minimum capacity of a single bid for Fast Frequency Reserve is **1 MW**.	A minimum of PFR is set at 1400 MW, with a limit of 450 MW on resources providing FFR.[77]
At what price?	The cost of the FFR product for the year 2022/2023 was: **56 171 549 €.**	Fingrid arranges the bids by price (€/MW) and gives priority to the cheapest bid for each day. The required number of bids will be accepted in price order. In 2022 an average is 45€/MW,h.	No cost was found
Which technologies were chosen?	Battery systems (~40%), conventional units (~25%), interconnectors (~15%), demand side units (~10%) and wind turbines (~10%) were selected.	Certified FFR capacity in Finland at the beginning of 2025 include 100 MW of energy storage and 80 MW from consumption (6 MW others)[78]	Energy storage resources (batteries) and controllable load resources mainly.

[76] Fingrid, Reserve products and reserve market places [Link]
[77] Potomac economics, 2023 state of the market report for the ERCOT electricity market, 2024 [Link]
[78] Fingrid, Reserve Market Information on FFR [Link]

Products delivering an output that varies depending on the frequency deviation

Who is managing?	EirGrid (Ireland)	NESO (Great Britain)	ERCOT (Texas)	Hydro Québec
What is the product?	**POR (Primary Operating Reserve)**[79] The unit providing POR must provide an **additional MW Output or MW Reduction** during a frequency event. **The provision depends on the frequency deviation**. The POR period is in the time range of **T+5 to T+15 seconds.**	There are three different products called the Dynamic Services[80]: **Dynamic Containment (DC)** is a post-fault service. DC has a maximum reaction time of 0,5s and a maximum time to full delivery of 1s. It reaches full delivery at +/- 0.5 Hz frequency deviation. Delivery duration is 15min. **Dynamic Moderation (DM)** provides fast acting pre-fault service reaching full delivery at +/- 0,2 Hz frequency deviation. DM has a maximum reaction time of 0,5s and a maximum time to full delivery of 1s. Delivery duration is 30min. **Dynamic Regulation (DR)** is a slower pre-fault service reaching full delivery at a +/- 0,2 Hz frequency deviation. DR has a maximum reaction time of 2s and a maximum time to full delivery of 10s. Delivery duration is 60min. All the responses from these services are proportional to the frequency deviation.	**PFR (Primary Frequency Response)** The response is **droop based** (**proportional to the frequency deviation**).	Wind turbines must provide temporary overproduction (6% of power supplied, for at least 9 seconds), mainly from the energy stored in the rotating masses, in the event of a deviation of the grid frequency, at underfrequency only. The response must start within 0,5 second and reach the maximum production in 1,5 seconds. Another requirement is to limit the reduction of active power during the energy recovery period to approximately 20% of the rated power.[81]
What volume is procured?	In October 2022 the POR volume procured was 1334 MW in Ireland and 664 MW in Northern Ireland.		The volume procured from the Responsive reserve services (FFR + PFR + Load resources on Under Frequency relays) is typically around 2900 MW	Any wind turbine with a capacity of more than 10 MW **must be able to provide synthetic inertia.**

[79] Eirgrid, DS3 System Services Protocol – Regulated Arrangements, 2022 [Link]
[80] NESO, Dynamic Services (DC/DM/DR) [Link]
[81] Hydro Québec, Exigences techniques de raccordement de centrales au réseau de transport d'Hydro-Québec, 2022 [Link]

			(variable hourly need). A minimum of PFR is set at 1400 MW, with a limit of 450 MW on resources providing FFR.[82]	
At what price?	The cost of providing POR was of 46 780 309 € for the year 2022/2023.		No cost found	Required by grid connection codes so no price.
What technologies were chosen?	Conventional units (~35%), battery systems (~30%), wind turbines (~12%), demand side units (~10%) and interconnectors (~10%) were selected.	Mostly Battery Energy Storage Systems.	Batteries can provide PFR, as well as controllable load and some inverter-based resources configured for droop response.	Requirement for wind turbines

The review of existing markets reveals that several fast-response products can be implemented to enhance frequency stability, providing a quicker reaction than traditional reserves like Frequency Containment Reserve (FCR). These products, such as Fast Frequency Response (FFR) and fast drop-based mechanisms, can activate within hundreds of milliseconds to seconds, helping to contain frequency deviations more effectively and limit load shedding, although it does not provide inertia to limit RoCoF. Additionally, market design offers significant flexibility, allowing for variations in pricing mechanisms, activation triggers, prequalification criteria, and settlement structures. Some markets adopt capacity-based payments for availability, while others compensate based on actual response.

TSO-owned assets for providing inertia

Several TSOs in the EU have already invested in synchronous condensers, which are primarily used for ancillary services such as reactive power control but can also provide inertia. For example, following the German government's decision for a nuclear phase-out, one of the generating units at the 2.5 GW Biblis nuclear power plant was converted into a synchronous condenser to compensate for lost inertia and to control reactive power.[83] More recently, in 2024, Amprion commissioned a synchronous condenser in Hoheneck. This machine was also equipped with flywheels to enhance system inertia, in addition to providing reactive power support.[84] Furthermore, a tender by the German TSO for reactive power was awarded to a brown coal generator from the Weisweiler F lignite plant, which was selected for evaluation to assess its feasibility for conversion into a synchronous condenser.[85] In these cases, the national regulator was required to approve and co-sign all contracts with the suppliers., and the costs of these synchronous condensers were covered through the regular German grid tariffs.

Synchronous condensers equipped with flywheels are also installed to provide additional inertia alongside ancillary services. The Italian TSO Terna has for instance installed in its Brindisi substation two synchronous condensers and flywheel units that provide 500 MVAr of reactive power and 3500 MWs of inertia.[86] Additionally, Terna has concluded the tender for five more synchronous condensers with flywheels, each rated at 250 MVAr[87]. Similarly, Estonia, Lithuania, and Latvia have

[82] Potomac economics, 2023 state of the market report for the ERCOT electricity market, 2024 [Link]
[83] Amprion Innovation Report – Amprion
[84] Amprion Press Release – Amprion
[85] Systemstabilitätsbericht – Bundesnetzagentur
[86] GE's synchronous condensers help Terna stabilize the Italian grid - Gas To Power Journal
[87] Ansaldo Energia develops the grid with 5 new synchronous condensers. Ansaldo Energia – Ansaldo energia

each installed three synchronous condensers, featuring a reactive power capacity of 100 MVAr and an inertia of 2,090 MWs, to ensure adequate inertia in preparation for their synchronization with the Continental Europe Synchronous Area. [88,89,90]

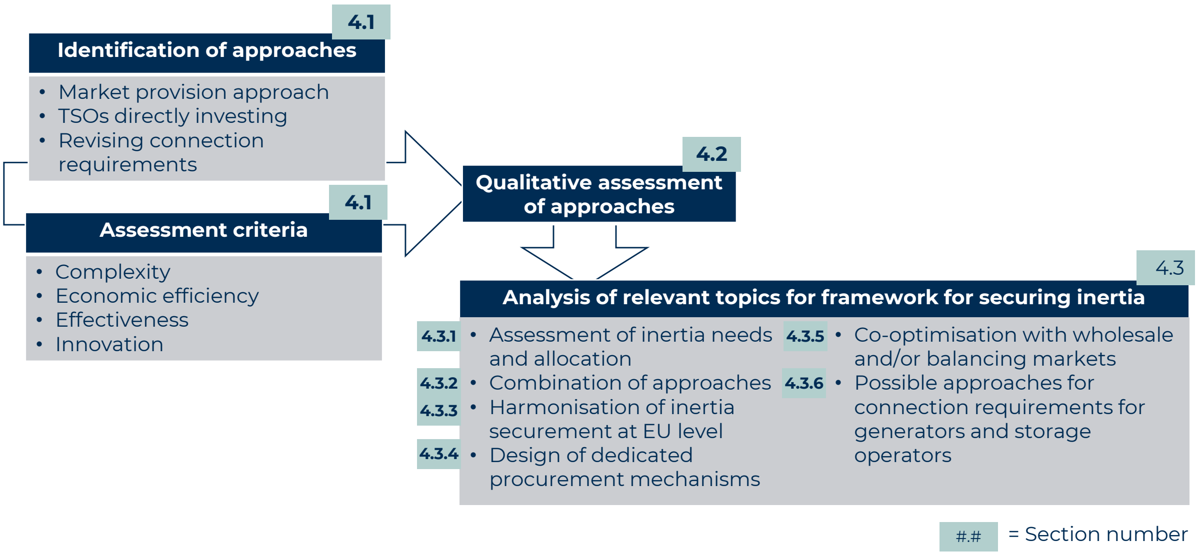
Apart from synchronous condensers, the first contracts for E-STATCOMs have been awarded in Germany, with the system set to be commissioned at the Malchow substation near Berlin in 2028.[91] This E-STATCOM technology will be capable of absorbing 150 MW in 1.25 seconds. Via the use of supercapacitors in combination with normal STATCOM technology It will both stabilize voltage and provide an inertial response.

[88] Augstsprieguma tīkls (AST). "First Synchronous Condenser for Stability in Latvia's Electric Power System Has Been Installed."
[89] Elering. "Elering Has Completed Third Synchronous Condenser."
[90] Litgrid. "Third Synchronous Condenser Arrived in Lithuania; Installation Work Begins."
[91] Grid Stability: Nidec Conversion and 50Hertz lead with Second-Generation STATCOM project near Berlin - Nidec

4. Assessment of options to secure inertia

This chapter identifies and qualitatively assesses three options to secure future inertia needs, building on the assessment of the current and future frequency stability challenges and related inertia needs in the European electricity system, and the overview of present and emerging technologies and approaches discussed in the previous chapters. The approach and different sections in this chapter are presented in the figure below.

Figure 4-1 Overview approach and sections of chapter 4



4.1. Identification of policy options to secure inertia and assessment criteria

Based on the Terms of Reference and taking into account the results of our literature review and further analysis presented in the previous chapters, the following policy options to secure inertia are identified:

- **Market-based procurement through a dedicated mechanism**, which involves establishing a framework where system operators procure inertia services from market parties, either through long-term contracts or real-time markets. Several countries have implemented or are developing such mechanisms, with examples detailed in section 3.3.[92]
- **TSOs/DSOs investment and operation:** In this approach grid operators directly own and operate inertia-providing assets. Unlike market-based procurement, TSO-owned assets rely on long-term infrastructure investments that must be justified through regulatory approval and remunerated through cost-recovery mechanisms such as grid tariffs. Examples of TSO-ownership of inertia-providing assets are presented in section 3.3.
- **Revising technical connection requirements for generators and storage operators**: this involves the update of network connection requirements, shifting responsibility to specific

[92] For example: Ireland & UK: EirGrid introduced Low Carbon Inertia Services (LCIS), awarding contracts for synchronous condensers to replace conventional generators. The UK has implemented similar auctions for inertia provision. Germany: The national regulator (NRA) is finalizing rules for market-based procurement of inertia, expected to launch in 2025. Australia: The Australian Energy Council (AEC) has proposed a centrally cleared spot market for inertia, where providers bid dynamically, co-optimized with energy and frequency control services. Western Australia (WEM): Introduced a real-time inertia market (RoCoF Control Service – RCS), where inertia is priced dynamically alongside energy and ancillary services.

grid users, requiring them to ensure the technical capability to provide inertia services and even to contribute to grid stability on a mandatory basis. Several jurisdictions have already strengthened grid codes to include minimum inertia contributions or dynamic frequency support capabilities for new renewable and storage installations.

There are many considerations regarding the design and actual implementation of the three options detailed above. Each approach has its own implications for cost, regulatory oversight, and effectiveness in ensuring system stability. Moreover, the options above are not mutually exclusive, and their combination may provide a more robust solution. The specific details in implementing these options as well as their potential interactions and synergies are detailed in section 4.3 below.

Another aspect of the analysis entails determining the optimal sequence of implementation. Currently, inertia relies largely on TSO-owned assets, such as synchronous condensers, as well as remaining synchronous generators active in wholesale markets, to ensure baseline system provision stability. Additional inertia-providing assets can be introduced where needed through market mechanisms, allowing for competition and cost optimization. Over time, technical connection requirements can be adjusted to ensure that new grid-connected assets contribute to system inertia, further reducing the long-term need for dedicated procurement. The interaction between the different policy options and possible sequence/timeline for implementation is discussed in the analysis below, particularly in sections 4.3.2 and 4.3.7.

The analysis in this chapter considers the following criteria to assess the selected approaches for securing inertia:

- **Complexity**, which considers factors like coordination challenges between authorities, network operators, market participants and equipment manufacturers. It also evaluates the need for regional coordination, the technical feasibility of using existing instruments and platforms, whether the approach is applicable to existing or only new assets, and the interactions with related services to be secured (voltage support, FCR or faster balancing reserves, and others).
- **Economic efficiency**, which includes overall costs, the promotion of competition in providing inertia (considering also the provision of related FFR or non-frequency ancillary services), incentives for network users to contribute to system inertia, and the extent to which system costs related to inertia provision/procurement can be assigned to network users that cause inertia needs.
- **Effectiveness**, focusing on the ability to meet inertia needs, maintain stability during system separation, ensure adequate inertia distribution across control areas and handle the loss of critical system elements.
- **Innovation**, which looks at how the approach incentivizes the development of new technical and policy solutions for securing inertia.

4.2. Assessment of options to secure inertia

Table 4-1 outlines a summary of the advantages (+) and disadvantages (-) of the following selected options based on the criteria for assessing approaches to secure system inertia:

1. Market-based dedicated procurement mechanism
2. TSOs directly investing in and operating dedicated assets
3. Revising connection requirements for generators and storage operators.

This summary table presents the assessment of the different options, detailing how each options presents advantages and disadvantages under each criterion. Please note that this is the summary table. The full assessment table, which discusses all considerations in more detail, can be found in the first Annex, in Table 6-1.

Table 4-1 Summary assessment table of inertia securement approaches vs criteria

	Impact	3rd-party owned approach	TSO owned assets	Revising connection requirements
Complexity	+	+ Allows for variety of procurement strategies, which can be tailored to long- and short-term inertia needs	+ Centralized control, clear responsibility and oversight + Less uncertainty and need for coordination between stakeholders + Allows for integration in NDP process	+ Allows for standardized approach across various network user categories
	−	- Requires significant coordination and well-defined inertia products, which may not justify small volumes in market - Higher transaction costs - Complexity of procurement with other AS / enabling cross-border inertia services	- Coordination and cost allocation between TSOs	- May pose challenges across areas due to varying grid conditions, infrastructure and regulatory environments - Regulatory burden for enforcing compliance - Can deter investments depending on requirements
Technical adequacy	+	+ Tailored to the system's technical needs + Could allow for regional exchanges	+ TSO can strategically deploy assets	+ Overall improved grid stability + Can simultaneously address other technical needs
	−	- Higher uncertainty to meet all inertia needs and regarding costs - Some market-owned assets better equipped to provide downward inertia services	- Limits the diversity of technical solutions available	- Risk of technical overspecification, imposing unnecessary burdens - Uncertainty in inertia provision in practice
Economic efficiency	+	+ Promotes cost-efficiency by leveraging competitive processes + Can allow for cross-border participation + Simultaneous procurement of other ancillary services possible + Enables price discovery for inertia services + Allows use of existing 3rd-party owned assets	+ Allows for highly tailored investments + Predictable and plannable costs + Allows for TSO-owned asset value stacking for own system needs	+ Creates new incentives to invest in technologies that enhance grid stability + Inertia capability becomes inherent feature of network assets
	−	- Providers may prioritize short-term gains over long-term stability, potentially leading to underinvestment - If not well designed, risk for oligopolistic market	- Substantial upfront investments increase TSO financing needs - Does not allow to leverage market-owned assets, nor can TSO assets be employed for market purposes - Reduced visibility on inertia costs	- If not well designed and/or fails to account for regional differences, this could lead to inefficiencies - If requirements only apply to new users, this leads to limited/slow effectiveness
Innovation	+	+ Market encourages participants to innovate	+ Allow for TSO-led pilot project innovation	+ Can push solution providers on new technologies
	−	- May limit incentives for long-term innovation	- Less pressure for market to innovate - Hampers adoption of innovative solutions	- May limit unconventional or novel solutions. - Drive for innovation may increase costs

4.3. Analysis of relevant topics for a framework for securing inertia

4.3.1. Assessment of inertia needs and allocation across nodes

A critical step before securing sufficient inertia is assessing system-wide inertia needs and allocating them appropriately across different nodes, e.g. respective TSO systems. This allocation must ensure an appropriate distribution of kinetic energy among nodes while avoiding setting excessive inertia needs beyond what would be necessary to satisfy reasonable reliability standards. Allocation strategies should be designed to mitigate the risk of blackouts in the case of system splits, without resulting in an oversized system that introduces inefficiencies. Moreover, ENTSO-E, in their Project Inertia study, highlights that TSOs may need to further allocate inertia requirements within their own systems, ensuring local adequacy in different parts of their networks.

ENTSO-E has identified two primary methods for allocating inertia needs: the bottom-up and top-down approaches (as described earlier on in section 2.2.3):

- The **bottom-up approach** is based on setting a minimum inertia constant (Hmin) for all nodes in the system. This method is preferred by ENTSO-E for its transparency, ease of monitoring, and clear communication with stakeholders.
- The **top-down approach** follows a different methodology. It starts with defining the total Ekin needed to maintain RoCoF ≤ 1 Hz/s for each identified GSS case, calculating additional inertia needs for each split area, and distributing inertia requirements among the relevant nodes using an allocation key, which determines the share of additional kinetic energy each node must provide. As ENTSO-E notes, the top-down approach depends on a number of assumptions, including the system splits considered (which will affect the minimum inertia levels in each node) and cross-border flows.

The cost-effectiveness of these two approaches is further influenced based on how the necessary kinetic energy levels are determined and how they are allocated across time. This can be done using the fixed or the variable allocation method:

- **Fixed allocation method**: A predefined amount of kinetic energy is specified for each node, ensuring a constant provision of inertia at all operational times. This amount is determined based on worst-case or near-worst-case scenarios. The fixed allocation approach is well-suited for TSO-owned assets such as synchronous condensers, which are continuously in operation after procurement. It could also be applied in long-term inertia markets. The advantage of this method is its simplicity and security, ensuring reliable inertia provision. However, it is conservative and may lead to over-provision of inertia.

- **Variable allocation method**: The amount of additional kinetic energy required at each node changes dynamically based on available kinetic energy levels and the current generation mix. Inertia requirements are adjusted hourly, reflecting fluctuations in available kinetic energy. This method is theoretically more efficient, as it avoids unnecessary inertia provision when system conditions naturally provide sufficient kinetic energy. However, it introduces significant complexity, requiring highly flexible and liquid market procurement methods, advanced forecasting capabilities, and continuous monitoring of actual available inertia resources. Additionally, since market-based inertia procurement mechanisms do not yet exist in many regions, implementation could face significant challenges. The variable allocation method should ensure a sufficient level of reliability, if it ensures sufficient inertia in each control area for every moment. Since the amounts are identified for each hour separately, the inertia need requirements can potentially become quite volatile. Therefore, this method requires highly flexible and liquid market procurement methods. Hence, responsiveness of inertia assets is needed, and the method could entail a higher reliance on market-owned assets to make up the inertia gap, as TSO-owned assets would likely provide the inertia at all times, and thus be equivalent to a fixed provision of inertia.

In addition to whether the fixed or the variable allocation method is used, the cost effectiveness of the bottom up approach is also largely influenced by whether inertia needs are defined only for GSS-critical hours or for all hours of operation:

- If inertia requirements are **calculated only for GSS-critical hours** (meaning that the required kinetic energy levels are determined according to system stability needs during GSS scenario hours only), then kinetic energy needs are determined based on expected system stress conditions. This means that inertia provision is optimized to cover only high-risk periods, limiting unnecessary over-provision.

- If inertia requirements are **defined for all hours**, the allocation is independent of specific GSS cases and is instead based on broader system planning data, such as the ten-year network development plan (TYNDP). This ensures a more consistent provision of inertia but may lead to inefficiencies by requiring higher inertia levels than strictly necessary in non-GSS hours.

So, if the bottom up approach is used for determining inertia needs, the cost effectiveness is dependent on two strategy choices (fixed allocation or variable allocation and defined only for GGS-hours or all hours). Therefore, there are four possible implementation strategies for the bottom-up approach. These are the following:

- **Fixed allocation for GSS-critical hours**: Inertia is secured through TSO-owned assets or long-term market procurement but only for specific high-risk periods. This approach ensures stability while limiting unnecessary expenditures in non-GSS hours.
- **Variable allocation for GSS-critical hours**: Inertia is procured dynamically during GSS hours based on real-time forecasts. Future market mechanisms would need to supply volatile amounts of kinetic energy for relatively short periods, requiring highly responsive procurement processes. This implementation strategy would in theory require the lowest inertia resources, as these would be needed to make up for the inertia gap only to the each amount needed in each hour, and only for the GSS-critical hours.
- **Fixed allocation for all hours**: A stable baseline of kinetic energy is secured through TSO-owned assets or long-term market contracts, ensuring continuous inertia availability. This approach guarantees reliability but may lead to over-procurement in hours where natural system inertia is already sufficient.
- **Variable allocation for all hours**: Inertia provision is adjusted continuously, with procurement mechanisms responding to real-time system conditions.

Likewise, for the top-down approach the choice between the fixed vs variable allocation method will also affect the costs for securing inertia. Furthermore, the top down approach may necessitate cross-border allocation of inertia securement costs, depending on how inertia requirements is distributed across nodes. In some cases, it may be more economical to meet inertia needs in one country rather than another, particularly if certain areas have access to lower-cost inertia resources. There's also a mutual dependence in synchronous areas. In interconnected grids, especially within large synchronous areas like Continental Europe, disturbances in one region can propagate and affect neighbouring countries. Therefore, the inertia secured in one control area provides stability not only for that area but also for neighbouring regions, which could warrant cross-border cost-sharing.

The decision on which inertia needs calculation and allocation strategy to pursue should ultimately depend on a **cost-benefit analysis** weighing transparency, operational simplicity, cost efficiency, and market readiness. This analysis would provide key insights into the financial implications of all allocation strategies, guiding decision-making on inertia allocation in a way that balances system security, economic efficiency, and practical feasibility. Currently, there is no detailed cost-benefit analysis available comparting the top-down vs bottom-up methods and their variants.

Beyond determining the most cost-effective allocation strategy, a cost-benefit analysis needs to consider the **absolute magnitude of inertia costs**. The total cost of securing inertia—whether through market-based procurement, TSO-owned assets, or a combination of both - should be compared against the costs of the top-down approach, which is more complex and thus will have higher administrative costs. If the costs of securing inertia are relatively low, e.g. in comparison to overall balancing market costs incurred by TSOs, then the potential cost saving benefits of the top-down approach will be limited. In such a case, operational simplicity may take precedence over theoretical cost efficiencies. However, if inertia-related costs are significant, a well-optimized allocation strategy at the EU level could contribute to ensure cost-effectiveness and avoid excessive burdens on the TSOs and network users.

4.3.2. Combination and prioritisation of TSO vs market party-owned assets

The choice between and combination of TSO-owned assets and market-based procurement of inertia services presents trade-offs in terms of complexity, economic efficiency, technical adequacy, and innovation. As outlined in section 4.2, TSO ownership provides direct control, clear accountability, and easier integration into network development planning, but comes with financial burdens to TSOs, potential economic inefficiencies - as TSO ownership does not allow to leverage market-owned assets, might lead to over-dimensioning of inertia needs at the regional/EU level as cross-border sharing of inertial resources can be more difficult, and provides inertia at all times, even when market assets dispatched in spot and balancing markets might already provide sufficient inertia. On the other hand, market-based approaches can foster competition, cost-efficiency, and technological advancements but introduce complexity, higher transaction costs, and uncertainties regarding long-term stability and adequacy, as there is a risk that the market may not meet the appropriate level of inertia needed.

Given these trade-offs between TSO-ownership and market-owned assets, a combination of both could provide a more effective and balanced solution by making use of all available asset categories in a cost-optimal way. A technology-neutral approach is supported by ENTSO-E for example.[93]

However, while the principle of technology-neutrality should be pursued in securing sufficient inertia, as highlighted in section 3.2 different technologies for inertia provision can entail ownership by either network operators or market parties (although some technologies can be owned and operated by either). Since the processes for securing inertia from network operator- vs market-owned assets are very different (market-based procurement mechanisms vs regulatory approval of network operators' investment plans), a choice must be made on how and in which sequence to combine network operator- and market-owned assets.

Furthermore, article 40(5) of the Electricity Directive (EU) 2019/944 requires TSOs to procure non-frequency ancillary services[94] in a transparent, non-discriminatory and market-based procedures, enabling the participation of all qualified electricity undertakings and market participants, unless the NRA provides a derogation on the ground that market-based provision is not economically efficient. For example, the German regulator has issued in 2020 a derogation[95] in this regard, although recently a decision has been made on the introduction of a market-based procurement mechanism as detailed in section 3.3.

Thus, the Electricity Directive clearly prioritises market-based procurement. A hybrid approach would thus prioritise market-based procurement while using TSO-owned assets to cover any inertia gaps needed to ensure system security. Such a hybrid approach can be implemented in the following way:

1. **TSO inertia needs and reserve price definition** - To ensure cost-effectiveness, the TSO establish and publish ahead of the tender a reserve price (for example representing the cost at which they could provide inertia using their own assets or by procuring additional reserves in the balancing markets). This reserve price acts as a benchmark ceiling for evaluating

[93] ENTSO-E (2025) Position Paper. Project Inertia – Phase II - Recovering power system resilience in case of system splits for a future-ready decarbonised system

[94] Article 2(49) of the Electricity Directive includes "inertia for local grid stability" in the definition of non-frequency ancillary service

[95] BNetzA (2020) Resolution BK6-20-298

market bids. Furthermore, TSOs define the inertia volumes to be procured based on inertia needs assessment (taking into account that procurement of inertia needs maybe be split in tenders with different maturities, e.g. to leverage existing market-owned assets as well as procure services from new or upgraded assets).

2. **Market-based procurement** – The TSO launches tender(s) for procurement of inertia services, indicating the volumes to be procured and the reserve price. Qualified market participants, including generators, storage operators, and other providers submit bids reflecting the price at which they are willing to supply inertia. The tender can include the procurement of other ancillary services, such as voltage control.
3. **TSO reserve price and bid evaluation** - The TSO clear the tender, accepting bids from market participants if the offered price is lower than or equal to the reserve price, up to the procurement volume. Bids that exceed the reserve price are rejected, since the TSO-developed assets (or other back-up approaches) offer a more cost-efficient solution. By using this reserve price mechanism, TSOs ensure the prioritisation of market-based resources while safeguarding against unnecessary costs, including the possibility of strategic behaviour of market participants.
4. **Deployment of TSO-owned assets or other solution as backup** - If the market does not supply sufficient inertia at prices below the reserve price to meet the inertia needs, the TSO will deploy its own assets to fill the gap upon regulatory approval, or for example procure the additional inertial response from qualified assets bidding in TSO balancing markets. This ensures system stability without relying solely on market outcomes. TSO-owned assets act as a reliable fallback, especially in regions with low market participation or insufficient inertia bids.

Alternatively, and considering that not only TSOs but also DSOs might deploy inertia-capable assets for the provision of other ancillary services such as voltage control, competition can be stimulated not only between market parties, but rather between market parties and network operators. In this way, for example DSOs could be remunerated for providing inertia services. A similar approach is currently applied by NESO in the stability network services program.[96]

Several potential **synergies** would arise from such a hybrid approach:

- **Cost efficiency**: Market-based mechanisms serve as the primary means of securing inertia, ensuring that services are procured at competitive prices. TSOs procuring the service only deploy their own assets (or other back-up solutions) when bids from market-participants (and possibly DSOs) exceed the reserve price, preventing unnecessary investments. This reserve price mechanism acts as a safeguard to maintain affordability while ensuring system needs are met. It also fosters disciplined bidding behaviour among market participants. Knowing that TSO-owned assets or other approaches will be deployed if their bids exceed the reserve price, market players are incentivized to submit competitive and realistic offers.
- **Flexibility in procurement**: TSOs can dynamically adjust their reserve price and procurement strategies based on evolving market conditions, technological advancements, and operational needs. This adaptability ensures that the most efficient mix of market-based and regulated solutions is applied in real-time.
- **Optimized coverage of system needs**: By first leveraging market and other network operators' participation, inertia provision is sourced from the most cost-efficient locations. TSO-owned assets can then be strategically placed in areas where market mechanisms fail to provide the required inertia. This ensures a reliable and efficient balance between market-driven solutions and TSO investments.
- **Leveraging innovation while ensuring sufficient inertia levels**: Market-based procurement encourages the development of innovative grid-forming solutions. At the same time, the

[96] NESO (s.d.) https://www.neso.energy/industry-information/balancing-services/network-services/stability-network-services

presence of TSO-owned assets provides a reliable fallback option and ensures that inertia requirements are consistently met, mitigating the risks associated with market volatility or underinvestment. This combination promotes technological progress without compromising grid security.

While the hybrid approach offers several advantages, it also presents certain challenges that must be addressed for successful implementation:

- **Reserve price calibration**: Determining an appropriate reserve price for TSO-owned assets or other approaches is a complex task. If the reserve price is set too high, market participants may receive excessive payments for inertia services. Conversely, if the reserve price is set too low, it may discourage market participation, undermining competition and innovation.
- **Market uncertainty and volatility**: The hybrid model depends on a functional and liquid inertia market. However, insufficient market participation or volatile price signals could hinder the system's effectiveness. In scenarios where market participation remains low or market-based procurement mechanisms fail to mature, TSOs may end up relying too heavily on their own assets.
- **Operational complexity**: Coordinating the deployment of market-procured inertia and TSO-owned assets requires sophisticated operational systems and real-time decision-making. TSOs will need to develop advanced tools for inertia forecasting, market monitoring, and rapid response
- **Compatibility with short-term procurement**: Shorter-term tenders, such as (sub)monthly or Y-1 inertia procurement, TSOs lack sufficient time to react to market shortfalls by developing their own assets. Hence, any short-term markets need to be combined with the long-term development of term market- or network operator-owned assets.
- **Delayed TSO investment decisions**: TSOs would typically initiate the development of their own inertia-providing assets only after market-based procurement fails to meet system needs. This reactive approach means TSOs may need to wait a year or two before knowing if the market will provide sufficient long-term inertia resources, resulting in longer lead times for asset deployment. While this may not pose significant concerns for long-term system planning, it could limit the ability to respond to unexpected inertia shortfalls in the nearer term.

4.3.3. Design of dedicated procurement mechanisms

A procurement mechanism for inertia (and other ancillary services) can be designed in various forms, for example regarding the inertia product definition, procurement timeframe, and specific system requirements. This section outlines key design elements and presents options that may be considered in establishing such a mechanism.

It will be necessary to strike a balance between an adequate market design **enabling the participation of small and new inertia service providers** and not over-complexifying the mechanism. A number of features mentioned below will be relevant to enable the participation of such service providers, such as the minimum inertia product size, use of symmetric or asymmetric products, procurement horizon, and other features.

Define the inertia product

A key element of designing a dedicated procurement mechanism is to **define the inertia product**. The product definition should include:

- **Minimum and maximum inertia contribution**: Defined in terms of e.g. equivalent kinetic energy (MW.s or MVA.s) or power for a given RoCof (MW.s^2) that a provider must deliver, as well as whether the inertia is to be provided continuously or dynamically upon specific events, and maximum output (if applicable).

- **Minimum response time, duration of service and recovery period**: Specifies how quickly the service must be available after a system event, how long it must be sustained and how soon it must be available again following the resolution of the disturbance.
- **Product direction**: to positive or negative RoCoF changes, or symmetric. Many IBRs might not be able to provide upward inertia services unless they have internal storage, meaning the potential for provision of downward inertia services might be larger and thus procurement costs lower. However, having two asymmetric products would make the procurement mechanism more complex;
- **Procurement horizon**: The contractual length or timeframe of the product must also be clearly defined. The selection of product duration will influence procurement timelines, market liquidity, and the mix of eligible technologies, and must be aligned with the system's long-term inertia needs and planning processes. The next subsection discusses this element in more detail;
- **Availability requirements and possibility of value stacking**: participants will be active not only in inertia but also balancing, congestion management and spot markets. Hence, TSOs will need to define the possibility for service providers to stack the provision of certain services, aiming to maximise the possibility of value stacking while considering system security needs and the technical constraints of different technologies.

Procurement horizon for inertia services

The timing of inertia procurement — how far in advance services are secured — is a critical design element of the procurement mechanism. The procurement horizon(s) must align with the nature of the assets involved, the predictability of system needs, and the flexibility of the procurement model. Inertia can be procured over different timeframes, each serving a specific purpose:

- Multi-year ahead procurement (Y-2 or above): This long-term procurement horizon is required for new investments with a long lead time for permitting, financing, and construction. This can include new investments in synchronous condensers, repurposed thermal plants, or large-scale grid-forming battery systems. These assets require long lead times Typically such procurement is coupled with multi-year contracts to provide the investment certainty needed for such projects and support strategic system planning, where new investments might require very long contract durations of e.g. 10 years, while upgraded assets might require shorter durations of e.g. 3 years, such as in Great Britan. [97]

- Year-ahead procurement (Y-1): Annual procurement of inertia services can accommodate existing, flexible assets that do not require new development, such as operational battery systems, generators, or demand-side response aggregators. Year-ahead contract durations would then balance market flexibility with sufficient notice for operational planning.

- Month-ahead procurement (M-1): Monthly procurement may be used to fine-tune inertia volumes based on updated seasonal system forecasts or evolving generation patterns. It is well-suited for topping up long-term inertia commitments with short-term, flexible services that can respond to changing system conditions.

- Day-ahead procurement (D-1): While not yet widely used for inertia (although being planned for Great Britain), day-ahead procurement could in theory support highly responsive assets such as batteries with grid-forming inverters which would have otherwise an important opportunity cost (e.g. not knowing if they would be operational considering spot market clearing). However, because system inertia must generally be available continuously, D-1 procurement can be more applicable to complementary services like fast frequency response (FFR) rather than inertia provision itself, but it could make-up for critical shortfalls.

[97] NESO (s.d.) Stability Network Services

The timeframes are not mutually exclusive. Long-term contracts can ensure baseline inertia, ensuring system stability and enabling infrastructure investments, while using shorter-term procurement is well placed to adjust volumes based on operational forecasts or emerging needs.

Price setting

Prices for procuring inertia services can be determined in two main ways: market-based pricing or administrative pricing. Each method has distinct implications for efficiency, investment signals, and market dynamics.

Market-based pricing: In this model, inertia services are procured through competitive auctions or bidding mechanisms, where providers submit offers and the market determines the clearing price based on supply and demand. As discussed earlier on in this section, a key feature of marked-based pricing is the use of a TSO-defined reserve price, which e.g. represents the cost at which the TSO could provide inertia using its own assets. The reserve price acts as a benchmark against which all market bids are evaluated. Market-based pricing has the following advantages:

- Competitive bidding incentives cost-efficient provision of inertia services.
- Providers have incentives to develop cost-efficient inertia services
- Prices discovery emerge from competition, reducing the risk of under- or overpayment due to inaccurate cost estimates in the long-run

Disadvantages of market-based pricing include the following;

- Risk of strategic bidding, especially if there are only a few parties to provide inertia services, or when there are dominant big players
- Large price fluctuation, creating investment uncertainty for potential new market parties
- If participation in these auctions/bidding mechanisms is low, competition may be too little to guarantee fair pricing.

There are a number of additional aspects that can be considered for market-based pricing, including using pay-as-bid or uniform pricing in inertia auctions. However, such details are not analysed further in this study.

Administrative pricing: Under this approach, prices are set by the system operator or regulatory authority, based on estimated costs, return-on-investment benchmarks, or comparative market analysis. Administrative pricing may take various forms, including cost-based pricing (e.g. upon audit of accounts), regulated fixed payments, or performance-based compensation, where pricing is linked to factors such as reliability or contribution to system stability. This approach has the following advantages:

- Avoids volatility, providing longer-term certainty for (new) market participants
- Prevents market abuse/strategic bidding
- Less complex than auction and no need to hedge against strategic bidding

The difficulties of administrative pricing include the following:

- Inefficiency risks as prices may not reflect true market conditions, leading to over- or underpayment
- Lack of competitive pressure, as there are no direct incentives for providers to reduce costs or innovate
- Regulatory burden, as cost assessments, ongoing adjustments and risks of inaccurate price settings need to be performed and monitored
- One-size-fits-not-all-problem; fixed prices may not work well for different providers or regions

Overall market-based pricing (combined with appropriate safeguards such as the use of reserve prices in auctions) should be preferred when procuring resources from market participants and other network operators, given the downsides of administrative pricing indicated above.

Strategic behaviour

Dedicated procurement mechanisms for inertia may expose the system to **strategic behaviour by market participants,** particularly due to technical characteristics of inertia needs, such as the need to geographically distribute resources. If not adequately addressed through robust design and oversight, such behaviour can undermine cost-efficiency, fairness, and system security. Several forms of strategic behaviour may emerge:

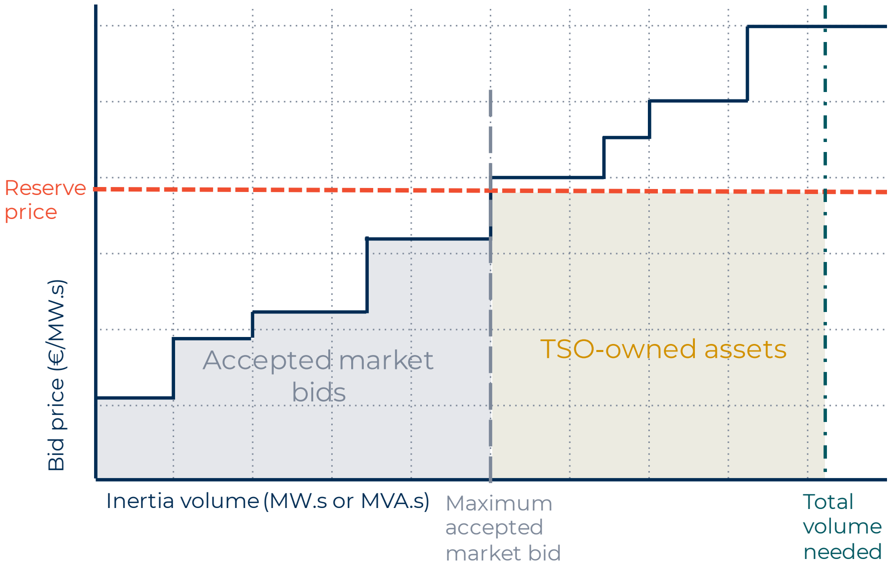
- **Market power abuse**: In markets with limited competition or dominant players, providers may exercise market power by inflating prices or withholding capacity to influence outcomes.
- **Gaming procurement rules**: Participants may exploit loopholes in auction design, eligibility criteria, or bid evaluation rules to secure higher payments or gain competitive advantage.
- **Technology-based price inflation**: If procurement rules unintentionally favour certain technologies (e.g., by over-specifying product characteristics), suppliers of those technologies may artificially raise prices, knowing their assets will be preferred.
- **Regulatory arbitrage**: Providers may allocate resources not based on system needs but in ways that maximize remuneration across different market segments, timelines, or contract terms. When procurement mechanisms include zonal or locational targets, or apply locational price weightings, participants may concentrate assets in those higher-value zones - not because of technical suitability, but to maximise revenue. This may lead to inefficient asset placement, over-concentration in incentivised zones, and price inflation in areas with limited competition.

Assessment of tenders

The assessment of tenders is a critical component of the dedicated procurement mechanism for inertia. Two principal approaches can guide this assessment: price-based procurement and procurement based on predefined volumes. In a price-based approach, all bids that meet the technical requirements and are offered at or below the TSO-defined reserve price are accepted. When procurement is done on predefined volumes, all bids are accepted until the required volume is reached.

In practice, a combined approach is better suited. In this case, bids are ranked and accepted until either (i) the required volume is reached, or (ii) the submitted bids exceed the reserve price threshold - whichever occurs first. If the target volume cannot be met through the market bids (i.e., those below the reserve price), the TSO then proceeds to develop and deploy TSO-owned assets to cover the remaining inertia gap. This approach is visualised in Figure 4-2 below.

Figure 4-2 Combination of market bids and TSO-owned assets in procurement mechanism



Regardless of the auction structure, TSOs must ensure that procurement processes are conducted in a **transparent and fair manner**. This includes:

- Publishing procurement rules and eligibility criteria in advance;
- Ensuring non-discriminatory access for all eligible service providers;
- Publishing procurement outcomes, such as awarded volumes and clearing prices; and
- Establishing clear dispute-resolution mechanisms to address challenges or grievances from participants.

Locational signals

A number of locational considerations affect inertia needs and the capability of inertia resources:

- Inertia resources will need to be **geographically distributed** in the first place, given system splits are a major determinant of inertia needs. Certain regions or control areas may be more vulnerable to frequency disturbances or grid separation events due to lower levels of naturally occurring synchronous generation, weaker network interconnections, or local system topology;
- The effectiveness of **inertia resources** can furthermore vary depending on where it is provided within the grid.

Hence, **locational signals** within the procurement mechanism can be introduced to ensure that inertia is delivered where it is most needed to maintain grid stability. These can be embedded in the procurement mechanism in several ways:

- **Zonal or locational procurement targets**: the TSO may define minimum procurement volumes to ensure adequate inertia coverage in specific grid zones. These targets can help prevent under-procurement in vulnerable areas that may not naturally attract market bids due to higher costs or limited competition. A way to implement these procurement volumes could be via **flexible volume allocation**. In this method, locational procurement targets are set but their sum is set below the total tender volume, giving the TSO flexibility in achieving an optimal balance between cost efficiency and spatial adequacy. A portion of the total inertia volume needed is location-independent and is procured wherever most cost-efficient, while another portion of the inertia volume is subject to locational targets.
- **Locational price signals or weighing factors**: To reflect the higher system value of inertia in certain areas, the procurement mechanism could apply locational multipliers or weighing

factors to bids. This approach adjusts the relative ranking of bids in the tender evaluation process, favouring inertia provision in critical zones.

Payment structure

The payment structure is a key element of the dedicated procurement mechanism, as it defines how service providers are remunerated and incentivised to deliver reliable inertia services. A well-designed payment model ensures that providers are adequately compensated while maintaining accountability for performance. The procurement mechanism may include the following components:

- **Capacity payment**: a fixed payment for the availability of inertia capacity, regardless of whether the service is actively used. It ensures that providers are compensated for making their assets available to the system operator and for maintaining the technical readiness to deliver inertia when needed. Capacity payments offer revenue stability for service providers, particularly in long-term contracts, and help attract investment in inertia-providing infrastructure.
- **Delivery payment**: While inertia is inherently a capacity service, activation payments might be appropriate to cover energy costs of delivery as well as opportunity costs in the case of short-term contracts.[98]
- **Performance-based penalties or bonuses**: payments linked to the quality and reliability of the service delivered. Penalties may apply in cases of non-availability, underperformance, or failure to comply with technical specifications. Conversely, bonuses may be awarded for high availability, accurate delivery, or exceeding predefined performance thresholds. This component strengthens accountability and encourages providers to maintain high service standards throughout the contract period.

4.3.4. Harmonisation of inertia securement at the European level

An important consideration in defining a regulatory framework for inertia is whether there should be harmonisation at the European level of national inertia securement aspects. The degree of harmonisation among Member States can influence the efficiency, flexibility, and resilience of inertia securement across interconnected electricity markets. This section covers the potential introduction of harmonisation requirements, and does not cover actions which would be taken jointly at the EU level in the first place (such as estimating future inertia levels within the TYNDP process, and defining synchronous area inertia needs and allocating those to each node).

Aspects subject to harmonisation could include:

- **National inertia assessment methodologies**: A harmonised methodology for further refining additional inertia needs at the national level (to meet national targets agreed at EU level), establishing locational requirements within control areas, and defining volumes to be procured from the market.
- **Framework for national market-based mechanisms**: Covering for example uniform product definitions, procurement timelines, and participation rules in a common framework for market-based procurement.
- **Guidelines for NRAs derogating TSOs** from the need to employ market-based mechanisms to secure inertia, including for example details of when a market-based approach can be considered as not economically efficient;
- **Joint market platform**. A common market structure could comprise synchronous area or regional inertia tenders, for allowing nodes to meet inertia targets by using inertial resources from neighbouring nodes (up to defined thresholds, considering the limits of regional inertia exchange and the need for geographically-distributed inertia resources). This is described in the dedicated section below.

[98] AFRY and NESO (2023) National Grid ESO Stability Market - Design: Final Outcomes

Two distinct approaches can be considered: harmonisation at the European Level or a non-harmonised (national or regional) approach.

- **Harmonisation at European level** could be particularly relevant if a market-based approach becomes more widespread considering the EU Electricity Directive does require it except in case the NRA provides a derogation. Fragmented or inconsistent market-based mechanisms in each Member State could undermine efficiency and limit liquidity (more on this below). The benefits of such harmonisation could include regulatory certainty and transparency (clarifying certain procurement aspects for all Member States at once, facilitating long-term investments in inertia-providing solutions), data transparency and price discovery (ensuring certain information is published along specific formats, and facilitating the discovery of costs for securing inertia across the EU). Disadvantages of a harmonised approach could include complex regulatory implementation, and the risk of excessive centralisation / lack of national flexibility.
- In the **non-harmonised approach**, national actors retain autonomy over inertia procurement and asset deployment within their own control areas, without a binding framework for EU-wide coordination in any of the mentioned aspects. Each NRA and TSO design their own procurement mechanisms. This would allow for tailored solutions for national systems, potentially faster implementation and allow national framework to adapt more easily to changing circumstances. Disadvantages of a non-harmonised approach could include the risk of market distortion (if e.g. certain operators in specific regions are able to derive significant revenues from inertia provision compared to neighbouring operators), and the risk of inefficiencies / investment redundancy (e.g. over-procurement of inertia in certain regions).

At present, it seems there is **no urgent need for harmonisation** at the EU level regarding inertia procurement. Currently, additional inertia needs remain relatively low and few TSOs remunerate inertia procurement in the Continental Europe SA, although e.g. Germany is implementing a market-based mechanism. However, as the energy transition progresses, the support from synchronous generators will decrease, increasing the risk of frequency instability and large disturbances. ENTSO-E's future system studies indicate a significant rise in system split cases exceeding the ±1 Hz/s RoCoF threshold, with blackout risks growing from 2030 to 2040.

Another consideration of the need for EU-level harmonization is the volume of inertia procurement compared to the other electricity markets. Unlike energy or balancing markets, where large-scale cross-border exchanges occur regularly, inertia services will need to be geographically distributed to a large extent. Moreover, additional inertia needs remain small in most cases in the CE SA. As a result, the risk of cross-border market distortion is relatively limited at this stage. Even if national or regional procurement mechanisms vary, the financial impact of potential distortions is unlikely to be significant compared to other market activities. Moreover, inertia needs and system characteristics vary significantly between regions. Some TSOs already face challenges due to high shares of non-synchronous generation, while others still benefit from sufficient inertia in their existing generation fleets. This heterogeneity means that a one-size-fits-all approach may not be the best solution at this stage.

These factors support a cautious approach toward harmonisation. If future inertia needs increase and market-based procurement becomes more prevalent, the potential for cross-border impacts may grow. While harmonisation may become necessary in the future, current system conditions do not yet justify an urgent push for EU-level harmonisation. Instead, a phased approach, allowing TSOs to implement tailored solutions, may be more appropriate for now.

This phased approach could further explore especially **guidelines for NRAs derogating TSOs from market-based procurement**, and **harmonized inertia product definitions at EU level**. Aligning the terminology and key technical parameters and service requirements - such as minimum response time, duration, and measurement and verification standards - would reduce entry barriers for service providers and enhance interoperability across national markets. Such harmonization of definitions can bring clear benefits for balancing service providers and technology manufacturers. For service providers operating across borders, aligned product requirements would allow them to bid into multiple national or regional inertia markets without needing to adapt to differing technical specifications, qualification procedures, or contractual arrangements. Similarly, for suppliers of inertia-providing technologies (i.e. solution providers), harmonisation would simplify the development and deployment of their equipment.

Joint procurement or regional exchange of inertia resources

This section explores various more ambitious approaches for bilateral or regional cooperation between TSOs for the exchange of inertia resources. It must be noted that there are limitations/disadvantages to each approach mentioned, and these are hence not necessarily advocated for.

Since inertia could theoretically be exchanged across borders (with important potential limitations as discussed at the end of section 2.3.1), it might be cost-optimal to do so although it would entail significant coordination complexity and there is no appropriate cost-benefit analysis on the topic. This is based on the idea that some nodes may have surplus assets capable of providing inertia at a lower cost others. The trading or sharing of inertia could be done in a similar manner to the current approach used for sharing FCR.

In the FCR Cooperation initiative, the coordinated needs assessment and procurement of FCR is now done in 12 load frequency control (LFC) areas spanning 9 countries in Continental Europe. The FCR Cooperation follows a TSO-TSO model, in which FCR is procured through a shared merit order list, combining offers from all participating TSOs. While the procurement process is centralized, interactions with Balancing Service Providers (BSPs) and contractual agreements remain managed at the national level, ensuring each TSO oversees the delivery responsibilities within its jurisdiction. With FCR, there is both a maximum export limit and a minimum amount that must be procured within the own LFC area, known as the core share constraint. The minimum amount to be procured locally is 30%, and the maximum export limit is either 30% of the required FCR of the exporting country or at least 100 MW.

Similar to FCR, there might be a possibility of having one centralized market where all asks and bids are optimized together. Here again, there will be a minimum inertia requirement for each LFC area to ensure a baseline level of local inertia considering the possible system splits and other factors, thereby preventing local RoCoF issues. And again similarly to the FCR case, there is a case to be made to also propose a maximum amount that can be exported from one country, to not be too reliant on one country because of the risk of interconnector failures.

A second option is to allow international participants from outside the node to bid into the local inertia market. However, this option is less preferred as it does not guarantee welfare optimization. Since participants would be unable to bid into multiple markets, it is unlikely that the optimal allocation will be achieved, as compared to the first option.

A final, less favourable option is to allow TSOs to trade inertia services bilaterally. If one TSO has significantly more inertia-providing assets or can provide them at a much lower cost, this could be pursued. However, due to high transaction costs and the lack of coordination, this option is also not preferred.

4.3.5. Co-optimisation with wholesale and/or balancing markets

An alternative to dedicated procurement mechanisms is the co-optimisation of inertia within existing markets, particularly the wholesale (day-ahead) and balancing markets. In such co-optimisation, inertia needs are incorporated as an explicit constraint or objective during the market-clearing process. This approach leverages the liquidity and structure of existing markets while ensuring that inertia is factored into market clearing. Rather than procuring inertia through a separate tender, inertia-providing resources would be prioritised within the standard market-clearing process, provided they remain cost-competitive.

Co-optimisation with wholesale markets

A method for implementing **co-optimisation with wholesale markets** involves introducing constraints in wholesale markets to ensure minimum inertia levels. In theory, inertia constraints can be implemented in EUPHEMIA, the day-ahead market algorithm used to clear Single Day-Ahead Coupling (SDAC) across Europe. This would require modification and an additional criterion for the selection of eligible assets (e.g. inertial response-ready producers, storage and HVDC inverters) in the merit order to ensure at any time the effective availability of the minimum required inertia level per bidding zone or group of bidding zones. This could be done by;

- tagging inertia-ready units in the market bids
- enforcing a constraint that predefined amount of inertia per node must be secured during market clearing
- adjusting the merit order, e.g. in a way when multiple bids are economically similar, those offering inertia are given priority to ensure compliance with the inertia constraint.

It has the benefit of avoiding the need for a separate procurement mechanism and provides clear investment signals for assets capable of providing inertia. Moreover, it could implicitly lead to additional revenues for inertia-providing units, which would be prioritized to a certain extent over other units. However, this co-optimisation has severe challenges;

- It requires significant modifications to complex market algorithms like EUPHEMIA. As the algorithm becomes more complex, computational challenges could arise, especially as markets shift towards shorter gate closure times and smaller market time units. Although such co-optimisation is already implemented in balancing capacity markets in jurisdictions like the U.S., applying a similar approach to inertia in European day-ahead or intraday markets would still involve numerous design and operational hurdles.
- It would require information on the units fulfilling the offers, including technology and perhaps location within bidding zones.
- It increases complexity of the selection process, which is which is now only based on the price of the offered capacity. This makes the market less transparent and predictable for market participants.
- It causes greater uncertainty to (renewable) generators without inertia capabilities, who may face increased difficulty in estimating whether their bids will be accepted, despite generally lower marginal costs compared to other generators.
- It could increase clearing prices in some zones, depending on the availability of inertia-providing resources. This could lead to displacement of lower-cost, non-inertia resources and reduce overall market efficiency.

Given these challenges, while the concept of co-optimising inertia with wholesale market operations is technically feasible, this approach is not recommended.

Co-optimisation with balancing markets

Co-optimising inertia within balancing markets is an approach that integrates inertia provision into the procurement of balancing reserves. This approach could have several advantages; it allows for system-wide optimisation as it allows TSOs to consider both balancing and inertia needs simultaneously, potentially reducing total system costs and avoiding redundant procurement. In addition, it efficiently uses existing platforms as it builds on the structure and liquidity of the balancing markets. A UK study (cf. 8.2.15) discussed the importance of linking inertia and frequency response in the context of the Great Britain power system. In this study, a Stochastic unit commitment model is considered to allow for optimal scheduling of energy production and ancillary services while accounting for uncertainties inherent in renewable energy generation. The key findings of this study indicate that an unlinked approach - so separation in inertia and frequency response procurement - significantly increases system costs, particularly in a future scenario with higher wind capacity and a larger potential loss due to generation outages.

From the other hand, there are several important considerations that need to be taken into account for developing this approach into practice. These are as follows:

- When considering co-optimisation within balancing markets, it is important to distinguish between capacity provision and activation - especially in the context of market timelines and the physical characteristics of inertia. As inertia is a passive, instantaneous response, it is not an activated service in the traditional sense (but neither is FCR). Inertia is delivered automatically and immediately upon a frequency disturbance. As a result, a real-time activation market for inertia is not feasible, and there will be no need to establish one. Instead, inertia must be secured through capacity-based mechanisms, where the system operator procures and commits inertia-providing units in advance. This makes it conceptually similar to procuring very fast balancing capacity or FCR, although it serves a fundamentally different technical purpose.
- Another consideration when considering co-optimisation of inertia within balancing markets is that many generators and batteries providing inertia will already be active in spot markets. In these cases, inertia is delivered inherently, without needing additional incentives. Introducing a separate payment could be considered double compensation and a reduction of overall efficiency. On the other hand, market operators could internalise the potential revenues from inertia provision in their balancing (or wholesale) market bids. Therefore, a choice must be made on whether to avoid paying for inertia that is already being provided as a by-product of energy dispatch. The Great Britain stability market design explicitly aims to remunerate only additional inertia, and not what it calls associated inertia.[99] The value of co-optimisation would in this case primarily ensuring that marginal inertia gaps - particularly during system stress conditions or in weak grid areas - are covered by incentivising the right resources to be online.

  Related to this is the cost asymmetry between different types of inertia resources:
  - Synchronous generators inherently provide inertia whenever they are synchronised to the grid. If they are already scheduled to provide energy or balancing capacity, their inertia contribution comes at no additional cost - even if the system does not explicitly pay for it, they must physically provide inertia to remain grid-connected.
  - Inverter-based units on the other hand, must actively reserve capacity and configure their systems to deliver inertia. This may involve an opportunity cost, as doing so may limit their ability to deliver energy or other ancillary services. Therefore, to secure inertia from these assets, the market must provide explicit compensation for inertia capacity, even if the service is never "activated" in real time and needs to differentiate remuneration according to the type of provider.

  A market mechanism could therefore pay only inverter-based units for inertia, recognising their opportunity cost, while assuming that synchronous generation provides inertia as a co-product of energy or reserve provision. However, in situations of inertia scarcity, it may be necessary to incentivise synchronous machines that are out of merit from an energy price perspective to come online. In these cases, payment for inertia services would serve as a lever to bring these units back into the merit order—not for their energy, but for their system-stabilising inertia contribution. Hence, this approach needs to enable targeted activation of out-of-merit inertia providers when system conditions require it.

So, while real-time inertia activation markets are not appropriate, capacity-based procurement and co-optimisation within balancing markets is theoretically possible. However, such a mechanism must be carefully designed as there are several important considerations that showcase the challenges of this approach.

[99] AFRY and NESO (2023) National Grid ESO Stability Market - Design: Final Outcomes

4.3.6. Possible approaches for connection requirements for generators and storage operators

The currently applicable **connection requirements for generators** (and pumped hydro installations) were published in 2016 (Commission Regulation 2016/631).[100] Art 15 has an indirect impact on the inertia needs; it foresees that if the delay in initial activation of active power frequency response is greater than two seconds, the power-generating facility owner shall provide technical evidence demonstrating why a longer time is needed. For power-generating modules without inertia, the relevant TSO may specify a shorter time than two seconds. Art 21 foresees that TSOs have the right to specify that power park modules be capable of providing synthetic inertia during very fast frequency deviations.

Member States were legally obliged to implement this EU Network Code by May 2018. The implementation status has been presented in a 2021 study commissioned by DG Ener.[101] This study reveals that in 2020, 17 countries had to some extent implemented the requirement on type B, C and D PPMs[102] to provide synthetic inertia, while 3 countries did not have such a requirement and for 15 countries, the information was not available.

The EU **Network Code on demand connection** (Commission Regulation 2016/1388) does not include specific references to inertia. In Recommendation No 03/2023, ACER did propose amendments to the **Network Codes on Requirements for the Grid Connection of Generators and Demand Facilities.**[103] These amendments aim to ensure that new generators can actively support grid stability, including through grid-forming capabilities for voltage support. Specifically, the recommendation introduces non-mandatory provisions for Type A generators, while setting out mandatory requirements for Types B, C, and D generators, which are typically larger and more impactful on system stability.

To maintain consistency across grid connection rules and to address emerging system needs - particularly those arising from increased offshore and cross-border electricity flows - ACER further launched a complementary amendment process for the **HVDC Grid Connection Network Code** through its Recommendation No 01/2024, issued on 19 December 2024.[104] This recommendation proposes updates to Commission Regulation (EU) 2016/1447, which governs the grid connection of high-voltage direct current (HVDC) systems and DC-connected power park modules.

Given the growing deployment of HVDC infrastructure - especially for offshore wind, interconnectors, and storage - Recommendation No 01/2024 places strong emphasis on enhancing the performance of grid-forming converters. It proposes the formal introduction of technical requirements for grid-forming capability, enabling these systems to contribute to frequency and voltage stability in an evolving, converter-dominated power system.

While network users such as the ones indicated above and some large industrial consumers may be technically capable of supporting grid stability, including frequency-related services, it is not considered appropriate to impose inertia-related obligations on electricity users via connection requirements. Instead, such potential contributions should be triggered by voluntary participation in market-based mechanisms. Nonetheless, as per ACER's recommendations, network users could be mandated at the EU or national level to have the capability to provide certain ancillary services (such as inertia or voltage control), based on a cost-benefit analysis of the associated costs and the remuneration for the users which do end-up providing these services.

It should also be acknowledged that market participants have expressed **opposition to certain regulatory approaches in this context**. In particular, stakeholders have raised concerns about TSOs

[100] Requirements for Generators
[101] Implementation of the network code on requirements for grid connection of generators
[102] Classification of Power-generating modules (PGM): (a) connection point below 110 kV and maximum capacity of 0,8 kW or more (type A); (b) connection point below 110 kV and maximum capacity at or above a threshold proposed by each relevant TSO in accordance with the procedure laid out in paragraph 3 (type B); (c) connection point below 110 kV and maximum capacity at or above a threshold specified by each relevant TSO in accordance with paragraph 3 (type C); or (d) connection point at 110 kV or above (type D).
[103] ACER (2023), Recommendation No 03/2023 of ACER
[104] ACER (2024), Recommendation 01/2024 of ACER

introducing technical inertia capability requirements for new assets through connection codes, arguing that such mandates place undue investment obligations on developers. Additionally, there is resistance to any form of obligatory or non-remunerated provision of inertia services. Market actors stress that providing inertia services entails both capital and opportunity costs. Therefore, these market parties emphasise the importance of fair compensation and market-based procurement frameworks that incentivise flexibility and innovation, rather than imposing unfunded technical requirements. Without appropriate compensation mechanisms, such requirements are viewed as distortive, undermining investment certainty and innovation.

Given these considerations, it is essential that **NRAs** play an active **oversight role in the introduction of such requirements**. Any new obligation placed on generators, storage operators, or other network users, should be subject to strict regulatory scrutiny and approval. This oversight is necessary to ensure that technical justifications for new requirements are well-founded, aligned with actual system needs and guarantee, proportionate (considering costs to both asset owners and solution providers as well as the broader sector), and consistent with EU regulatory frameworks. NRAs and TSOs should also ensure that such requirements are harmonised where appropriate, while maintaining the flexibility to reflect national or regional system characteristics. Furthermore, they should facilitate transparency and facilitate stakeholder involvement in the process of deciding on, introducing or updating connection requirements regarding inertia capabilities.

4.3.7. Development and timing of a EU regulatory framework for inertia

While no immediate EU-level regulatory action is required to be in force by 2030, the need for **additional inertial resources in the CE SA is already emerging within this timeframe**. ENTSO-E foresees that an additional 73 GW.s of inertia would be necessary to ensure 2 sMW/MVA inertia constant in all CE SA countries for 50% in 2030, and an additional 267 GW.s to reach a 90% target. Our own analysis also indicates the need for additional inertial resources already in 2030, increasing further to 2040 and 2050 depending on the system split scenario considered (section 2.3). Also, the impacts of any new regulatory measure will only be observed at the earliest close to 2030, given the policy cycle for proposing, agreeing on and implementing appropriate EU-level provisions takes several years.

The **development of a coherent framework for securing inertia at the EU and national level is a complex matter**, which needs to consider appropriate procedures for:

- Revision of connection requirements, where appropriate
- Assessment of inertia needs
- Allocation of identified needs across control areas
- Forecasting, short-term measurement and ex-post evaluation of actual system inertia levels
- Securement of inertia to make up for identified gaps from network operator or market-owned assets
- Inertia securement cost allocation between control areas and network users

This study addresses a number of questions:

- **How to combine the deployment of TSO and third-party owned assets?** Given the EU electricity market requirement for TSOs procuring inertia from third-party owned assets using a market-based mechanism (unless the NRA provides a derogation) and economic efficiencies of using existing third-party owned assets, the prioritisation of inertia service procurement with TSO-owned assets as a back-up is discussed;
- **What is the need for EU-level action and to what extent could inertia resources be exchanged at the regional level?** We highlight a number of potential areas for EU-level action, but indicate here there is a need for additional analysis on the costs, benefits and limitations of regional inertia exchange.

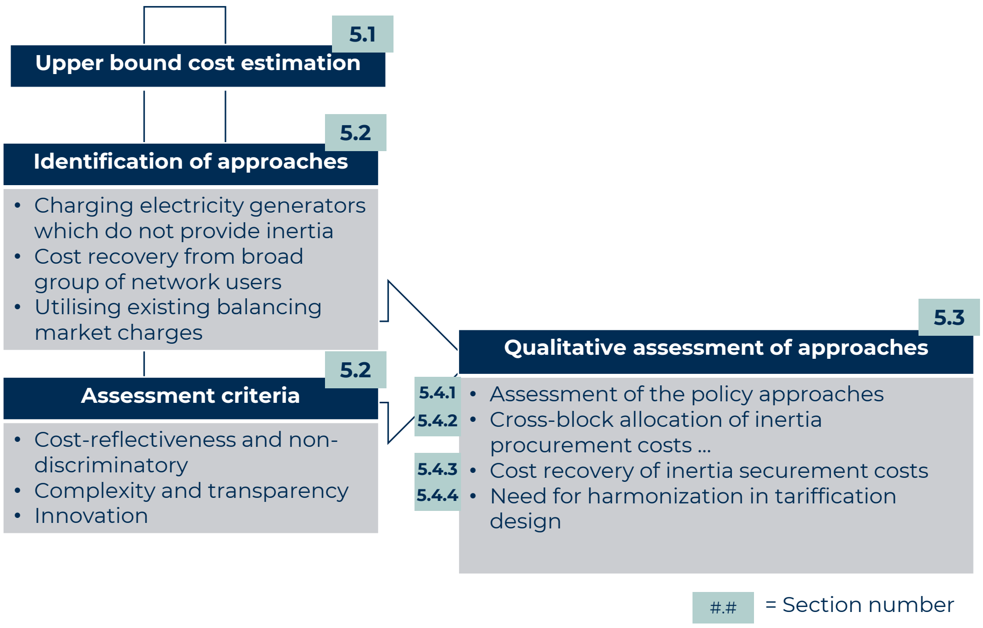
Therefore, we recommend immediate actions at the EU level but additional analysis is needed particularly regarding eventual regional exchange of inertia resources, while additional inertia resources are needed already in the 2030/2035 timeframe with needs increasing towards 2040/2050. **A timeline for introduction of regulatory measures could thus comprise:**

- In the **short-term (impacts by 2030/2035)** the European Commission, ACER, ENTSO-E and the EU DSO Entity move forward estimating inertia needs per synchronous area and defining national targets, with national authorities and TSOs introducing market-based mechanisms for inertia service procurement where needed (following non-binding EU guidance on the design of such mechanisms);
- In the **medium/long-term (impacts by 2040/2050),** further work is conducted to assess the costs, benefits and limitations of regional inertia exchange, and EU and national actors move forward to securing additional inertia resources (at the regional or national level depending on outcomes of the analysis) to meet enhanced reliability targets.

5. Assessment of options to recover costs of securing inertia

This chapter describes and evaluates identified options for TSOs to recover specific inertia-related costs from grid users. First, we provide an upper bound estimation of costs to meet inertia requirements. Then, similar to the previous chapter 4 in which the options to secure inertia are assessed, this chapter describes the assessment criteria, identifies the options to recover the specific procurements costs, and analyses their advantages and disadvantages as well as a number of related specific topics. The approach and different sections in this chapter are presented in the figure below.

Figure 5-1 Overview approach and sections of chapter 5



5.1. Estimation of an upper bound of costs to meet inertia requirements

The upper bound cost estimate is derived from the results in Section 2.3 and 3.1 where the inertia needs have been estimated and where indicative costs have been provided.

Two technologies are selected, with their respective annualized cost presented in Table 5-1*:*

- Synchronous condenser with flywheel
- e-STATCOM

Table 5-1 : Indicative technology costs

Technology	Synchronous condenser with flywheel	Converter addition (e-STATCOM)
Indicative Build Cost (k€/MWs.year)	2.2	2.9
Indicative O&M Cost (k€/MWs.year)	1.9-3.9	0.2-0.4
Indicative upper bound Total Cost (k€/ MWs.year)	6.1	3.1

Figure 5-1 shows that e-STATCOMs appear to be more cost-effective than synchronous condensers. However, as this technology is less mature, the associated cost estimates may be less reliable.

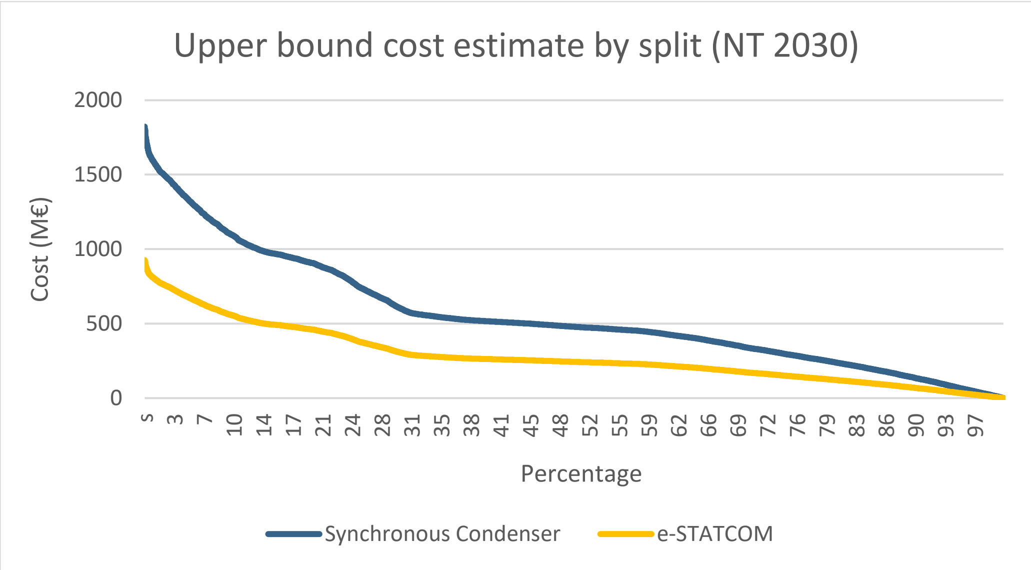


Figure 5-2 : Upper bound cost estimate

In 2030, the upper-bound annualised cost estimate is projected to range between €1,944 million and €3,593 million, increasing to between €2,301 million and €4,252 million by 2040. In comparison the annual total cost of balancing, which is the annual expense a TSO incurs for reserve procurement, energy activation, and imbalance netting, was estimated to be around 10 billion € in 2024 for the European Synchronous Area.[105]

[105] 240628_ENTSO-E_Balancing_Report_2024.pdf

Table 5-2 : Upper bound cost estimate NT 2030

2030	Iberian Split (Iberian side)	Italian Split (Italian side)	Balkan Split (Both sides)	3 Islands Splits (North-West side)	3 Islands Splits (West side)	Total
Additional inertia needed in 2030 (NT) [GWs]	97	299	0	174	19	589
Annual cost in 2030 with Synchronous condenser with flywheel [M€/year]	592	1824	0	1061	116	3593
Annual cost in 2030 with e-STATCOM [M€/year]	320	987	0	574	63	1944

Table 5-3 : Upper bound cost estimate NT 2040

2040	Iberian Split (Iberian side)	Italian Split (Italian side)	Balkan Split (Both sides)	3 Islands Splits (North-West side)	3 Islands Splits (West side)	Total
Additional inertia needed in 2040 (NT) [GWs]	142	332	0	206	17	697
Annual cost in 2040 with Synchronous condenser with flywheel [M€/year]	866	2025	0	1257	104	4252
Annual cost in 2040 with e-STATCOM [M€/year]	469	1096	0	680	56	2301

We estimate that the long-term cost of procuring system inertia could be up to €2–4 billion per year. There is still significant uncertainty around the actual future costs of securing enough system inertia. Estimating additional inertia requirements by summing up past system-split events only provides a rough idea of the potential costs. This method should be complemented with further studies that use probabilistic modeling and dynamic simulations to better reflect future scenarios and reduce estimation errors.

Costs could end up being significantly lower than the €2–4 billion per year depending on methodology assumptions and if certain strategies are implemented, such as:

- Faster energy release
- Improved redispatch strategies
- Revised connection requirements for specific network users

- Retrofitting existing infrastructure
- Increased market participation for inertia-providing resources
- Shared use of TSO assets for other services like voltage control or short-circuit protection
- Ability of HVDC line to remain connected after the tripping of AC lines in case of a system split

5.2. Identification of options to recover costs and assessment criteria

Based on the Terms of Reference and the analysis in the previous chapters, the following options to allocate and recover the specific inertia-related costs are considered:

- **Charging electricity generators which do not provide inertia**: Generators that do not contribute to system inertia may be required to pay a specific cost-reflective fee. This approach incentivizes the provision of inertia and helps offset the costs of additional stability measures needed to compensate for the lack of inertia from generators that are connected via inverters, and do hence not inherently provide inertia.
- **Cost recovery from broad groups of network users:** A broader approach may involve distributing costs across a wider base, including various consumer groups and different types of generators and/or storage operators. This method ensures that the responsibility for grid stability is shared more broadly, reflecting the collective benefit of a stable power system.
- **Utilising existing balancing charges:** Costs could also be recovered through existing balancing markets, such as incorporating them into existing balancing capacity mechanisms. By leveraging established market mechanisms, this approach integrates cost recovery into the broader framework of grid management.

The suggested criteria to assess the allocation and recovery of costs are:

- **Cost-reflectiveness and non-discrimination**, ensuring that the recovery methods align with the principle that costs are charged to the grid users that are responsible for inertia needs. The method should ensure that costs are recovered from those who primarily contribute to inertia needs while ensuring no undue disadvantages are imposed on specific groups.
- **Complexity and transparency**, making the cost recovery process clear and understandable for all stakeholders involved, and as simple as possible.
- **Innovation**, encouraging approaches that foster the development of new and efficient solutions for securing inertia.

5.3. Assessment of options to recover inertia securement costs

Table 5-4 outlines the summary of the advantages (+) and disadvantages (-) of the following selected options based on the criteria for assessing approaches to recover inertia securement costs:

1. Charging generators which do not provide inertia
2. Cost-recovery from broad group of network users
3. Utilizing existing balancing mechanisms

The table includes brief explanations for each rating, detailing how each cost-recovery approach meets or falls short of the criteria. Please note that this is the summary table. The full assessment table, which discusses all considerations in a more elaborate manner, can be found in the second Annex, in Table 7-1.

Table 5-4 Summary assessment table of the cost-recovery approaches vs criteria

Criteria	Impact	1. Charging generators without inertia	2. Cost-recovery from broad group of network users	3. Utilizing existing balancing charges
Cost-reflectiveness	+	+ (Some) who do not contribute to grid stability financially responsible for the associated costs	+ Reflects collective responsibility for system stability + Reduces the risk of bias in cost allocation	+ Ensures that cost recovery aligns with the established market structures and dynamics
	−	- Assumes the historical perspective that generators should be responsible for the provision of inertia.	- May not sufficiently reflect the specific contributions of individual network users to inertia requirements or provision of services	+ Current balancing charges might not be tailored to specific cost drivers of inertia + Not all MSs charge balancing costs the same way and this might risk exacerbating existing distortions
Transparency	+	+ Can be charged separately, increasing transparency	+ Reduces the complexity involved in individual cost assessments, leading to more straightforward reporting and documentation	+ Benefits from pre-established frameworks and reporting processes, and can therefore be transparent
	−	- Complicates the tariff design for generators, who have to account for it in investment and operational decisions	- Tariff methodology complex, making it potentially difficult to understand for network users if not clearly explained	- Complexity might hamper transparency and existing mechanisms might not be fully transparent about costs associated with inertia
Innovation	+	+ Strong incentive for generators to innovate, supply inertia, and avoid charges	+ Can spur innovation by creating a broad-based financial incentive for the development of new technologies, if specific users are exempted from + Gives room for innovative tariffication designs	n.a.
	−	- Only generators have an incentive to innovate	- Since the cost is spread out over many network users, there are no strong incentives to innovate	- Constrains the scope for significant or breakthrough innovations

5.3.1. Assessment of the policy options

Charging the specific **inertia costs only to generators that do not provide inertia** (first option) could be considered. The logic here is as follows: in the past, conventional power plants provided inertia at no additional remuneration. However, by transitioning from inertia-providing to inertia-less generators, the need for inertia and the associated costs have emerged. Therefore, it could be argued that it is cost-reflective to charge these costs to generators, who are at the root of the issue. This charge can be proportional to the inertia they displaced. However there might be a difficulty in implementing, as determining the correlation between these costs and the characteristics of generators is complex. It may also be challenging to align a generator's impact on inertia needs with the overall system's real-time requirements, as charging non-running plants could distort operational decisions and lead to suboptimal outcomes.

In any case, a main consideration is that the reasoning behind this cost allocation is not entirely sound. Historically, synchronous generators provided inertia as a byproduct of their normal operation, but this does not mean they should bear this responsibility in the future. Furthermore, this reasoning is further weakened by the fact that other network users also contribute to the decline of inertia, particularly through the replacement of synchronously connected loads with inverter-based ones. It can therefore be argued that this approach unfairly places a disproportionate burden on generators, among which renewable energy-based ones, which could hinder the achievement of renewable energy targets. Due to these concerns about non-discrimination, cost-reflectiveness and achievement of climate & energy targets this option is not deemed as appropriate.

Alternatively, there is the possibility of **utilizing existing balancing charges** (third option). This approach has the potential to leverage existing charging mechanisms (see Textbox 1 below), making it straightforward to implement. At first glance, inertia resembles existing balancing services like FCR, but with a shorter reaction time. Therefore, it seems logical that cost recovery should follow a similar approach for comparable services. However, this approach has two key drawbacks. The most significant is that if balancing capacity charges are not cost-reflective, incorporating inertia into the cost recovery mechanism could exacerbate the issue. Secondly, the factors influencing inertia-related costs do not necessarily align with those driving other balancing charges, necessitating different approaches to cost recovery. Therefore this approach does not seem adequate either.

The final approach to be considered involves **cost recovery from broad groups of network users** (second option). The rationale behind this is as follows: Since all network users benefit from grid stability, it is fair that the associated costs be distributed among them. This is by far the most flexible option, offering ample room for designing tariff structures. This can be implemented through both injection and offtake charges, as well as by charging for energy or capacity. This topic is further discussed in section 5.3.2. It can be applied either as a separate charge or by increasing an existing charge, similar to how other non-frequency ancillary services are recovered. This could be an appropriate approach, as it offers the greatest flexibility and, if well-designed, leads to the least amount of distortion.

Textbox 1 Recovery of balancing reserve and other system service costs in the EU

The **costs of procuring balancing reserves** in the EU are distributed among network users to reflect their contribution to system imbalances or their benefit from stable system operation. The allocation method varies across EU Member States, depending on the national framework and tariff design within each Member State. Options include **allocating costs partially or fully to the following network users**:

- Generators: Often linked to the capacity or type of generation.
- Consumers (or loads more generally): Usually through withdrawal tariffs to reflect their role in demand-side imbalances.
- Prosumers: Depending on their net withdrawal/injection behaviour, they may pay both generation and consumption-related charges.

- Suppliers.
- Balancing responsible parties (BRPs).

The balancing reserve costs can be recovered through the **following charges**:
- Transmission tariffs, integrated as a component of the broader network tariffs paid by network users
- Separate tariffs, specific balancing or system services tariffs, designed to ensure cost transparency
- Market-based charges, with allocation based on participation in balancing markets, e.g. imbalance settlement

Member States have different methods to recover these costs. [106] According to ACER, In most Member States (over two thirds of countries surveyed in its latest overview) costs for balancing reserves and other system services are recovered through use-of-network charges. In some cases, costs are recovered from e.g. suppliers, such as in Greece. It must also be noted that in several Member States, FCR or other services are not remunerated in the first place.

In the case of cost recovery through use-of-network charges, Member states can have exemptions, discounts or differentiation of unit tariff values or tariff basis between producers, which often depend on criteria such as the size of installation, connection voltage, or technology used. System service costs are furthermore usually recovered through withdrawal tariffs and are often presented as separate tariff elements to ensure transparency. For example in 8 Member States (and Norway) system services are recovered through separate tariffs or separate tariff elements in the use-of-network charges.

5.3.2. Cost recovery of inertia securement

Network charges can also be distributed between injection and offtake. In Europe, system costs are partly recovered from generators only in four Member States. In most other European countries, system costs are at present only recovered from grid off-takers. [107] In Australia, in the context of the National Electricity Amendment, AGL had proposed that the costs related to inertia services could be recovered based on a 50/50 split between consumers and generators.[108]

A potential drawback of charging network tariffs entirely or partially to generators is the risk of market distortions if this approach is not harmonized across Member States. For instance, if generators are charged in one country but not in another, the ones located in the latter gain a competitive advantage. For this reason, Commission Regulation (EU) No 838/2010 sets limits to the transmission tariffs for producers. Consequently, most Member States do not impose such charges on generators.

A combination of injection and offtake charges is likely the most cost-reflective approach, though it may involve a more complex implementation then simply using offtake charges. This report recognizes that each countries specific circumstances differ and argues for leaving this decision up to each countries authority that decides the network tariffication (this is mostly but not exclusively the NRA).

Nonetheless, we argue that if generators are to be charged to finance inertia needs, efforts should be made to ensure harmonization across Member States. Moreover, if injection charges are chosen, lump sum and/or power-based charges should be used to recover inertia securement costs, while energy-based charges are discouraged.

[106] ACER (2025) Getting the signals right: Electricity network tariff methodologies in Europe. ACER report on network tariff practices
[107] ACER (2025) Getting the signals right: Electricity network tariff methodologies in Europe. ACER report on network tariff practices
[108] Final-version-for-publication-ERC0208-Final-Determination.pdf

5.3.3. Need for harmonisation in tariffication design

As mentioned in Section 5.1, the cost of securing inertia remains relatively low compared to balancing costs. As a result, the risk of significant competition distortion is limited, given the relatively minor costs involved. This is particularly the case if costs are recovered from a wider range of network users.

Hence, **we currently find no compelling reason to impose strict harmonization requirements for the recovery of inertia securement costs across EU Member States.** As with other tariffs, the decision should be made by the NRA, taking into account the specific circumstances of each region and any EU-level guidelines, even though we recommend for NRAs defining methodologies recovering inertia costs through a dedicated charge or a dedicated element within use-of-network charges.

However, in the Affordable Energy Action Plan, the Commission stated that it would introduce tariff structure guidelines and, if necessary, propose legislation to make them legally binding[109]. As part of this work, the Commission could also provide guidance on how to recover inertia costs. However, non-binding recommendations may be issued for NRAs to implement specific charges for recovering inertia costs (and possibly other non-balancing ancillary services, such as voltage control), clearly outlining the cost drivers and how costs should be allocated across voltage levels and network user categories, as well as introducing transparency requirements.

If a decision is made to have generators bear a significant share of the cost of procuring inertia, whether through higher injection charges, a separate fee for not providing inertia, or another mechanism, we recommend EU-wide harmonization of these charges to avoid distortionary effects on energy markets, in concordance with EU commission regulation 838/210.[110]

[109] European Commission. (2025). *Action Plan for Affordable Energy*. COM (2025) 79 final.
[110] European Commission. Commission Regulation (EU) No 838/2010

6. Annex – Detailed assessment of options to secure inertia

Table 6-1 outlines all the advantages ⊕, neutral characteristics ● and disadvantages ⊖ of the following selected options based on the criteria for assessing approaches to secure system inertia:

4. Market-based dedicated procurement mechanism
5. TSOs directly investing in and operating dedicated assets
6. Revising connection requirements for generators and storage operators.

The table presents the assessment of the different options, detailing how each options presents advantages and disadvantages under each criterion.

Table 6-1 Assessment table of inertia securement approaches vs criteria

Criteria	1. Dedicated procurement mechanism/market based approach	2. TSOs directly investing in and operating assets	3. Revising connection requirements
Complexity	(+) The market-based approach allows for a variety of procurement strategies, such as auctions, which can be tailored to meet both short-term and long-term inertia needs ● The level of complexity depends on whether inertia is procured through long-term contracts or a closer to real-time market mechanism (−) Implementing requires significant coordination between various stakeholders, including TSOs, DSOs and market participants. Transaction costs will be higher compared to the other alternative approaches Requires well-defined inertia products, which can be complex and entail design choices between e.g. speed of inertial response and eligible technologies Enabling cross-border participation of inertia service providers can be complex, if part of the market design Combination with procurement of other ancillary services and congestion management can be very complex Procurement volumes might not justify establishment of a market-based process	(+) Process benefits from centralized control, clear responsibility for inertia provision and oversight (also by the NRA). This reduces uncertainty and the need for extensive coordination between multiple stakeholders Decisions can be integrated into network development plan processes Faster deployment possible in critical areas where participation in market mechanism would be uncertain ● The complexity of scaling this approach can vary. While TSOs have the expertise and authority to manage inertia resources, expanding the deployment of assets across larger or more complex grids might require additional planning and resources (−) This approach can complicate coordination and cost allocation with other TSOs, especially in regions with interconnected grids Requires TSOs to take additional operational responsibilities	(+) Revising requirements allows for a standardized approach across various network user categories, which can simplify the overall framework for securing inertia Decentralized solution that embeds inertia within the evolving generation mix ● Implementing new requirements necessitates significant coordination among various stakeholders. While this effort can be substantial initially, it can lead to a more streamlined and efficient process once all requirements are in place (−) Implementing uniform requirements across different regions or synchronous areas may pose challenges due to varying grid conditions, existing infrastructure and regulatory environments Revising requirements involves coordination across multiple entities, including NRAs, TSOs, DSOs, producers and consumers, across the EU and beyond. Increases the regulatory burden for enforcing compliance Can deter investment if requirements impose significant costs on project developers and equipment manufacturers May face resistance from existing asset owners if applied retroactively.
Economic efficiency	(+) Promotes innovation and cost-efficiency among service providers by leveraging competitive processes Ensure that inertia services are provided by the most efficient and cost-effective market participants Can allow for cross-border participation of inertia service providers	(+) TSOs can make highly tailored investments in inertia-providing assets, such as synchronous condensers or specialized generators. Additionally, costs are generally predictable and can be planned over long periods TSO-owned 'value stacking': assets can simultaneously provide other services such as black start capabilities or short-circuit power which would be needed to be provided by TSOs anyway	(+) The updated requirements can create additional incentives for network users to invest in technologies or practices that enhance grid stability Could reduce long-term system costs by making inertia an inherent feature of future generation and storage. Avoids direct procurement costs by embedding inertia provision into new investments

Criteria	1. Dedicated procurement mechanism/market based approach	2. TSOs directly investing in and operating assets	3. Revising connection requirements
	Can be employed to procure simultaneously not only inertia but also other ancillary services such as voltage control and congestion management Enables price discovery for the provision of inertia services Procured volumes can be adjusted according to actual inertia needs (in case short-term products are used), minimising procured inertia in moments where there is sufficient inertia in the system due to e.g. spot and balancing markets cleared orders Can more easily allow for the use of existing assets, including through repurposing of soon-to-be decommissioned ones such as nuclear or fossil thermal power plants The effectiveness of the market-based approach largely depends on the liquidity and maturity of the market and the predictability of demand Providers might prioritize short-term gains over long-term stability, potentially leading to underinvestment in assets with required inertia service provision capabilities Can lead to high procurement costs in oligopolistic markets if mechanism is not well designed	TSOs can present lower cost of capital compared to returns demanded from market participants Demands substantial investments from TSOs, which can strain financial resources. This includes both upfront costs, as well as ongoing operational and maintenance expenses. Does not allow to leverage market-owned assets, nor can TSO assets be employed for market purposes Might lead to over-dimensioning of inertia needs at the regional/EU level as cross-border sharing of inertial resources can be more difficult TSO-owned assets provide inertia at all times, even when market assets dispatched in spot and balancing markets might already provide sufficient inertia Can reduce visibility on the costs for securing inertia May lead to inefficient over-procurement if system needs to be changed in the future	This approach involves regulatory costs and administrative efforts. These are necessary for implementation but are generally considered as part of the overall economic landscape If the revised requirements are not well-designed or if they fail to account for regional differences in infrastructure and operational practices, they could lead to inefficiencies Could discourage investment in certain technologies, if requirements are too rigid or costly Requirements will typically apply only to new and not already-connected network users, therefore limiting effectiveness
Technical adequacy	Allows for the procurement of inertia services that are specifically tailored to the system's technical needs. It might allow also for the exchange of inertial resources to some extent across control areas Requires the consideration of a locational component in the mechanism design, not only at bidding zone level but even a finer granularity	TSOs can deploy inertia-providing assets in strategic locations, ensuring sufficient inertia in all control areas and avoiding reliance on market dynamics Relying solely on TSO-provided assets for inertia might limit the diversity of technical solutions available to the grid.	By mandating that TSOs, generators and other users meet specific technical criteria, the grid's ability to maintain stable will be improved Can address other technical aspects such as fault ride-through capabilities and curtailment of network uses which are complementary to the other options Ensures a growing base of inertia-providing assets over time, aligning with the energy transition. Decentralized provision can improve system-wide inertia distribution

Criteria	1. Dedicated procurement mechanism/market based approach	2. TSOs directly investing in and operating assets	3. Revising connection requirements
	Market-provided assets might comprise mainly grid-forming converter-based assets, but these are capable of providing sufficiently fast responses Might not fully meet the inertia needs in all scenarios (or only at high cost) in case of an inadequately designed mechanism, particularly in less competitive or isolated regions, requiring the deployment of TSO-owned assets to make up for the inertia gap Some assets equipped with grid-forming converters might be best suited to respond to over frequency rather than underfrequency events, if they do not have additional storage capability on the DC side Short-term procurement may not always align with long-term system stability needs	May result in excess inertia in some regions and shortages in others if system needs evolve differently than anticipated	There will be a risk of technical over-specification, imposing unnecessary burdens on network users. Lastly, different network users have varying technical capabilities making a one-size-fits-all approach difficult to specify. Uncertainty on much inertia new assets will provide in practice
Innovation	The competitive nature of a market-based approach encourages participants to innovate. This could lead to improvements particularly to grid-forming converters for new assets and upgrading existing BESS and RES plants Market participants may be focused on developing solutions that meet immediate needs or also consider long-term innovation The emphasis on short-term improvements might limit investments in more ambitious, long-term innovations. Additionally, integrating inertia into existing platforms can be time-consuming potentially delaying the deployment of this approach	While TSOs might not inherently drive innovation through competition, they can still stimulate strategic innovation by partnering with technology providers and allow for pilot projects in advanced infrastructure TSOs are generally risk-averse, prioritizing stability and reliability The lack of market dynamics might lead to higher long-term costs, as there is less pressure to find cost-effective or innovative technologies. Additionally, the conservative approach of the TSO can hinder the adoption of innovative technologies that could enhance grid stability or cost efficiency. This can apply also to high-inertia synchronous condensers, which have a lower TRL	This approach can drive innovation by setting ambitious standards that push network users to develop and adopt new technologies and practices While revising requirements can promote innovation, the pace and scope of innovation are often incremental rather than transformative New requirements may reduce creativity and limit the ability of network users to explore unconventional or novel solutions. Additionally, there may be a delay in the implementation of new requirements and the actual adoption of innovative technologies, because regulatory changes might not immediately align with technological advancements. Lastly, the drive for innovation induced by new requirements can sometimes lead to higher costs for network users., which can result in financial challenges

7. Annex – Detailed assessment of options to recover costs of securing inertia

Table 7-1 outlines all the advantages ⊕, neutral characteristics ● and disadvantages ⊖ of the following selected options based on the criteria for assessing approaches to recover inertia securement costs:

1. Market-based dedicated procurement mechanism
2. TSOs directly investing in and operating dedicated assets
3. Revising connection requirements for generators and storage operators.

The table presents the assessment of the different options, detailing how each options presents advantages and disadvantages under each criterion.

Table 7-1 Assessment table of the cost-recovery approaches vs criteria

Criteria	1. Charging generators without inertia	2. Cost-recovery from broad group of network users	3. Utilizing existing balancing charges
Cost-reflectiveness	⊕ Charging generators which do not provide inertia ensures that (some of) those who do not contribute to grid stability are financially responsible for the costs associated with their lack of contribution. ● The effectiveness of this approach in reflecting costs depends on how accurately the charges are calculated and how well they align with the actual cost incurred to address the lack of inertia. ⊖ This reflects a historical perspective that generators are responsible for providing or paying for inertia, but all network users benefit from inertia. Moreover, not only generators but also consumers are able to deliver inertia. In a future with 100% renewables, this would mean that the entire cost falls on renewable generators, even though they are not solely responsible for the need for inertia.	⊕ This approach distributes the costs of maintaining grid stability across a wide range of consumers and generators, reflecting the collective responsibility for system stability. Furthermore, charging broad groups rather than individual entities reduces the risk of bias in cost allocation. ● The cost-reflectiveness of this approach is influenced by how well the broad allocation reflects the actual contributions and impacts of different groups on grid stability. ⊖ This approach may not sufficiently reflect the specific contributions of individual consumers or generators to inertia requirements or provision of services. Network users' roles in driving inertia needs will not be time-coincident with overall system inertia needs, and will furthermore vary per user category	⊕ Utilizing existing balancing charges ensures that cost recovery aligns with the established market structures and dynamics. Furthermore, existing balancing mechanisms are designed to address specific needs in the grid and are designed to be cost-reflective, at least for balancing costs. ● This approach integrates cost recovery into an established processes, which can provide straightforward means of allocating costs. However, the extent to which charges are reflective depends on how well the existing mechanisms align with the broader impact on grid stability. ⊖ Existing balancing charges may not be fully tailored to address the specific costs associated with securing inertia. Additionally, if the current balancing mechanisms have inherent biases, using them for cost recovery could reinforce this.. Reserve balancing costs are charged differently across the Member States, and might lead to more distortions between network users if inertia-securement costs are included.
Transparency	⊕ Inertia can now be charged separately to generators from other charges, clearly presenting information on who should be charged and by how much ● While the concept of charging generators without inertia is straightforward, the actual	⊕ The broad allocation approach reduces the complexity involved in individual cost assessments, leading to more straightforward reporting and documentation. ● Effective transparency requires clear explanations of the methodology used to	⊕ Utilizing existing balancing mechanisms benefits from pre-established frameworks and reporting processes. Stakeholders already have access to consistent and regular updates on the operation of these mechanisms.

	transparency of the approach depends on how well the charges and their underlying calculations are communicated to the stakeholders. This option increases the complexity of the tariff design, who have to account for it in investment and operational decisions	determine and apply charges to broad groups. The overall transparency may be limited if the rationale behind the cost allocation is not clearly explained. The tariff structure might be complex, making it more difficult for network users to understand. It is also possible that the charge for inertia may not be separate from other network charges, resulting in reduced transparency.	The level of transparency depends on how well the existing balancing mechanisms are designed and implemented. Even though existing mechanisms provide a framework, the complexity of these processes can sometime obscure detailed transparency and existing mechanisms might not be fully transparent about the specific costs associated with inertia.
Innovation	Charging generators without inertia can drive innovation by creating financial incentives for generators to invest in inertia-providing technologies, such as grid-forming converters. There are also opportunities for innovation in tariff design, such as time-based differentiation. Charging generators could hinder innovation by slowing the deployment of renewables, as it introduces an additional cost, making them less competitive compared to conventional power plants. While it offers strong incentives for generators, this approach fails to provide incentives for other grid users..	This approach can spur innovation by creating a broad-based financial incentive for the development of new technologies or strategies to enhance grid stability. This approach gives room for innovative new tariffication designs. While the approach itself does not directly target innovation, it creates an environment where network users might seek innovative solutions as a way to reduce their financial burdens. Because the costs are spread across many users, the individual impact may be small resulting in not providing strong, direct incentives for innovation.	Utilizing existing balancing mechanisms can promote innovation within established frameworks. While this approach can foster innovation within existing structures, it may not directly encourage radical or disruptive changes, either in tariff design or technology. Existing balancing mechanisms might constrain the scope for significant or breakthrough innovations.

8. Annex - Literature review

8.1. Introduction to the literature review

A literature review was carried out to provide an overview of the main drivers of inertia needs, the current challenges and their expected evolution as the European power system further decarbonises (which implies a higher share of variable power generation sources and a lower share of rotating machines, investments in grids, etc.), the potential solutions and approaches to secure the required level of inertia (technological, regulatory, ...) and the associated costs.

The publications reviewed were published in recent years, except a few in 2018 and one in 2016. They cover several geographical contexts (EU, Great Britain, Ireland, Texas, Australia, etc.). Numerous other studies have been used as sources for specific sections of this report and are indicated with footnotes where relevant.

The lessons learnt from the documents analysed can be found in the relevant sections of the report. This section provides a complementary analysis, detailed by publication, for some of the most relevant studies.

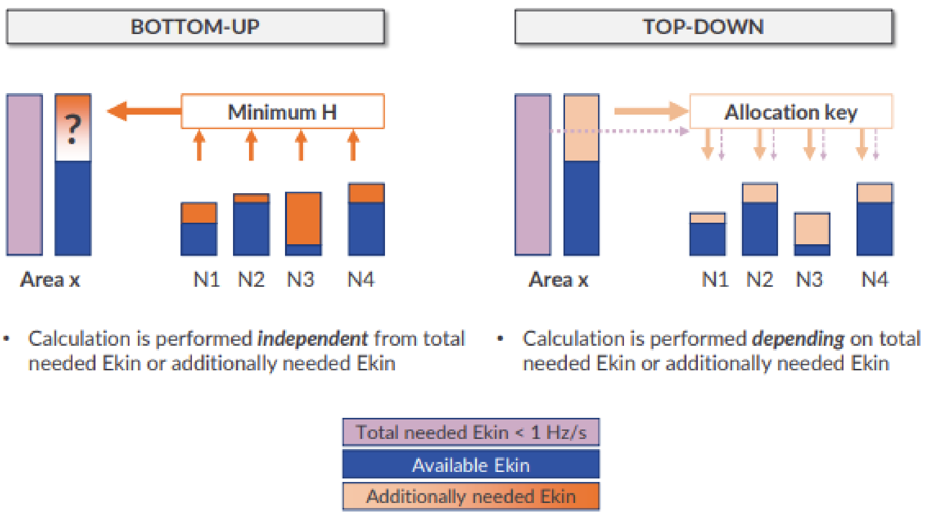
8.2. Review per publication

8.2.1. ENTSO-E, "Project Inertia – Phase II: Recovering power system resilience in case of system splits for a future-ready decarbonised system: Supporting technical report", 2025

<table>
<tr><th colspan="3"><u>Title:</u> Project Inertia – Phase II: Recovering power system resilience in case of system splits for a future-ready decarbonised system: Supporting technical report</th></tr>
<tr><td><u>Institution:</u> ENTSO-E</td><td colspan="2"><u>Authors:</u> Project Inertia group</td></tr>
<tr><td><u>Date Published:</u> 10 January 2025</td><td><u>Pages:</u> 26</td><td><u>Document Type:</u> Technical Report</td></tr>
<tr><td colspan="2"><u>Keywords:</u> Kinetic energy allocation, resilience levels</td><td><u>Link:</u>
Position paper:
https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/Publications/Position%20papers%20and%20reports/2025/250123_Project_Inertia_II_Position_paper_Recovering_power_system_resilience_in_case_of_system_splits_for_a_future-ready_decarbonised_system.pdf
Technical report:
https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/SOC%20documents/241220_Project_Inertia_II_milestone_3_support_technical_report_proofread_tracked_reviewed.pdf</td></tr>
<tr><td colspan="3">Abstract: Results from a previous ENTSO-E study showed that the number of system splits originating cases where both split subsystems exceed the 1 Hz/s operational threshold (called Global Severe Splits) significantly increases from the 2030 to 2040 scenarios. This position paper and supporting technical report propose decision-making information (based on new modelling work) and a roadmap to the foundational measures as part of a</td></tr>
</table>

<table>
<tr><td colspan="3">step-by-step, non-regret approach to deliver secure and efficient operation for a future-ready decarbonised system.</td></tr>
<tr><td><u>Geographical area:</u> Continental Europe</td><td><u>Size:</u> Very large</td><td><u>Interconnection level:</u> Highly interconnected</td></tr>
<tr><td colspan="2">Type of solution considered</td><td></td></tr>
<tr><td colspan="3">Analysis of the publication according to proposed focus areas</td></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">The evolution of the generation mix in 2030 generates reduced levels of inertia, meaning a reduction of the system's resilience in case of system splits. It is therefore necessary to define a minimum level of inertia for CE. However, allocation methods to reduce the occurrence of Global System Splits (GSS) should not lead to an over dimensioned system.

Beyond just estimating available inertia, additional operational data can enhance time-domain analysis to better understand the system's response to disturbances. The main challenge is then to accurately incorporate key factors into the simplified swing equation model, including synchronous rotating masses, Grid Forming devices, FCR deployment dynamics, and various fast control reserves like synthetic inertia and emergency reserves.</td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">System splits are the main drivers of inertia needs since RoCoFs above 1 Hz/s are only observed during such events, which largely exceed the reference incident of 3,000 MW with high power imbalances and low system inertia.</td></tr>
<tr><td>Considerations related to national needs due to potential splits</td><td colspan="2">



The allocation of the additional kinetic energy is conducted in this study through a bottom-top approach, meaning that it begins with defining a minimum inertia constant that each node should provide. The additional kinetic energy needed in each node to meet this requirement is then calculated. Then the system performance is calculated for this allocation for all identified global severe split cases to assess its efficiency. It must be noted that since country internal splits are possible, the equal distribution of kinetic energy within countries is also advisable. The amounts of additional kinetic energy required from each country could be made of a fixed allocation (typically suited for assets like Synchronous Condensers) or a variable allocation. The variable allocation would require highly flexible and liquid market procurement methods where amounts are successfully procured according to forecasts of available/needed inertia levels. A minimum nodal inertia constant requirement of 2 sMW/MVA or higher shows a great performance (~98% GSS are</td></tr>
</table>

	satisfied) when only one side of the split must be satisfied. Using a 100% percentile as a fixed value for each node is not recommended since this could (significantly) exceed the existing kinetic energy levels at the SA level. According to the study, on a first short/medium-term target, all countries shall initiate actions as soon as possible to gradually ensure a minimum inertia constant of 2 sMW/MVA for 50% of the year. This would require an additional kinetic energy at the synchronous area level of 73 GW.s in the NT2030 scenario ENTSO-E also recommend as a long-term target that all countries should ensure a minimum inertia constant of 2 sMW/MVA for 90% of the year. This would require an additional kinetic energy at the synchronous area level of 267 GW.s in the NT2030 scenario. At the same time this implementation would not exceed the 2019 total European kinetic energy levels and would allow to prevent more splits where one islands experiences a RoCoF above 1 Hz/s. It must however be highlighted that these propositions mostly aim at avoiding GSS, other split situations where one subsystem could experience a blackout would remain even following the long-term target. These values must be considered as an important resilience reference but not as a definitive metric. Future reassessments should refine inertia allocation by considering factors like system balance and load, ensuring efficient kinetic energy distribution across CE SA.
Evolution of inertia needs (based on analysis of underlying drivers)	There is a need for permanent monitoring and regular updating of the system's minimum kinetic energy needs (for example every two years using the up-to-date TYNDP). To correctly assess the need for inertia, key factors would also need to be incorporated in the calculations to investigate the real system's response to disturbances, such as: - The effect of rotating synchronously connected masses (effect of load) - Effect of Grid Forming devices Additional assumptions regarding the influence of fast control reserves such as synthetic inertia
Proposition of solutions to secure inertia	According to this study, it would be up to the TSOs to choose the most appropriate set of solutions to secure the minimal inertia level. The study highlights the fact that long-term market incentives and needs visibility can encourage investment in PPM (Power Park Modules) capabilities. These capabilities will be necessary to meet the long-term kinetic energy targets and ENTSO-E insists that any device that can provide inertia (PPMs, STATCOMs and SCs connected for system strength/voltage needs) should provide inertia. ENTSO-E stresses that "*Project Inertia's goal is to enable RES, rather than limiting them in any way. The methodology does not propose, under any circumstances, decisions on RES limitation. The proposed solution will not affect RES penetration or market.*"
Technologies that are foreseen to provide inertia	Classical synchronous machines Grid-Forming Devices (GFM): to provide an inertial response PPM (Power Park Modules) should be equipped with an energy buffer, mainly created through supercapacitors or batteries connected to the DC bus of the converters.
Cost estimations	*No cost estimation provided*
Reviewer's comment	

8.2.2. ENTSO-E, “Project Inertia – Phase II: Updated frequency stability analysis in long term scenarios, relevant solutions and mitigation measures”, 2023

<table>
<tr><th colspan="3"><u>Title:</u> Project Inertia – Phase II: Updated frequency stability analysis in long term scenarios, relevant solutions and mitigation measures</th></tr>
<tr><td><u>Institution:</u> ENTSO-E</td><td colspan="2"><u>Authors:</u> Project Inertia group</td></tr>
<tr><td><u>Date Published:</u> November 2023</td><td><u>Pages:</u> 33</td><td><u>Document Type:</u> Report</td></tr>
<tr><td colspan="2"><u>Keywords:</u> System split, asynchronous electrical islands, RoCoF</td><td><u>Link:</u> https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/sdc-documents/231108_Project_Inertia_Phase_II_First_Report_FOR_PUBLICATION_clean.pdf</td></tr>
<tr><td colspan="3"><u>Abstract:</u> The report first analyses historical system split events in Europe. Then it performs analytical calculations to study numerous possible combinations of system split cases in the CE SA and the associated RoCoF at the centre of inertia in 2030 and 2040 scenarios. This allows to assess whether the subsystems would be able to cope the RoCoF resulting from the initial conditions (power imbalance and subsystem inertia). A significant decrease in system resilience is observed. In addition to the risk of a blackout in the whole SA following a system split, the study evaluated if a total blackout could occur due to frequencies outside the range 47.5–51.5Hz, even if the initial RoCoF is smaller than 1 Hz/s. According to the study results, most of the total blackouts are due to high RoCoF (RR) and not due to frequency excursions beyond the limits.</td></tr>
<tr><th colspan="3">Characteristics of the power system involved</th></tr>
<tr><td><u>Geographical area:</u> Europe</td><td><u>Size:</u> Very large</td><td><u>Interconnection level:</u> Highly interconnected</td></tr>
<tr><th colspan="2">Type of solution considered</th><td>Technology</td></tr>
<tr><th colspan="3">Analysis of the publication according to proposed focus areas</th></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">Since a high initial RoCoF reduces the available time to deploy the actions necessary to prevent high frequency imbalances, it is necessary to keep the initial RoCoF values after an incident below 1 Hz/s. This requires a minimum level of inertia in addition to reliable system defences.

The study considers cases of system splits in Continental Europe and determines the resulting RoCoF in each of the two resulting separated areas.

The results presented in this study show that system splits for which at least one island exceed the RoCoF threshold of 1 Hz/s and splits for which both islands exceed this threshold are identified in the Continental Europe area in a large number and with an increase from 2030 to 2040.</td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">The study considers that the main driver of inertia needs is the case of system splits. The inertia in the system must allow the RoCoF in each of the created islands to stay below 1 Hz/s (in absolute value) and the frequency to stay in the range 47.5-51.5 Hz after a system split to prevent a blackout. To estimate the RoCoF, ENTSO-E calculate the RoCoF at the initial time of the incident and at the centre of inertia.

The RoCoF at the centre of inertia after a system split is the following:</td></tr>
</table>

	$$\frac{df}{dt} = \frac{f_0}{2}\frac{\Delta P}{E_k}$$ Meaning the minimum kinetic energy E_k required to keep the RoCoF below 1 Hz/s can be computed from the imbalance ΔP with the following formula $\frac{f_0}{2}\|\Delta P\|$. The **imbalance ($\Delta P$) following a system split can be computed from the hourly exchange data** (based on TYNDP22 in this study). The kinetic energy E_k is computed from the hourly generation mix and assumptions on the inertia constant by fuel type in addition to the assumption on the loading factor of generating units. The analysis of total blackout focuses on the Rate of Change of Frequency (RoCoF) and key kinetic energy indicators. Specifically, it examines the additional kinetic energy required per subsystem (split area) to keep RoCoF below 1 Hz/s. It can be noted that **most of the total blackouts calculated in this study are due to high RoCoF and not to frequency thresholds issues**.
Considerations related to national needs due to potential splits	
Evolution of inertia needs (based on analysis of underlying drivers)	The scenarios with greater occurrences of total blackouts are DE2040 and GA2040. These increased risks are driven by increased power flows, increased levels of renewables and by the grid being operated closer to its limits, meaning that errors can **more easily lead to large incidents**. To avoid all Global Severe Splits for the scenario NT2030 (Global Severe splits = scenarios where the initial RoCoF exceeds 1 Hz/s in both resulting subsystems), **the system would need 445 GWs of additional kinetic energy** (it corresponds to 255 synchronous condensers of 250 MVA and H=7 MWs/MVA).
Proposition of solutions to secure inertia	To keep inertia above a certain limit a **market-based procurement of inertial response** should be considered, based on new markets (inertia certificates for instance) or inspired by already existing markets (FCR). Market-based procurement of inertial response, such as through inertia certificates or similar mechanisms, would require careful design and regulatory frameworks. Key aspects include product design (e.g., bid size, activation triggers, and settlement rules), provider prequalification, and effective monitoring. Establishing such markets could be challenging, especially for cross-border systems, as TSOs would coordinate technical requirements, central platforms, and harmonized rules. While markets allow for continuous procurement and monitoring, poor design or low liquidity could lead to inefficiencies and operational risks. In addition to the provision of inertia, additional measures are required to enhance withstand capabilities and support frequency containment. **The study insists on the fact that these additional measures will upgrade the stability of the system only if the inertia already assures a system for which RoCoF stays below 1 Hz/s**. According to this study the need for inertia should be reviewed every two years using the updated TYNDP scenario and **every country will need to ensure an agreed minimum level of inertia**. Additionally, a **methodology to estimate online inertia at all times should be developed and agreed by all TSOs of the Continental Europe synchronous area**.

Technologies that are foreseen to provide inertia	➢ All existing synchronous generators are providing inertia as well as some loads ➢ Grid forming capable grid users (e.g. Power Park Modules [PPMs] or storage with inertial response) ➢ Grid forming capable STATCOMs ➢ Synchronous condensers The study recommends a fast deployment of synchronous condensers and STATCOMs with storage. PPMs with GFM capability and storages are not expected to be widely installed before 2028 grid code revision). These solutions also bring added benefits to system stability (voltage control and short-circuit power). PPMs capable of grid forming and storage should also be deployed as soon as possible.
Cost estimations	*No cost estimation provided*
Reviewer's comment	
Based on TYNDP2022 NT 2030 scenario, which shows significant differences with scenario NT+ of TYNDP2024, such as EU27 installed capacity of solar (from 350 to 650 GW) and wind (from 350 to 470 GW, both onshore & offshore), or power demand (from about 3000 to 3450 TWh). The study does not cover: - Definition of inertia product (especially duration. e.g. 500 ms), and thus of potential other products (overall mixing Inertia and FFR) - The exchangeability/fungibility of inertia (can the inertia be provided from any location on the grid) - The measurability: is a unique measure of the global continental grid inertia enough ? - Hurdles to GFM deployment. - The consistency of the dimensioning contingency for inertia and FCR (should they be equal or could it be smaller for FCR than for inertia?) - Justification of the 1 Hz/s limit	

8.2.3. ENTSO-E, Inertia and Rate of Change of Frequency (RoCoF), 2020

Inertia and Rate of Change of Frequency (RoCoF)		
Institution: ENTSO-E	Authors: TF Inertia of SPD	
Date Published: 16 December 2020	Pages: 46	Document Type: Report
Keywords: System splits, options to deal with a lack of inertia, grid-forming		Link: https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/Inertia%20and%20RoCoF_v17_clean.pdf
Abstract: This report focuses on the impact of a future decrease of system inertia, with the development of inverter-based generation (solar and wind), which reduces the share of generation from power plants with rotating masses. The behaviour of the Continental European power system under lower inertia is studied and recommendations are proposed. The report provides theoretical considerations on the assessment of system inertia and presents model calculations results.		

<table>
<tr><td>Geographical area: Europe</td><td>Size: Very large</td><td>Interconnection level: High</td></tr>
<tr><td colspan="2">Type of solution considered</td><td>Technology</td></tr>
<tr><td colspan="3">Analysis of the publication according to proposed focus areas</td></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">With the transition towards a carbon neutral energy mix, large amounts of renewables will be installed. As they are nowadays equipped with a Grid Following Mode (GFL) control scheme, they do not contribute to the system inertia. They are also often placed far from load centres, which results in much larger transits across the transmission system. Large transits across the transmission system increase the risk of system splits significantly. In case of system splits, a larger transit across the network is transformed into larger imbalances in the separated islands and the inertia in the separated islands is decreasing. One of the most critical factors for potential high RoCoF is a too high transit power flow over long distances.

High RoCoFs can lead to the following critical issues: 1/unintentional tripping of relays (due to inaccuracies in the measurement of the frequency and/or RoCoF), 2/ over-extensive load shedding, and 3/ frequency collapse before the relays have time to trip. Since there is very little time for the dedicated automated schemes to reinstall the equilibrium between consumption and generation with high RoCoFs, the remaining islands are more prone to a blackout. The report provides historical examples of transients with RoCoF higher than 1 Hz/s that ended with fast grid collapse due to the incapacity of regulations and defence systems to trigger in time. The limit of 1 Hz/s is related to the minimum time to measure the phenomena in a stable and secure way and react by opening the circuit breakers of loads or generation. It seems that the current frequency measurement technologies does not guarantee correct operation of protection equipment in the presence of this kind of transients.

Systems with a high share of inverter connected generation (i.e. low share of synchronous machines) also show a decrease in short-circuit power. This short-circuit power reduction will increase the impedance seen by generators, which affects the stability of the system and worsens the impact of voltage dips (deeper dips and wider influence perimeter). A worsening of the voltage recovery may also have for consequence a cascading disconnection of other generators nearby the incident. The actual protection scheme relies on equipment configured with thresholds defined for a system with high capability of short-circuit current injection and voltage support. With the decrease of this capability this scheme will need to be continuously evaluated and at a certain moment adapted.</td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">To define the minimum inertia limit, it is necessary to fix the maximum RoCoF value by considering:

• Stress on electrical machines of the system

• Loss of synchronism of large areas of system

• Potential split of the grid

• The time needed to measure the frequency and trip the protection equipment (including circuit breakers)</td></tr>
<tr><td>Considerations related to national needs due to potential splits</td><td colspan="2">No national consideration relevant to this study.</td></tr>
</table>

Evolution of inertia needs (based on analysis of underlying drivers)	The impact of system splits, has not yet been investigated so far and should be in the focus of further analyses, since a system split results in a larger frequency excursion and triggers additional supporting measures for stabilizing the frequency
Proposition of solutions to secure inertia	ENTSO-E lists 4 ways of dealing with a deficit of inertia and analyses their consequences. ➢ **“Taking the risk”** means not taking any actions. This is applicable for out-of-range contingencies and when only small parts of the system are affected (local blackout can be followed by a fast re-energisation under the support from a stable backbone of the main grid). Here, the costs for preventing a blackout are unreasonably high compared to the damage that a blackout may cause. ➢ **“Reducing transit”** refers to a reduction of transits across the AC-grid to keep imbalances within controllable limits after a system split (HVDC are not disconnected by system splits). Since high transit power flow over long distances is one the most critical factors for potential high RoCoF, reducing transits is an effective way to avoid instabilities. However, this approach should only be used when other means are not available or more expensive because it would inhibit the transition towards a carbon free energy mix and have significant effect on the market. ➢ **“Speeding up the control”** refers to the speed of means designed to reduce the nadir (LFSM-O, LFSM-U, load and generation shedding), which have an impact on the averaged RoCoF over a given time window (commonly 500 ms). **These can only be implemented in long-term via network codes** and find their limit for control in the first 100 ms (where real inertia is needed) or when there is not enough time to measure frequency and react. **The more of this potential can be tapped, the higher is the value of the maximum admissible RoCoF.** This option is relatively low-cost as it optimizes technical capabilities of technologies and schemes (under condition of sufficient operating experience). ➢ **“Increasing of system inertia”** with TSO measures (installation of synchronous condensers, STATCOMs with storage) or network codes (grid forming for inverter-based generation, storage and HVDC). Grid-forming is not yet state-of-the-art. It is the option for system split scenarios leading to islands of significant size, where a fast re-energization after a blackout is not possible. If grid forming control schemes are applied on inverter-based generation or other inverter-based devices, the number of devices that needs to be installed for the sole purpose of increasing the system inertia can be reduced. It should be investigated which share of the required inertia can pragmatically be provided by devices with grid forming capabilities, and which one by dedicated network-based assets. Also, this technical challenge has to be sufficiently investigated and experienced on field. A concept for dealing with system splits should be developed, which implies identifying the most likely splits as well as looking deeper into the control schemes (system protection schemes) that are designed for stabilizing the resulting islands. Success factors for mitigating system splits in future networks: 1. Speed up the control as fast as possible. This is resulting in a high admissible maximum RoCoF. 2. Roll out grid forming capabilities on inverter-based devices in order to reduce investments in devices that are only dedicated to deliver inertia. 3. Install network-based assets that

	provide inertia. 4. Make sure in real time operation that inertia and devices with grid forming capabilities are evenly distributed across the whole system in order to avoid high local RoCoF values (inertia must-run).
Technologies that are foreseen to provide inertia	Renewables connected to the grid usually involve power electronics which follow the voltage wave of the network to inject active power (grid following converters). This means that such RES cannot provide natural frequency control, but this could be obtained with grid forming. Grid forming technologies are nowadays extensively studied and tested, and they seem to be a promising technological advance in medium-term. To provide a downward reserve, the control would need to increase the power output, thus would need to be able to produce more (have an energy storage of a few seconds). To provide upward reserves, the control would need to decrease, thus reduce power, spill power, or store the excess power in a storage. A synchronous machine is able to inject around 5 times its nominal current almost instantaneously when a voltage dip happens in the network nearby. This is a reactive power injection that helps the system recovering the voltage and, therefore, improves its transient stability condition. Taking into account that the current output is limited to the nominal rate of the power electronics of the converters (usually only slightly bigger than 1 pu), their response in terms of reactive power injection when voltage dips happen is limited (and it is, also, delayed by the needed control schemes). New technologies of PPMs (Power Park Modules) are able to provide static voltage control under similar conditions as a synchronous generator. Power electronics with grid forming controlled inverters can bring significant voltage strength to the system, but only limited short-circuit current. Synchronous condensers may bring both short-circuit current capability and inertia to the system. The study provides two examples of the “speeding up the control approach”: ➢ **“Synthetic inertia” from wind generators** to provide under-frequency response without permanent curtailment. The study cites demonstrators in Alberta, initiatives in Ireland and Hydro-Québec. Wind generators have this capability since 2015 in Québec, which helps reduce the nadir and but due to the need to restore the pre-rotating speed of the blades, it causes a 2nd nadir and delayed frequency recovery. This however is not “true” inertia but more like a type of FFR. ➢ **Battery Energy Storage System (BESS)** to provide fast frequency response and avoid using fast starting diesel generators in isolated systems, like islands. The study indicated it is not economically justified for Continental Europe except with “second life batteries” In medium-term, TSO can install synchronous condensers or innovative STATCOM with storage capability (as of today they rely on frequency measurement, but grid-forming control development could make them equivalent to synchronous condensers), which can allow for synergies with measures for reactive power compensation. With expected evolutions on grid forming, storage, converter-based generation (i.e. solar, wind) and HVDC systems could also provide these services if required via grid-codes. Costs occur at adding (small) storages to devices, both for the storage itself and its internal connection via power electronics. Deriving a share of inertia from HVDC links interconnecting synchronous areas (or from HVDC links

	integrated in AC grids after a system split) is possible, but also not state of the art yet (manufacturers see only monodirectional support as available today). One can be confident that technological innovations mainly based on inverter applications, like synthetic inertia and grid forming issues will contribute to inertia. It is, however, not yet possible to assume that this kind of technologies will be able to partially or totally counteract the gradual decrease of inertia.
Cost estimations	*No cost estimation provided*
Reviewer's comment	
The link between global (inertia) and local (voltage and short-circuit power) issues is made. The 500 ms window is mentioned, with the possibility to shorten it to 100 ms. Maximum admissible RoCoF is also discussed. Some of the technologies mentioned are for FFR, not inertia (wind generation units "synthetic inertia", Statcom with storages in GFL mode).	

8.2.4. AEMC, AEMO, "Essential system services and inertia in the NEM", 2022

Title: Essential system services and inertia in the NEM		
Institution: Australian Energy Market Operator (AEMO)	Authors: Clare Stark, Nicole Dodd.	
Date Published: June 2022	Pages: 22	Document Type: Technical report
Keywords: Essential system services, power system security, inertia, market.		Link: https://www.aemc.gov.au/sites/default/files/2022-06/Essential%20system%20services%20and%20inertia%20in%20the%20NEM.pdf

Abstract:

Essential system services (ESS) help keep the electricity grid in a safe, stable, and secure operating state. Getting the right ESS at the right time and in the right locations is vital for efficiently promoting consumers' interests as the sector undergoes unprecedented change as we transition to net zero.

The ESB's post 2025 recommendations set out a recommended way forward for ESS. This recognised that there is significant value where resources can provide flexibility and essential capabilities, allowing system needs to be met through a different mix of resources to what is used today. Stakeholder feedback suggested that addressing missing system services cannot wait until 2025.

Taking steps to identify, specify, value and procure these services will incentivise service providers to offer their diverse technical capabilities to market and ensure least cost outcomes for consumers. So the AEMC & AEMO have been working together to progress a number of power system security related projects.

This purpose of this paper is to:

1. set out the progress on ESS reform initiatives to date and
2. to set out more detail on the potential next priority in ESS – inertia

The ESB recommended using AEMO's Engineering Framework to consider technical requirements for inertia, including to coordinate and draw from other related initiatives, ahead of moving towards its long-term priority vision of a spot market approach for valuing and procuring inertia. This work and the current reforms on foot

<table>
<tr><td colspan="3">are expected to inform the ESS reform pathway for development of an inertia spot market and allow for the market to evolve as it matures.</td></tr>
<tr><th colspan="3">Characteristics of the power system involved</th></tr>
<tr><td>Geographical area: Australia</td><td>Size: East coast of Australia (~200 TWh, 23 million inhabitants, system length of about 5000 km with 40 000 km of lines and cables)</td><td>Interconnection level:</td></tr>
<tr><th colspan="2">Type of solution considered</th><td>Market</td></tr>
<tr><th colspan="3">Analysis of the publication according to proposed focus areas</th></tr>
<tr><td>Key challenges relate to inertia</td><td colspan="2"> The first step to move to a lower inertia system is to define and value inertia. The initial inertia reform initiative is focused on continuing to analyse frequency services, synchronous inertia, and equivalent synthetic inertia, as well as interactions with other ESS. In the longer term, this work is expected to inform the ESS reform pathway for development of an inertia spot market. The first step to move to a lower inertia system is to define and value inertia. The initial inertia reform initiative is focused on continuing to analyse frequency services, synchronous inertia, and equivalent synthetic inertia, as well as interactions with other ESS. In the longer term, this work is expected to inform the ESS reform pathway for development of an inertia spot market. </td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">Not addressed in details.</td></tr>
<tr><td>Considerations related to national needs due to potential splits</td><td colspan="2">The AEMC introduced a framework in 2017 to ensure security critical inertia when regions are at risk of ‘islanding’ from the rest of the NEM. Under this framework, AEMO is required to assess the minimum and secure operating levels of inertia for each region, the projected level of inertia in that region over the following five years, and the likelihood of the region becoming islanded. If AEMO identifies a projected shortfall in a region at risk of islanding, the relevant TNSP is required to procure the inertia or alternative frequency control service (including FFR) to meet this shortfall.</td></tr>
<tr><td>Evolution of inertia needs (based on analysis of underlying drivers)</td><td colspan="2">AEMO’s Draft 2022 ISP provides inertia projections out to 2036-37. Appendix 7 of the ISP details this analysis on inertia, noting the assumption that synchronous connection across the NEM would provide a strong inertia base is being challenged and requires review</td></tr>
<tr><td>Proposition of solutions to secure inertia</td><td colspan="2"> AEMO has tools to address inertia levels if the safety and security of the power system is threatened in the operational timeframe, including: Constraining interconnectors to reduce the largest contingency size, which may result in more synchronous generators operating in the region to meet demand
Using directions as a last resort, for example, to direct a synchronous machine online if insufficient inertia is available in operational timeframes.</td></tr>
</table>

	AEMO has set up a process to move to a lower inertia system, including work to define and value inertia. This process consists of the following steps: - A review of Frequency Operating Standard (FOS) which could include RoCoF limits, a maximum contingency size, and the potential for system-wide inertia floor. - Commencement of Very Fast Frequency Control Ancillary Services (FCAS) markets which will consider the level of system inertia. - Primary Frequency Response (PFR) incentive arrangements rule change, encouraging more widespread contributions of frequency control. - Operational Security Mechanism rule change, - Considering the role of FFR as an inertia support service under the framework for regions at risk of islanding. - Coordinating technical studies and activities to understand requirements and supply options for ESS including inertia. - Annual review and declaration of inertia shortfall across regions. - Projecting inertia and anticipate shortfalls to 2036-37. - Provide weekly frequency data report. - Prepare future market arrangements for managing RoCoF in Western Australia. - Understand power system requirements and inertia capabilities of different technologies, such as grid-forming battery energy storage systems (BESS). - Require minimum 3,5 years notice of generation exit, with a proposed extension to 5 years. The AEC proposes a design for the forecasting, dispatch, and settlement of an inertia market. Market participants would be able to place energy only, energy and inertia, or inertia only bids which would then be co-optimised through the NEM Dispatch Engine (NEMDE). The market would allow for the procurement of inertia from both synchronous and non-synchronous resources to the extent they are capable of meeting AEMO's technical definition of inertia. Participation in the Inertia Ancillary Service market would be voluntary.
Technologies that are foreseen to provide inertia	AEMO has published an Engineering Framework 'white paper' (https://aemo.com.au/newsroom/news-updates/application-of-advanced-inverters) to help fast track the deployment of advanced inverter capabilities. Industry and other stakeholders are also undertaking several trials that will inform understanding of power system requirements and inertia capabilities of different technologies, such as grid-forming battery energy storage systems (BESS).
Cost estimations	*No cost estimation provided.*
Reviewer's comment	
This document sheds light on the actions implemented in Australia to make the transition to a low inertia system. it is interesting to note the AEC's determination to create an inertia spot market offering participants to	

<table>
<tr><td>place energy only, energy and inertia, or inertia only bids which would then be co-optimised through the NEM Dispatch Engine (NEMDE).</td></tr>
</table>

8.2.5. Agora Energiewende, System stability in a renewables-based power system

<table>
<tr><th colspan="3"><u>Title:</u> System stability in a renewables-based power system</th></tr>
<tr><td><u>Institution:</u> Agora Energiewende</td><td colspan="2"><u>Authors:</u> Markus Pöller</td></tr>
<tr><td><u>Date Published:</u> August 2024 (draft)</td><td><u>Pages:</u> 111</td><td><u>Document Type:</u> Study report</td></tr>
<tr><td colspan="2"><u>Keywords:</u></td><td><u>Link:</u> draft report provided by DG Ener</td></tr>
<tr><td colspan="3"><u>Abstract:</u>

This report analyses the question, how system stability can be maintained in a power system that is dominated by inverter-based renewable electricity generators without any short-term storage capability, in contrast to a conventional power system, which is dominated by synchronous machines providing short-term storage through their rotating masses. This report aims at creating an understanding of the different elements of stability, and how they are affected by the change in generator technologies. In addition to this, this report also analyses the impact of the massive integration of VRE on system stability resulting from increased power transfers across relevant transmission corridors, enabled by the use of HTLS conductors, which drives the system closer to its stability limits.

This report further discusses future system service requirements and strategies to provide those services (e.g. mandatory requirements, auctions, market-based, etc.).</td></tr>
<tr><th colspan="3">Characteristics of the power system involved</th></tr>
<tr><td><u>Geographical area:</u> Europe</td><td><u>Size:</u> Very large</td><td><u>Interconnection level:</u> Highly interconnected</td></tr>
<tr><th colspan="2">Type of solution considered</th><td>Challenge/Technology/Market</td></tr>
<tr><th colspan="3">Analysis of the publication according to proposed focus areas</th></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">Voltage stability and oscillatory stability restrict the maximum power transfer across a line or a set of lines (transmission corridor). In countries with very long lines, it is common practice to operate the system with stability constraints calculated using offline (or online) simulation tools. As a result, the reduced inertia capacity offered by synchronous generators has an impact on the exchange capacities of interconnected systems.

System services to ensure power system stability:

• Active power based services:
o Manual/automatic frequency regulation reserve (mFRR/aFRR), i.e. secondary and tertiary frequency control reserve
o Frequency containment reserve (FCR), i.e. primary frequency control reserve
o Frequency-sensitive demand response
o Artificial inertia/Fast frequency control (< 500 ms)
o Synchronizing inertia (activated through voltage angle variations)
• Reactive power based services:
o Static voltage support (reactive power provision in steady state)
o Dynamic voltage support (reactive power provision in the time frame of some ms)</td></tr>
</table>

	- o Short circuit current *(reactive current support in response to a fault activated in less than 30 ms)* - System restoration: Black start capability
Main drivers of inertia needs	Variable renewable energies (VRE, wind and PV generation) can have a considerable impact on system stability: - VRE are converter-driven generators instead of large, directly coupled synchronous machines - VRE is typically installed remotely from load centers and at lower voltage levels than large conventional power plants.
Considerations related to national needs due to potential splits	System split events always lead to an active power imbalance in each of the resulting islands and consequently to frequency stability issues. In such case, to ensure that “islands” can “survive” and avoid a total black out, the following is required: - There must be sufficient inertia in each island. - The power imbalance (resulting from power transfers across opened corridors prior to the system separation) is within acceptable limits. - There is an effective and selective underfrequency load shedding scheme in place. - Generators reduce their active power output sufficiently quickly to avoid uncontrolled over-frequency disconnection of generators. - There is sufficient reactive power available in each island to maintain the voltage within the permitted limits.
Evolution of inertia needs (based on analysis of underlying drivers)	455GW of additional inertia will be required in the CE-system to eliminate all “Global Severe Splits”4 in the NT2030 scenario and to reduce the number of “Global Severe Splits” to very low values (e.g. 0.15% of all relevant splits) in all other scenarios, including DE2040 and GA2040. This is equivalent to around 57GW of synchronous machine power plants or around 20GW of BESS storage or dedicated synchronous condensers. Distribution of the overall required inertia between the different ENTSO-E-member states will have to be identified by additional studies.
Proposition of solutions to secure inertia	
Technologies that are foreseen to provide inertia	“Grid Forming Capability” mainly describes a combination of: - Synchronizing inertia (phase jump power and inertia) - Dynamic voltage support - Short circuit current Different technologies can provide these services: - Active power based services always require an energy source (possible to use storage components in case of short-term services). It requires the generator to operate with an active power reserve (very expansive in case of VRE -> for FCR, aFRR/mFRR, will be more and more provided by storage components like BESS as in Germany). - Synchronizing inertia can be provided by - o synchronous machine power plants and synchronous condensers - o utility-scale BESS combined with a grid forming converter

Cost estimations	To provide Grid Forming Capability, also when they are not generating, synchronous machine based peaking plants (e.g. H2-gas-turbines) must be equipped with self-synchronizing clutches (SSC) and potentially additional flywheels to enhance their inertia. This can be provided at relatively low additional cost. The provision of Grid Forming Capability from wind and solar plants would be much more expensive and less effective. **A classification of costs (high/medium/low) by technology (see page 101), but no quantification is provided.**
Reviewer's comment	
This comprehensive study provides exhaustive details of potential solutions. It also includes some basic information on technologies' costs. However, no concrete figures or orders of magnitude are provided; the study only distinguishes between costly and less costly solutions.	

8.2.6. Amprion, "Marktgestützte Beschaffung von Momentanreserve", 2023

Title: Marktgestützte Beschaffung von Momentanreserve		
Institution: Amprion	Authors: Consentec GmbH, Universität Stuttgart, Technische Universität Braunschweig	
Date Published: March 2023	Pages: 60	Document Type : Report
Keywords: Market-based inertia procurement, tender system, bonus system,		Link: https://www.amprion.net/Dokumente/Transparenz/Studien-und-Stellungnahmen/2023/Marktgest%C3%BCtzte_Beschaffung_Momentanreserve.pdf
Abstract: To meet the existing and foreseeable demand of inertia, three forms of procurement are possible. Self-provision of the TSOs by integrated grid components, market-based procurement and regulations which prescribe for the provision of inertia. A market-based procurement of inertia in the form of a tender and a bonus system would be feasible. This study evaluates the advantages and disadvantages of these two systems.		
Geographical area: Germany	Size:	Interconnection level:
Type of solution considered		Market
Analysis of the publication according to proposed focus areas		
Key challenges related to inertia	The analysis done in this study shows that critical ROCOF situations in Germany can emerge in case of low RES feed-in situations because it causes large volumes of imports, meaning that in case of system splits the ROCOF can exceed the threshold of 1 Hz/s.	
Main drivers of inertia needs	This study evaluates that there is a clear correlation between the wind feed-in and the resulting ROCOF after a system split.	
Considerations related to national needs due to potential splits	The study mentions that a distinction is made between "normal operation" and "emergency operation". In normal operation, scenarios are relevant in which active power imbalances occur than are below the 3 GW reference incident. This is distinguished from "emergency operation" with scenarios in which there is no longer an interconnected grid. The resulting active power imbalances are greater than the 3	

	GW assumed in the reference incident. In this case the existing system protection plan already provides measures (LFSM, underfrequency load shedding).
Evolution of inertia needs (based on analysis of underlying drivers)	Analyses for future scenarios show that even with a sharp decrease in inertia due to the expansion of converter-based feed-in, the **3 GW reference incident does not pose a significant challenge to the stability of the interconnected grid**. To evaluate the inertia requirement in Germany, this study analysed representative split scenarios. Two cases of split separation are considered, one with a resulting underfrequency scenario in Germany and one with a resulting overfrequency. Based on the analyses, a demand for additional inertia (in addition to the inertia procured by SGs) can be derived for the hours in which a frequency limit violation occurs.
Proposition of solutions to secure inertia	To meet the existing and foreseeable demand of inertia, three forms of procurement are possible. Self-provision of the TSOs by integrated grid components, market-based procurement and regulations which prescribe for the provision of inertia. The study analyses the interest of **a market-based procurement of inertia.** Tenders could enable the procurement of part of the demand for inertia, but they are sometimes at risk for the suppliers. The cost uncertainty on the supplier side could lead to the submission of bids that would be lower than the actual cost. Furthermore, tenders in the form of a day-ahead market don't provide much reliability of planning for suppliers regarding research and development and other transaction costs to be allocated. Procurement via a tender model could then be inefficient. It is questionable whether the requirements for sufficient market liquidity are met in the current situation and thus whether a market failure can be ruled out. A bonus system would also mean that plant operators would be free to provide or not provide inertia given the proposed bonus. The TSO offers a fixed price for an inertia availability. The fixed price would provide reliability for suppliers and **encourage investment in the development of grid-forming converters**. However, this system does not allow a direct control of the procured quantity. There is also a risk of overfunding of the parameters are not set properly. This study thus considers a **bonus system** focused on wind turbines and central battery storage systems to be a better choice for a **short-term market-based procurement** compared to a tender system. It would be possible to replace the bonus system with another model (tender for example) when the market maturity of the required plants has been reached. The proposed bonus system for instantaneous reserve incentivizes power systems, such as wind turbines and battery storage, to provide rapid response reserves by offering financial compensation in EUR/MWs. The bonus varies by technology type, reflecting market maturity and development costs—battery storage, being more advanced, receives a lower bonus than wind turbines, which require further investments. The study would suggest a lower bonus for wind turbines since they are only deemed capable of providing negative inertia while battery storage can provide both positive and negative inertia. To qualify, systems must meet strict technical requirements proving their capability to deliver instantaneous reserve. Bonuses are structured to decline over time for emerging technologies like wind turbines. A key benchmark is the cost of fully integrated grid components (including grid-forming converters), ensuring bonuses do not exceed the cost of using these technologies. The system also considers availability conditions, linking payouts to a minimum availability throughout the year. Additionally, differentiation may apply based on time (investment stage), location

	(grid stability needs), and system separation scenarios, ensuring reserves are provided where and when needed. Compared to a market-based procurement, regulations have the advantage of providing more certainty about the quantities procured. While, in the case of market-based procurement, each supplier can decide for itself whether or not to participate in the market, in the case of regulatory regulations each supplier is subject to mandatory provision. The central disadvantage of regulations is that suppliers would be forced to provide inertia and would thus have to provide inertia regardless of their costs. This leads to inefficient investments on the one hand and inefficient resource allocation on the other hand. In extreme cases, individual technologies might no longer be profitable. The advantages of market-based procurement include the fact that it could be implemented at relatively short notice and can lead to efficient resource allocation and efficient investment incentives. A disadvantage of market-based procurement is that the market outcome can never be predicted and thus there is uncertainty regarding the quantities and costs of inertia. In addition, a market-based form of procurement of inertia is always associated with transaction costs and a market failure cannot be ruled out in principle. In the long-term, inertia provision would rely on all three pillars: integrated grid components, technical connection rules and market-based procurement.
Technologies that are foreseen to provide inertia	• Wind turbines and PV systems (only deemed available to provide negative inertia) • Central battery storage systems
Cost estimations	*No cost estimation provided*
Reviewer's comment	
An interesting study that evaluates the need for inertia based on system splits events and then determines what market could be used to procure this inertia.	

8.2.7. DTU, Electric Power System Inertia: Requirements, Challenges and Solutions

Title: Electric Power System Inertia: Requirements, Challenges and Solutions		
Institution: DTU (Technical University of Denmark)	Authors: Rezkalla, Michel Maher Naguib; Pertl, Michael Gerold; Marinelli, Mattia	
Date Published: August 2018	Pages: 18	Document Type: Scientific paper
Keywords: Frequency Control, Synchronous inertia, Synthetic inertia, Virtual Synchronous Machine.		Link: https://link.springer.com/article/10.1007/s00202-018-0739-z
Abstract: This paper presents a review of the various solutions and technologies that could potentially compensate for reduction in system inertia. The solutions are categorized into two groups, namely synchronous inertia and emulated inertia employing fast acting reserves (FARs).		

Characteristics of the power system involved		
Geographical area: Europe	Size: Very large	Interconnection level: Highly interconnected
Type of solution considered		Technology
Analysis of the publication according to proposed focus areas		
Key challenges related to inertia	From TSO perspective, the reduction of system inertia has mainly two implications on system frequency stability, namely: 1) larger RoCoF, which results in possible tripping of grid components, especially embedded renewable electricity generation; and 2) higher frequency deviations (nadirs/zeniths), potentially leading to load shedding and, in the worst case, system collapse. Indeed, conventional synchronous generators are put to higher risk of instability as they are accelerating faster, thus reaching the maximal rotor angle earlier.	
Main drivers of inertia needs	The secure operation area for a given operating point is delimited by maximum allowed RoCoF, steady state requirement and the frequency nadir. Which constraint dominate others is an indicator of how the grid requirements are evolving.	
Considerations related to national needs due to potential splits	*No consideration related to potential splits.*	
Evolution of inertia needs (based on analysis of underlying drivers)		
Proposition of solutions to secure inertia	The solutions are categorized into two groups, namely synchronous inertia and emulated inertia employing fast acting reserves (FARs). FAR are divided into three groups based on the applied control approach, namely virtual synchronous machines, synthetic inertia control and fast frequency control. EirGrid has proposed a RoCoF modification in the grid code (1 Hz/s over 500 ms instead of 0.5 Hz/s, which is sufficient to cover for the loss of the current largest single infeed). EirGrid and SONI (Northern Ireland) have established a minimum value of rotational kinetic energy in the system as an operational constraint during the dispatch phase *(Inertia floor).*	
Technologies that are foreseen to provide inertia	National Grid started to procure fast reserves controlled with frequency deviation *(Fast Frequency Control - FFC).* Hydro-Quebec requires wind power plants to be equipped with an inertia emulation system RoCoF based control *(Synthetic inertia control - SIC).* Virtual Synchronous Machine (VSM) is a detailed mathematical model that tries to mimic the exact behavior of Synchronous Generators (SG) by controlling a power	

electronic converter. There are 2 main models for VSM: voltage reference or current reference.

Control Schemes	Key Features	Weaknesses
VSM	• Accurate representation of SG model • Frequency derivative not required • Black-start capability	• Can lead to numerical instability • Protections of the voltages and currents of the converter cannot be easily included
SIC	• Simple implementation compared to VSM	• Frequency derivative required • No black-start capability • System susceptible to noise
FFC	• Control type similar to conventional droop control in SGs • Local control (i.e. communication-less) • Stable performance	• No black-start capability

Frequency measurement accuracy is a challenge to develop emulated inertia services and, with the technological progress in microprocessors and cheaper computational power, many numerical methods for frequency measurement are applied and proposed.

The same applies to RoCoF measurement which is a key parameter in delivering synthetic inertia.

The paper also lists and discusses suitable technologies for mitigating the RoCoF:

- AC Interconnection
- Compressed Air Energy Storage
- Power Plant Technical Minimum Reduction
- Pumped Storage Hydro
- Synchronous Condensers
- Wind Turbines which can offer synthetic inertia
- Demand Side Management
- Flywheel
- HVDC Interconnectors which have the ability, according to several studies, to provide frequency control services, including inertia emulation and primary frequency control
- Various Energy Storage Technologies which can respond within 1 ms

Cost estimations	*No cost estimation provided*

Reviewer's comment

This paper summarizes existing solutions and those under study to overcome the inertia deficit. It also offers a classification of the proposed solutions. The solutions are not detailed but presented in summary form. The strengths and weaknesses of each solution are discussed.

8.2.8. Tractebel, "Penetration of renewables and reduction of synchronous inertia in the European power system – Analysis and solutions", 2018

Title: Penetration of renewables and reduction of synchronous inertia in the European power system – Analysis and solutions		
Institution: European Commission	Authors: Pieter Tielens (Tractebel Impact), Pierre Henneaux (Tractebel Impact), Stijn Cole (Tractebel Impact)	
Date Published: November 2018	Pages: 75	Document Type: Report
Keywords:		Link: https://op.europa.eu/en/publication-detail/-/publication/4711575c-6506-11eb-aeb5-01aa75ed71a1/language-en
Abstract: In conventional power plants, synchronous generators are able to store kinetic energy in their rotating mass. This makes the network less prone to frequency fluctuations. Renewable units, however, are equipped with a power electronic converter and are therefore decoupled from the grid and provide no inertia to the system. As a low system inertia can result in high RoCoF and frequency deviations that can lead to load shedding or even blackouts, new solutions are necessary. TSOs in large synchronous areas currently only include a RoCoF withstand capability (for new units) in their grid code. Island systems (like Ireland or GB) currently try to limit the maximum RoCoF by **limiting the largest credible loss** or by keeping **inertia above a critical value**. Although a substantial increase in converter connected penetration is expected by 2030, **this study shows that there will remain enough inertia in the system to cope with imbalances larger than the current reference incident.**		
Characteristics of the power system involved		
Geographical area: Continental Europe	Size: Very large	Interconnection level: Highly interconnected
Type of solution considered		Technology
Analysis of the publication according to proposed focus areas		
Key challenges related to inertia	With the increased penetration of renewable energy sources like wind and solar, which are connected to the grid via power electronics and do not inherently contribute mechanical inertia, the overall system inertia decreases. This makes the system more vulnerable to frequency instability. Lower inertia results in higher rates of change of frequency (ROCOF) following disturbances, which can lead to significant frequency deviations. This increases the risk of system instability, including load shedding or blackouts. Higher ROCOF values may lead to false tripping of ROCOF relays designed to protect distributed generation, which can exacerbate the instability. These ROCOF relays are often applied to protect distributed generation against islanding (loss-of-mains protection).	

	It should be noted that events with large, sustained frequency gradients are quite rare in large synchronous areas if the system remains interconnected. In continental Europe, ROCOF values of only 5-10 mHz/s are observed after a power plant outage of 1 GW.
Main drivers of inertia needs	The primary factor determining the required level of inertia in a power system is the admissible RoCoF for the power system. Based on studies by ENTSO-E's "System Protection & Dynamics" working group, the following ROCOF thresholds are recommended: • **±2 Hz/s** for a 500 ms moving average window. • **±1.5 Hz/s** for a 1-second moving average window. • **±1.25 Hz/s** for a 2-second moving average window. These thresholds help define **the minimum level of inertia needed** in the system. A lower allowable RoCoF requires **higher inertia**, as more stored kinetic energy is needed to slow the frequency change. Conversely, if the system can tolerate a higher RoCoF, it may be possible to operate with **lower inertia**, but this can increase the risk of triggering protection mechanisms such as generator disconnections or load shedding.
Considerations related to national needs due to potential splits	Some systems are protected against islanding by means of ROCOF relays. In the case of a low system inertia, false tripping of these relays may occur during a system imbalance. This would aggravate the initial event since large amounts of generation would be disconnected simultaneously. In Ireland, half of the wind turbines uses this type of relays. A solution is to increase the ROCOF settings or to replace them with other relays such as vector shift relays.
Evolution of inertia needs (based on analysis of underlying drivers)	The study determined **how low system inertia in CE can go without risking reaching a 1 Hz/s or 2 Hz/s ROCOF in the EUCO30 scenario**. The study evaluated the maximum and minimum kinetic energy available in CE in 2030 and obtained a minimum value of 661 GWs available. **This minimum kinetic energy content of 661 GWs corresponds to an imbalance of 26 GW and 52 GW for respectively a ROCOF of 1 Hz/s and 2 Hz/s**. We see that these values are **far greater than the current reference incident of 3 GW**. The Continental European system benefits from its size since inertia is roughly proportional to the size of the system. For example, the maximum value for the ERCOT system (Texas) is 389 GWs. **However, higher imbalances than the current reference incident can possibly be encountered during a system split**.
Proposition of solutions to secure inertia	Solutions include: • Limit the injection at a single point of the network, since the ROCOF after a power imbalance is proportional to the size of that imbalance (disregarding system splits) • Operate power plants at lower partial load • Add additional synchronous condensers. • Frequency support by converter (Virtual inertia): the control of renewable energy units can be modified to restore the coupling with the grid frequency and provide an additional power output in function of the measured frequency at their terminals. • Incentives for power plants with high inertia

	Some countries have created markets to secure inertia and provide other services faster than FCR. In Ireland a new service called SIR has been introduced. SIR stands for synchronous inertial response and compensates synchronous generators on the basis of their available stored kinetic energy to help manage frequency imbalances. A Fast Frequency Response (FFR) service is also being procured. It is an active power boost with a response time of 2-10 seconds.
Technologies that are foreseen to provide inertia	• Synchronous condensers • Energy storage systems (ESS) • Grid-forming converters • Virtual inertia from wind turbines, PV units, HVDC links
Cost estimations	The cost of providing the SIR and FFR services and 12 more system services providing stability for EirGrid (Ireland) was given in the study for the time period 2019/2020. The total annual cost was estimated to be between 169-220 M€ depending on the modelling scenario. The cost of SIR represents approximately 18M€ and FFR approximately 42M€.
Reviewer's comment	
The study does not consider system splits The study mixes inertia and FFR	

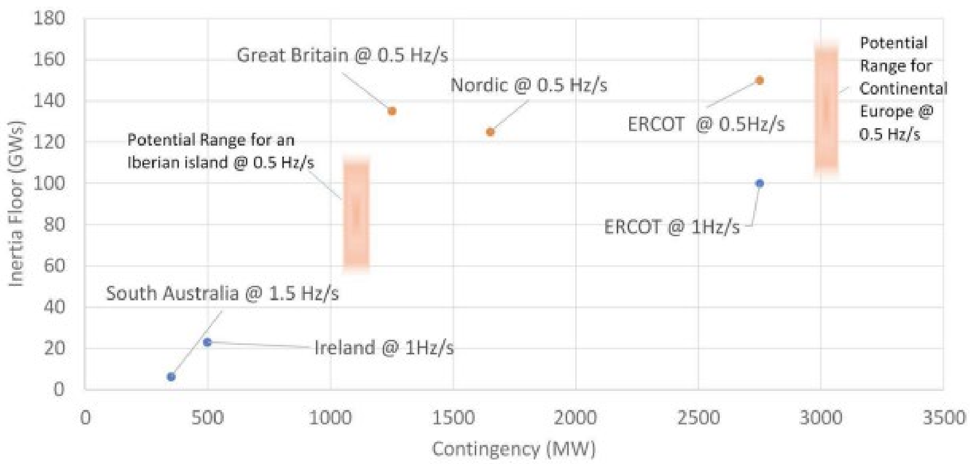
8.2.9. EPRI, Implications of Reduced Inertia Levels on the Electricity System: Technical Report on the Challenges and Solutions for System Operations with Very High Penetrations of Non-Synchronous Resources

Title: Implications of Reduced Inertia Levels on the Electricity System: Technical Report on the Challenges and Solutions for System Operations with Very High Penetrations of Non-Synchronous Resources		
Institution: Electric Power Research Institute (EPRI)	Authors: A. Tuohy, P. Dattaray, E. Farantatos, A. Kelly, E. Lannoye	
Date Published: June 2019	Pages: 150	Document Type: Technical Report
Keywords: Renewable Generation, Inertia, Fast frequency response, Inverter-based resources, Voltage-dip-induced frequency dip		Link: https://www.epri.com/research/products/000000003002014970
Abstract: The theoretical background for the impact of the reduction of stored kinetic energy (inertia) on frequency stability is provided in this report. The question of regional distribution of inertia is raised. Discussion on consequences of low inertia: misoperation of certain protection equipment that can lead to system split events, cascading generation trips, and the unintentional formation of active islands. Some solutions discussed: inertia floor, FFR services, etc.		
Characteristics of the power system involved		
Geographical area: N/A	Size: N/A	Interconnection level: N/A
Type of solution considered		

Analysis of the publication according to proposed focus areas	
Key challenges related to inertia	The key potential implications of low inertia on a power system are the following: ➢ More frequent domestic customer load shedding due to lower frequency nadirs from frequency imbalances. ➢ The ROCOF for frequency imbalance will increase. ➢ Increased risk **of cascading tripping of conventional and renewable generators with uncoordinated ROCOF-based loss of mains (LOM) protection** as well as low-frequency demand disconnection (LFDD). ➢ Increased risk of islanding distribution networks. In case of large frequency deviations, cascading loss of multiple generators due to their own frequency or mechanical protection can occur. In case of low frequency, the loss of a generator further decreases frequency and increases the risk of disconnecting additional generators, while a loss of generation due to high frequency helps correct the imbalance. Low system frequency conditions are therefore considered more severe. In a system relying on virtual inertia from wind turbines (like in Québec), another challenge is the slow active power recovery of online wind generation in response to a short-circuit disturbance. If the inverter-interfaced generation is not able to rapidly recover its active power output after the fault is cleared it can lead to system frequency transients. This phenomenon is called voltage-dip-induced frequency dip (VDIFD).
Main drivers of inertia needs	The main drivers for the requirement for the minimum inertia level across a synchronous area such as the CE system are : • The magnitude of the design contingency for a synchronous area (loss of the two largest plants for example) • The load-frequency sensitivity • System frequency nadir limits due to underfrequency protection • ROCOF limits due to ROCOF protection settings • Availability of FFR (Fast Frequency Reserve) • Peak demand • UFLS threshold (Under Frequency Load Shedding) In the absence of enough system inertia to contain the post-disturbance frequency swing, it is possible to use fast frequency response (FFR) services from inverter-based resources to provide new forms of frequency containment. These fast response services are not a true substitute for the automatic provision of inertia (because the need to measure the frequency or ROCOF inherently leads to a delayed response), but they do offer an effective way to ensure satisfactory frequency performance at reduced inertia levels. The availability of such fast response services would allow TSOs to push down their inertia floors while continuing to monitor system stability. Complex interaction among any markets for inertia, FFR or other system services, and traditional primary response should be expected.

Summary of inertia floors in planning studies

	ERCOT	GB	Ireland	NORDIC	AUSTRALIA (NEM)
UFLS	59.3 Hz	48.8 Hz	48.85 Hz	48.85 Hz	47.6 Hz
ROCOF	~ 1 Hz/s	0.5 Hz/s	1 Hz/s	0.5 Hz/s [57]	1.5/3Hz/s7
Contingency	2.75 GW	1.25 GW	0.5 GW	1.65 GW	0.35 GW
Inertia Floor	100 GW	135 GW	23 GW	125 GW	6.2 GW
Peak Demand	~73 GW	~60 GW	~6.5 GW	~72 GW	~36 GW



Considerations related to national needs due to potential splits	
Evolution of inertia needs (based on analysis of underlying drivers)	As distributed generation penetration is increasing there is an increased risk of the formation of electrical islands on distribution systems. The general solution is to install LOM or anti-islanding protection on the network. The problem is that the settings of ROCOF LOM relays were traditionally selected on systems with high inertia. In lower inertia systems, the **ROCOF after a generator trip may exceed these settings and cause inverter-based generation in the system to trip**. It must be noted that if the **ROCOF protection settings are too high, actual islands may go undetected when they occur**. System split events will result in a system or systems having over-generation and another system or systems having under-generation. The islanded system with under-generation would trigger load shedding to restore system frequency, but the speed with which it acts depends on the ROCOF. The islanded system with over-generation relies on limited frequency sensitive mode – over (LFSMO) (droop) control of synchronous and asynchronous generators to reduce power and restore the frequency. In this context, for large frequency deviations, other generators may trip following the initiating generator tripping. According to the study, the cascading loss of multiple generators resulting from underfrequency is maybe the greatest threat posed by poor frequency containment control or very low system inertia. TSOs should identify the ROCOF settings that are most appropriate for their future energy scenarios and assess the feasibility of deploying these settings to existing relays on the system. Even small systems can have thousands of ROCOF LOM relays meaning that the process of changing ROCOF settings on all relays on the system can be costly and difficult to achieve quickly.

	National Grid UK has revised its LOM ROCOF settings from 0,125 Hz/s to 1 Hz/s and EirGrid (Ireland) from 0,5 Hz to 1 Hz/s. **Each TSO or synchronous control area should be able to provide the necessary inertia for secure operation in case of system split for its individual stability in addition to its contribution to overall synchronous area inertia.**
Proposition of solutions to secure inertia	Some possible operating strategies to secure inertia (in a broad sense) or reduce the need include: • Keeping more synchronous inertia on the system without curtailing renewable generation by partially loading conventional, large turbine-generator thermal units •Dynamic floors for system inertia based on system conditions thanks to inertia monitoring and forecasting • Increasing generator droop control • Demand-side contributions for system inertia management such as electric vehicle charging/discharging, electric water heating, large industrial loads, and data centers Additionally, to the operating strategies listed above and the list of technologies provided below, other solutions include: • Combining inertial response with PFR and/or FFR products: **having volumes of FFR can mitigate the frequency nadir, meaning that increasing levels of FFR can reduce the need for inertia**. TSOs can for instance use inverter-based resources to supplement the lost system inertia by supplying additional power in the **FFR time frame of the 2 seconds** after a frequency imbalance. The study mentions that in certain conditions, a combination of synthetic inertia and PFR using droop could provide good performance using wind and solar PV. However, it requires headroom that can be used up or down to provide the frequency response, which could result in a curtailment of resources. • Reduction of unit minimum generation setpoint (partial or minimal loading) • Demand-side response: by obtaining a quicker response from the demand-side resources that participate in its reserve market, ERCOT showed that it could reduce the critical level of inertia by 30%.
Technologies that are foreseen to provide inertia	Purely synchronous inertia technological solutions include: • Synchronous condensers • Rotating stabilizers: a synchronous machine designed with a high mass • Compressed air energy storage (operates like a normal gas turbine power plant; provides inertia and primary, secondary, and tertiary responses) • AC interconnectors: increased synchronous interconnections (this is being considered in South Africa to connect it to the southern African regions, increasing the synchronous area) • Wind turbines with induction generator technology (no inverter interface) Synthetic inertia supplements include: • Battery energy storage: the study refers to research done by Queens University Belfast that found that 360 MW of battery-based energy storage could provide the equivalent stabilization to Ireland's electricity system (which would normally be provided by 3000 MW of thermal generation). • Flywheels

	• Wind turbines through converter control loops • Distributed power system virtual inertia • Advanced control strategies of permanent magnet synchronous generator (PMSG)-based wind turbines for system inertia support • HVDC interconnectors • Hydraulic-pneumatic flywheel system in a wind turbine rotor for inertia control • Supercapacitors The time delays associated with signal measurements are the most significant differentiator between conventional inertia from synchronous sources and synthetic inertia from asynchronous sources. For example, time windows of 100 ms and 500 ms can significantly impact ROCOF measurements. The directives on what is an acceptable time window for activation of synthetic “inertial” response can be different depending on the TSO. It is during the initial period of frequency decline (after the triggering event) that the synthetic inertia impact is missing, where the ROCOF is very high, but most generators are designed to handle such transients for such short durations. The synthetic inertia can then very well complement and contain the ROCOF in the time frame of 0.5 s after the triggering event.
Cost estimations	If an inertia floor or constraint is in place, the redispatch costs (or out-of-market costs) associated with these constraints can be a good way to determine the costs of inertia. For example, a study in Ireland estimated that including an inertial constraint in a 2020 system simulation (37% wind energy) added €1–€10 million to system costs, a small fraction of the overall €11.5 billion operational costs. However, these costs are expected to rise with higher wind or solar penetration. By imposing an inertial constraint in a system such as Ireland, other out-of-market redispatch actions for voltage control, congestion management, or other reason may be avoided—leaving total system costs (market costs plus redispatch costs) the same or lower. In some regions, one of the costs that can be associated with an inertial constraint is the cost associated with curtailment of wind or solar power to ensure that enough synchronous resources are kept online. This is not an actual fuel or capital cost but may be associated with a need to make feed-in tariff payments, or other compensation, for wind or solar even though they do not produce energy. Provision of synthetic inertia of FFR from inverter-based resources may constrain output, which represents opportunity costs (while conventional generator do not experience opportunity costs for the provision of inertia).

Reviewer's comment

- 500 ms window is mentioned
- FFR above 500 ms is mentioned and the fact GFL can participate to it too.
- Opportunity cost for IBR providing inertia services are mentioned.

Thorough report that covers most topics related to inertia.

8.2.10. ERCOT Inertia procurement

Title: ERCOT Inertia procurement

<table>
<tr><td>Institution: GE Energy consulting</td><td colspan="2">Authors: Unknown</td></tr>
<tr><td>Date Published: April 2023</td><td>Pages: 15</td><td>Document Type: Stakeholder presentation</td></tr>
<tr><td colspan="2">Keywords: Primary frequency response (PFR), Under frequency response (UFR)</td><td>Link:
https://www.ercot.com/files/docs/2024/03/20/02_GE-ERCOT_StakeholderPresentation_R6_new.pdf</td></tr>
<tr><td colspan="3">Abstract: The study's aim is to answer the following question: what limits should be defined for resources providing primary frequency response (PFR) in ERCOT?
The more specific study question is: as 1% droop resources (like BESS) displace 5% droop resources (SGs), what reliability risks emerge?</td></tr>
<tr><td>Geographical area: Texas</td><td>Size (GW) (Peak/Avg): 73,5/43</td><td>Interconnection level: ERCOT interconnection with other systems is very limited (~1.2 GW)</td></tr>
<tr><td colspan="2">Type of solution considered</td><td>Market</td></tr>
<tr><td colspan="3">Analysis of the publication according to proposed focus areas</td></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">The study focuses on the Primary frequency response (PFR), which occur after the SIR (Synchronous Inertial Response – which limits RoCoF) following a disturbance. The PFR arrests the frequency drop and generates a rebound to reach the steady state frequency. This study focuses on the worst case scenario regarding inertia with only 122 GW.s available, to analyse under which condition PFR can maintain grid stability.</td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">Not discussed here.</td></tr>
<tr><td>Considerations related to national needs due to potential splits</td><td colspan="2">Not discussed here.</td></tr>
<tr><td>Evolution of inertia needs (based on analysis of underlying drivers)</td><td colspan="2">Not discussed here.</td></tr>
<tr><td>Proposition of solutions to secure inertia</td><td colspan="2">The study evaluates multiple PFR configurations, with different distribution of batteries (BESS), for various disturbances. Most cases resulted in low risks. The study also compares PFR procurement with a majority of BESS (and some limited Synchronous Machines) to a procurement with synchronous machines only and concludes that the response is overall similar. ERCOT can therefore rely on BESS with 1% droop for PFR.
The study recommends that an individual unit provision of PFR must not exceed 10% of the total PFR requirement. Otherwise, the failure of one PFR unit may be greater than the margin between the ERCOT criteria (59.4 Hz) and the UFLS.</td></tr>
<tr><td>Technologies that are foreseen to provide inertia</td><td colspan="2">The SIR is only achieved here through synchronous machines (SMs). But PFR can be achieved by SMs, BESS, Loads, Wind & PV.</td></tr>
<tr><td>Cost estimations</td><td colspan="2">No cost estimation provided</td></tr>
</table>

<table>
<tr><th>Reviewer's comment</th></tr>
<tr><td>The key point of this presentation is that a PFR system relying fully on 1% droop resources can work for a system the size of Texas, as long as no individual unit providing PFR exceeds 10% of the PFR requirement.</td></tr>
</table>

8.2.11. ETH, A Market Mechanism for Virtual Inertia

<table>
<tr><th colspan="3"><u>Title:</u> A Market Mechanism for Virtual Inertia</th></tr>
<tr><td><u>Institution:</u> Swiss Federal Institute of Technology (ETH)</td><td colspan="2"><u>Authors:</u> Bala Kameshwar Poolla, Saverio Bolognani, Li Na, Florian Dörfler</td></tr>
<tr><td><u>Date Published:</u> January 2020</td><td><u>Pages:</u> 10</td><td><u>Document Type:</u> Scientific paper</td></tr>
<tr><td colspan="2"><u>Keywords:</u> Low-inertia systems, robust optimization, mechanism design, power system planning</td><td><u>Link:</u> https://ieeexplore.ieee.org/abstract/document/8970289</td></tr>
<tr><td colspan="3"><u>Abstract:</u> In this article, a market mechanism, inspired by the ancillary service markets in power supply, is proposed to procure and pay for strategically located virtual inertia devices. This market mechanism is simulated on a network-reduced power system (three-region case).</td></tr>
<tr><th colspan="3">Characteristics of the power system involved</th></tr>
<tr><td><u>Geographical area:</u> study case</td><td><u>Size:</u> 12-bus case study</td><td><u>Interconnection level:</u> 3 regions case study</td></tr>
<tr><th colspan="2">Type of solution considered</th><td>Market</td></tr>
<tr><th colspan="3">Analysis of the publication according to proposed focus areas</th></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">The challenge is to set up a mechanism to mobilize available technologies to meet inertia requirements at all times, at the lowest possible cost.</td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">Not detailed. Inertia deficit is an assumption here.</td></tr>
<tr><td>Considerations related to national needs due to potential splits</td><td colspan="2">As the value of inertia and procurement thereof, is location-dependent, this article shows that this non-homogeneity prevents the existence of a global price for virtual inertia.</td></tr>
<tr><td>Evolution of inertia needs (based on analysis of underlying drivers)</td><td colspan="2">Not addressed.</td></tr>
<tr><td>Proposition of solutions to secure inertia</td><td colspan="2">In this paper, the problems of provisioning virtual inertia units and the affiliated payment architecture are considered within the framework of ancillary-service markets coupled with auctions.

In this way, the need for inertia and the ability of technologies to provide inertia (especially virtual inertia) are input data. This work consists in proposing a regulatory framework to ensure that the system will be able to offer sufficient inertia at minimum cost.

3 mechanisms are compared:</td></tr>
</table>

	- a possible regulatory allocation where inertia is allocated proportionally to the capacity of the virtual inertia devices, in order to meet the specifications regardless of cost, - a centralized planning approach, - a market-based approach. Simulations show that both centralized and market-based approaches enable the system to be operated at lower cost. Nevertheless, the article sees the market approach as a way to: - safeguard against market actors benefiting from submitting inflated bids, - ensure that the resulting payments incentivize market actors to participate in the auction, - assure non-negative returns (must run units without adequate remuneration).
Technologies that are foreseen to provide inertia	This article does not describe the technologies available to overcome the inertia deficit. It considers that the solutions are known, available and have an associated cost. This article focuses on the implementation of an economic mechanism to ensure the mobilization of these technological solutions.
Cost estimations	The simulations carried out use cost curves for each market actor able to provide an inertia service (the total of which can be seen in figure 6). However, the source of these data is not indicated, and it is not made clear whether they are evidence based or assumed.
Reviewer's comment	
This article is of interest insofar as it focuses on the implementation of a regulatory mechanism to ensure the supply of inertia (provided the technologies are available and installed) at least cost. Nevertheless, the fact that the experiment was carried out on a very small dataset means that the conclusions of this article should be treated with caution.	

8.2.12. Fairley, Can Synthetic Inertia from Wind Power Stabilize Grids?

Title: Can Synthetic Inertia from Wind Power Stabilize Grids?		
Institution:	Authors: Peter Fairley	
Date Published: November 2016	Pages: 2	Document Type: Press release
Keywords: renewables wind farms power grid frequency regulation Quebec wind turbines synthetic inertia		Link: https://spectrum.ieee.org/can-synthetic-inertia-stabilize-power-grids
Abstract: Wind energy farms can emulate the rotational inertia that conventional power plants provide to stabilize power grids. Next-generation technology will do it even better		
Characteristics of the power system involved		
Geographical area: Québec	Size: 34,187 kilometres of lines and 530 electrical substations	Interconnection level: Part of North American Electricity Reliability Corporation (NERC)
Type of solution considered		Technology
Analysis of the publication according to proposed focus areas		

Key challenges related to inertia	The energy recovery phase of synthetic inertia leads to a delay in the grid's frequency recovery. HQ plans to limit power reduction during recovery to no more than 20 percent of a wind turbine's capacity (They could have chosen to increase primary reserve capacity instead).
Main drivers of inertia needs	Québec had about 3,300-MW of wind power in 2016, but Canada's wind industry was calling for 8,000-megawatts more by 2025.
Considerations related to national needs due to potential splits	*No consideration related to potential splits.*
Evolution of inertia needs (based on analysis of underlying drivers)	In 2016, turbines capable of providing synthetic inertia accounted for two-thirds of Quebec's wind energy capacity.
Proposition of solutions to secure inertia	One solution is to keep old synchronous generators spinning in synchronisation with the grid. Another emerging option is discussed in this article: synthetic inertia. Synthetic inertia is achieved by reprogramming power inverters attached to wind turbines so that they emulate the behavior of synchronized spinning masses. Hydro-Québec began setting requirements for synthetic inertia in 2005. During a December 2015 transformer failure that took more than 1,600 MW of power generation offline, synthetic inertia kicked in 126 MW of extra power to address the resulting frequency drop (roughly the same contribution as conventional power plants).
Technologies that are foreseen to provide inertia	The first generation of ENERCON Inertia Emulation brought rotors back to their optimal speed as quickly as possible, using power estimation and closed-loop control to enable smooth and tunable re-acceleration.
Cost estimations	*No cost estimates.*
Reviewer's comment	
This article describes the potential development of synthetic inertia to overcome the inertia deficit caused by the reduction in the share of synchronous generators in the power system. Its purpose is to describe the orientations taken by HydroQuebec, which manages an interconnected network, pioneered the use of very high voltage 735-kilovolt (kV) alternating current (AC) power lines, with strong growth in the share of wind power.	

8.2.13. ERCOT, Inertia: Basic Concepts and Impacts on the ERCOT Grid

Title: Inertia: Basic Concepts and Impacts on the ERCOT Grid		
Institution: ERCOT	Authors:	
Date Published: April 2018	Pages: 25	Document Type: Whitepaper
Keywords:		Link: https://www.ferc.gov/media/inertia-basic-concepts-and-impacts-ercot-grid
Abstract:		

This white paper describes ERCOT's initiatives to track the trends of historical inertia in the ERCOT system and to develop tools and methods to mitigate negative impacts of low inertia availability that could arise in the future.

It describes the basics of synchronous inertia and provides information about typical inertia contributions from various resource types in the ERCOT generation fleet. It discusses factors influencing generator commitment patterns and, consequently, affecting system inertia in ERCOT. It illustrates historic inertia trends in ERCOT between 2013 and 2017. It presents a methodology for determining critical inertia (i.e., minimum level of system inertia at or above which the ERCOT system can be operated reliably with current frequency control practices). It summarizes current practices for control room monitoring and maintaining of inertia equal to or greater than the critical inertia level. It presents analysis of future base-level inertia (i.e., inertia that is expected based on specific resources' characteristics and protocol requirements). The section also attempts to estimate additional generation that will be needed to serve future load and its inertia contribution. It shows how various frequency control parameter changes influence critical inertia levels. It provides an international review of inertia related challenges and mitigation measures in power systems of similar size and renewable energy penetration levels as those of ERCOT.

Characteristics of the power system involved

Geographical area: Texas	Size (GW) (Peak/Avg): 73.5/43	Interconnection level:

Type of solution considered

Analysis of the publication according to proposed focus areas

Focus area	
Key challenges related to inertia	Critical Inertia is the minimum level of system inertia that is necessary to ensure ERCOT's fast frequency responsive resources can be effectively deployed before frequency drops below 59.3 Hz following the simultaneous loss of 2750 MW.
Main drivers of inertia needs	The following table lists relevant parameters of the systems facing low inertia issues:

	Ireland	UK	Nordic	Quebec	South Australia
Peak Demand, GW	6.4	53	70	39	3
Capacity from Wind and Solar	4 GW	>26 GW	10%	7%	35%
Minimum Inertia, GW*s	20	135	125	60	2
Resource Contingency Criteria, MW	500	1000	1450	1700	650
Issues	Lack of synchronizing torque, at RoCoF ≥0.5 Hz/s significant amounts of non-synchronous generation will trip	At RoCoF of 0.125 Hz/s some non-synchronous generation will trip; at 1 Hz/s all non-synchronous generation will trip	Slow PFR (hydro), time to UFLS is a concern	Low inertia (hydro), high RCC, slow PFR (hydro), time to UFLS is a concern	High (1-3 Hz/s) RoCoF after RCC, at which synchronous generation may trip and UFLS may malfunction

Considerations related to national needs due to potential splits	Not addressed.

<table>
<tr>
<td>Evolution of inertia needs (based on analysis of underlying drivers)</td>
<td>
In 2017, ERCOT has conducted an assessment of system inertia, based on historic data from 2013 through 2017, that can be expected in the future.
As a result of this analysis, ERCOT expected that, with 24 GW of installed wind generation by the end of 2020, synchronous inertia to be from 78 GW*s (68 installed + 10 additional inertia) to 100 (85 installed + 15 additional inertia) GW*s during high wind and low load conditions.
</td>
</tr>
<tr>
<td>Proposition of solutions to secure inertia</td>
<td>
Changes to various frequency control parameters can lower and thus improve the critical inertia level, such as:

shortening the time allowed for frequency response,
raising the frequency response trigger point,
lowering Under Frequency Load Shed (UFLS) setting,
decreasing the size of largest contingency.

Some of these measures have already been implemented (in 2018) in other systems with characteristics similar to the ERCOT grid. Other systems had already begun to address low inertia challenges through the use of synthetic inertia capability from wind generation resources and installing high inertia synchronous condensers:
<table>
<tr><th></th><th>Ireland</th><th>UK</th><th>Nordic</th><th>Quebec</th><th>South Australia</th><th>ERCOT</th></tr>
<tr><td>Monitor inertia & possible contingencies in Real-Time</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td><td>✓</td></tr>
<tr><td>Forecasts Inertia from DA into Real-Time</td><td>✓</td><td>✓</td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>Dynamic Assessment of Reserves based on inertia conditions and largest resource contingency</td><td></td><td>✓</td><td></td><td></td><td></td><td>✓</td></tr>
<tr><td>Limit RCC based on inertia conditions</td><td>✓</td><td>✓</td><td></td><td>✓</td><td>✓</td><td></td></tr>
<tr><td>Synchronous Condensers (for inertia)</td><td>✓</td><td>✓</td><td></td><td></td><td>✓ (particularly looking at high inertia SCs)</td><td></td></tr>
<tr><td>Enforce minimum inertia limit</td><td>✓</td><td>✓</td><td></td><td></td><td>✓ (for minimum inertia req.)</td><td>✓</td></tr>
<tr><td>Inertia market/auction/service inertia</td><td>✓</td><td></td><td></td><td></td><td>✓ (for above minimum inertia levels)</td><td></td></tr>
<tr><td>Faster Responding Reserves</td><td>FFR</td><td>Enhanced Frequency Response Service</td><td></td><td>Synthetic inertia from wind</td><td>“Contingency” FFR (frequency trigger) and “Emergency” FFR (direct event detection)</td><td>Load Resources providing RRS</td></tr>
</table>
</td>
</tr>
</table>

Technologies that are foreseen to provide inertia	Technologies that are foreseen to provide inertia (like synchronous condensers for example) are not detailed in this report. In 2017, ERCOT only used measures frequency control parameters.
Cost estimations	*No cost estimations provided.*
Reviewer's comment	
Detailed report on ERCOT system inertia requirements in 2017. After characterizing the inertia of ERCOT, an analysis of the ERCOT's system inertia for the period 2013-2017 is provided. This analysis shows that ERCOT's minimum as well as median system inertia level is not necessarily correlated the installed capacity of wind generation. Indeed, unit commitment patterns is the key dimensional element. The paper also defined the methodology used to determine the minimum level of system inertia and insists on the necessity to monitor system in real-time to tackle the increasing uncertainties to grid operations. Mitigation measures implemented to maintain system security are presented. Finally, the section 10 which is a short international review of inertia related challenge and mitigation measures that have been implemented in Ireland, UK, Nordic, Quebec, South Australia and ERCOT is particularly instructive. This report concludes on the relevance of exploring ideas of creating a market for inertial response.	

8.2.14. IEEE, Market Mechanism Design of Inertia and Primary Frequency Response with Consideration of Energy Market

Title: Market Mechanism Design of Inertia and Primary Frequency Response with Consideration of Energy Market		
Institution: IEEE	Authors: Kexin Li, Xichen Fang, Fei Teng	
Date Published: November 2023	Pages: 13	Document Type: Technical Report
Keywords: VRE (variable renewable energy), IPFR (inertia and primary frequency response), energy markets		Link: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=9956757
Abstract: The shortage of inertia and primary frequency response (IPFR) will be more severe in future power systems since conventional fossil-based synchronous generators are gradually being replaced by variable renewable energy (VRE) generators. To relieve the shortage of IPFR, corresponding market mechanisms should be designed and incorporated to motivate appropriate provision from various sources. The mechanism of IPFR provision from different types of generators and its tight relation with energy production should receive particular attention. This paper proposes a novel IPFR market mechanism in which the energy market and the inertia market are taken into joint consideration.		
Geographical area:	Size:	Interconnection level:
Type of solution considered		Technology
Analysis of the **publication according to proposed focus areas**		
Key challenges related to inertia	With the increase of the renewables penetration in power system, the lack of the inertia and primary frequency response resources will be apparent. Therefore, a will to use these renewables to provide IPFR emerges. In a system where renewables must contribute to IPFR, **the ability of VRE generators to provide IPFR are largely coupled with their ability to provide energy**. This needs to be considered when designing a market for IPFR.	

Main drivers of inertia needs	The role of the inertial and primary response is to decrease the frequency decline rate and make the frequency affordable before secondary and tertiary frequency responses are applied.
Considerations related to national needs due to potential splits	Not discussed in this paper.
Evolution of inertia needs (based on analysis of underlying drivers)	Not discussed in this paper.
Proposition of solutions to secure inertia	To ensure sufficient inertia, this paper proposes a framework for an Inertial and Primary Frequency Response (IPFR) market, allowing participation from both thermal and variable renewable energy (VRE) generators. A key aspect of this market is a differentiated pricing scheme that reflects the distinct characteristics of these generation types. For thermal generators, inertia and droop factors are fixed and independent of power output. Their participation in the IPFR market does not affect their available capacity or energy market bids. The system operator determines whether they remain online or offline based on system conditions, and generators earn revenue from both the IPFR and energy markets according to the clearing price. For VRE generators, virtual inertia and droop factors are dynamic and depend on the reserve margin (a portion of available capacity allocated for IPFR provision). These values adjust as reserve margins change throughout the day. To participate, VRE generators submit bids in both the energy and IPFR markets while also providing their maximum available capacity forecast. The system operator then optimizes market clearing results while considering system constraints and the operational characteristics of VRE. This approach enables efficient inertia procurement while integrating more renewable energy sources into frequency stability services.
Technologies that are foreseen to provide inertia	Generally, wind turbines and PV work in maximum power point tracking (MPPT) mode. In this mode, wind turbines and PV can't provide IPFR. To do so they must work under the de-rated mode, meaning they reserve a proportion of their available capacity to provide IPFR.
Cost estimations	The proposed IPFR market is applied (in addition to the energy market) to a modified IEEE 30- bus system with 26 generators, including 10 thermal generators, 8 PV stations and 8 wind turbine stations, with generation capacities based on CAISO (California) mix in 2045. System costs decrease in the market configuration in which VRE can provide virtual inertia, and the profits of generators increase regardless of the share of VRE generators. The IPFR accounts for 5,7% of the total system cost, but the system with IPFR has a 11,3% decrease in the total costs. This is because, with the proposed IPFR market, the thermal generators don't need to be online to provide IPFR and operate as minimum power output mode. That allows for more wind to be accommodated. Thus, the VRE utilization rate increases, and the system energy costs decrease.

Reviewer's comment

Interesting paper that includes details on the IPFR constraints modelling resulting in a detailed market clearing model.

It seems that this paper focuses on the provision of FFR and not inertia because wind turbines cannot yet provide inertia but only FFR (even if called "synthetic inertia").

8.2.15. Imperial College, Importance of Linking Inertia and Frequency Response Procurement: The Great Britain Case

Title: Importance of Linking Inertia and Frequency Response Procurement: The Great Britain Case		
Institution: Imperial College	Authors: Aimon Mirza Baig, Luis Badesa, Goran Strbac	
Date Published: June 2021	Pages: 6	Document Type: Scientific paper
Keywords: Ancillary services, frequency stability, renewable energy, unit commitment		Link: https://ieeexplore.ieee.org/abstract/document/9494998
Abstract: In this article, a market mechanism, inspired by the ancillary service markets in power supply, is proposed to procure and pay for strategically located virtual inertia devices. This market mechanism is simulated on a network-reduced power system (three-region case).		
Characteristics of the power system involved		
Geographical area: Great Britain	Size:	Interconnection level:
Type of solution considered		Market
Analysis of the publication according to proposed focus areas		
Key challenges related to inertia	The main challenge addressed by this paper is the assessment of the benefits of co-optimising the procurement of inertia and frequency response services instead of the current unlinked approach.	
Main drivers of inertia needs	Not detailed. Inertia deficit is an assumption here.	
Considerations related to national needs due to potential splits	Not addressed.	
Evolution of inertia needs (based on analysis of underlying drivers)	The main drivers of a higher need for frequency services in the GB system are: 1. the largest unit's loss (N-1) increases from 1.32GW to 1.8GW after the commissioning of nuclear plant Hinkley Point C, 2. the wind energy capacity increases from 25GW to 50GW to meet energy and climate targets. Wind capacities of 50 GW in GB are now expected before 2030 in the TSO's scenarios (around 2028-2029). The commissioning of unit 1 of Hinkley Point C is expected in 2029-2031. The future scenario assessed therefore approximatively represent 2030.	
Proposition of solutions to secure inertia	This paper focuses on understanding the importance of linking inertia and frequency response procurement in low-inertia systems, particularly in electricity grids with a large size of the worst possible contingency. The results presented can inform the design of ancillary-services markets that consider the interaction between inertia and frequency response in order to reduce the overall system cost.	

Technologies that are foreseen to provide inertia	Technologies are not discussed in this article.
Cost estimations	The cost of procuring ancillary services could increase by up to 165% in the future GB power system, if the current approach of unlinking the procurement of inertia and frequency response continues to be used. The savings, induced by co-optimisation of inertia and frequency response, are of £10m/month for the current GB system and of £60m/month for the future GB system, illustrating the value of the fast service EFR, particularly as the system level of inertia decreases in the future with the increase in non-synchronous wind energy capacity.

Reviewer's comment

This paper introduces a Stochastic Unit Commitment (SUC) model with frequency-stability constraints, used to quantify the economic value of linking inertia and frequency response, as this model considers uncertainty in RES generation. The three constraints taken into account in any grid are:

1. the maximum admissible RoCoF,
2. minimum acceptable value for a frequency drop (called frequency nadir)
3. the quasi-steady-state (q-s-s) requirement.

The current approach in place in GB (which unlinks the inertia and frequency response procurement) is compared to the strategy in which these two services are explicitly co-optimised (the SUC model). Such a reorganisation of the structure of ancillary-services markets should help limit the increase in costs of procuring ancillary services in GB in the coming years (estimated at 165% around 2030 compared to early 2020s).

8.2.16. NREL, Inertia and the Power Grid: A Guide Without the Spin

Title: Inertia and the Power Grid: A Guide Without the Spin

Institution: National Renewable Energy Laboratory	Authors: Paul Denholm, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley	
Date Published: May 2020	Pages: 48	Document Type: Technical report
Keywords:		Link: https://www.nrel.gov/docs/fy20osti/73856.pdf

Abstract:

Grid frequency, can drop if a large power plant or transmission component fails. Inertia is one of the grid services that help maintain power system's reliability. The importance of inertia to a power system depends on many factors, including the size of the grid and how quickly connected generators can detect and respond to imbalances. Using power electronics, inverter-based resources including wind, solar, and storage can quickly detect frequency deviations and respond to system imbalances. Replacing conventional generators with inverter-based resources, including wind, solar, and certain types of energy storage, has two counterbalancing effects. The Electric Reliability Council of Texas grid's (ERCOT) relatively small size, combined with its large wind deployment, has required it to compensate for declining inertia by adopting several low-cost solutions, including allowing fast-responding noncritical loads to respond to changes in frequency. In the Western and Eastern Interconnections, which are much larger than ERCOT, it is unlikely that any significant concerns related

<table>
<tr><td colspan="3">to maintaining frequency due to declining inertia will arise in the coming decade. Ongoing research points to the possibility of maintaining grid frequency even in systems with very low or no inertia (grid forming).</td></tr>
<tr><th colspan="3">Characteristics of the power system involved</th></tr>
<tr><td>Geographical area: US</td><td>Size (GW) (Peak/Avg) :
• Western: 168/100
• Eastern: 556/354
• ERCOT: 73.5/43</td><td>Interconnection level:</td></tr>
<tr><th colspan="2">Type of solution considered</th><td></td></tr>
<tr><th colspan="3">Analysis of the publication according to proposed focus areas</th></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">Replacing conventional generators with inverter-based resources, including wind, solar, and certain types of energy storage, has two counterbalancing effects. First, these resources decrease the amount of inertia available. But second, these resources can reduce the amount of inertia actually needed—and thus address the first effect.</td></tr>
<tr><td>Main drivers of inertia needs</td><td colspan="2">Inertia is one of the grid services that help maintain power system reliability. Understanding the role of inertia requires understanding the interplay of inertia and these other services, particularly primary frequency response, which is largely derived from relatively slow-responding mechanical systems.

The importance of inertia to a power system depends on many factors, including the size of the grid and how quickly connected generators can detect and respond to imbalances. A grid with slower generators needs more inertia to maintain reliability than a system that can respond quickly.</td></tr>
<tr><td>Considerations related to national needs due to potential splits</td><td colspan="2">No consideration related to potential splits.</td></tr>
<tr><td>Evolution of inertia needs (based on analysis of underlying drivers)</td><td colspan="2">In the Western and Eastern Interconnections, which are much larger than ERCOT, it is unlikely that any significant concerns related to maintaining frequency due to declining inertia will arise in the coming decade.</td></tr>
<tr><td>Proposition of solutions to secure inertia</td><td colspan="2">In the US, the Texas grid (ERCOT)'s relatively small size, combined with its large wind energy deployment, has required it to compensate for declining inertia by adopting several low-cost solutions, including allowing fast-responding noncritical loads to respond to changes in frequency.

This has enabled ERCOT to achieve increasingly high instantaneous wind energy penetrations (reaching a record of 58% in 2019) while maintaining reliability.</td></tr>
<tr><td>Technologies that are foreseen to provide inertia</td><td colspan="2">Using power electronics, inverter-based resources including wind, solar, and storage can quickly detect frequency deviations and respond to system imbalances. Tapping into electronic-based resources for this “fast frequency response” can enable response rates many times faster than traditional mechanical response from conventional generators, thereby reducing the need for inertia.

The development of new “grid-forming” inverters enables inverter-based resources to take a more active role in maintaining reliability and could be an integral technology for a purely inverter-based grid.</td></tr>
<tr><td>Cost estimations</td><td colspan="2">No cost estimations provided.</td></tr>
<tr><th colspan="3">Reviewer's comment</th></tr>
</table>

This technical report, very pedagogical, is interesting for this review although the analysis concerns electrical systems in the USA. After explaining the physical phenomenon, the evolution of needs of several grid services (including inertia) is evaluated depending on the size of the grid. ERCOT, which is the smallest of the three grids, has adopted several low-cost solutions (fast-responding noncritical loads) to accommodate a large wind energy deployment. In the Western and Eastern Interconnected systems, which are much larger, maintaining frequency notwithstanding declining inertia should not be an issue in the coming decade.

8.2.17. Ratnam, Future low-inertia power systems: Requirements, issues, and solutions - A review

Title: Future low-inertia power systems: Requirements, issues, and solutions - A review		
Institution:	Authors: Kamala Sarojini Ratnam, K. Palanisamy, Guangya Yang b	
Date Published: May 2020	Pages: 24	Document Type: Scientific paper
Keywords: Inertia control, Virtual synchronous generator, Large-scale integration of renewable energy sources, Rate of change of frequency		Link: https://www.sciencedirect.com/science/article/abs/pii/S1364032120300691
Abstract: This study focuses on the requirements of inertia and the corresponding issues that challenge the various country grid operators due to the large-scale integration of renewable energy sources. This study reviews the various control techniques and technologies that offset a decrease in inertia and discusses the inertia emulation control techniques available for inverters, wind turbines, photovoltaic systems, and microgrids. This study attempts to explore future research directions and may assist researchers in choosing an appropriate topology, depending on requirements.		
Geographical area:	Size:	Interconnection level:
Type of solution considered		Technology
Analysis of the publication according to proposed focus areas		
Key challenges related to inertia	The large-scale integration of RES into the grid can lead to frequency stability issues. The reduced inertia in the power systems leads to an increase in the ROCOF. A high ROCOF can then lead to a trip of relays and high-frequency nadir results in load shedding. To overcome the stability issues caused by low inertia, the RES could then participate in the frequency regulation and additional technologies providing inertia would then need to be installed.	
Main drivers of inertia needs	The study mentions the critical RES penetration limit as a key indicator of the inertia needs. The critical RES penetration limit is the instantaneous penetration value of RES that can be reached before the frequency can fall below the allowable range after an incident. This value depends on the frequency droop controller, the voltage droop controller and transients.	
Considerations related to national needs due to potential splits	Not discussed in this study.	
Evolution of inertia needs (based on analysis of underlying drivers)	EirGrid (grid operator from Ireland) uses two operational metrics to follow the inertia needs to maintain a stable islanded power system: The first metric is the SNSP (system non-synchronous penetration) limit, it is a measure of the non-synchronous generation on the system at an instant in time. It is the ratio of the real-time MW contribution from non-synchronous generation and net	

	HVDC imports to demand plus net HVDC exports.According to EirGrid, the maximum limit of this parameter for stable operation is between 70 and 80%. The second metric is the ratio of available kinetic energy in the power system to the loss of the largest power infeed. It should be higher than 30 s to ensure stability.
Proposition of solutions to secure inertia	For eastern and south-eastern **Australia**, the measures to secure inertia are: If the power generation from the RES is between 0 and 1200 MW, then 3 SGs must be online. If the power generation from the RES is greater than 1200 MW, then 4 SGs must be operated. For **GB (National Grid):** • Use of thermal power plants in a low load or synchronous condenser mode. • Use of wind turbines, PV plants, and energy storage to respond quickly, to provide enough headroom for the SG to operate (possible by de-loading of RES) • The development of new synchronous energy storage systems, such as compressed air energy storage (CAES) to provide inertial response services in the same way as existing pumped hydroelectric plants • Use of electric vehicles to offer inertia by demand-side management The study compares two inertia emulation control techniques for wind turbines. With the technique of **hidden inertia emulation** done by extracting the kinetic energy from the rotor, the concerns are the sudden dip in the frequency in the recovery process and some stability issues. With the **Fast Power Reserve**, done by changing the operating point to sub-optimal point. The concerns are that it is difficult to predict the reserve power and that the utilization factor of wind turbine is degraded in normal operating cases.
Technologies that are foreseen to provide inertia	Some technologies that can enhance inertia are: • Synchronous condensers • Demand-side management. The relays in the self-regulating loads would operating depending on the ROCOF. • Pumped hydroelectric energy storage (PHES) • Compressed air energy storage (CAES) • Flywheel • Batteries and ultra-capacitors The study mentions the different types of virtual synchronous generators (VSGs): • Inducverter • Synchronous power controller • Virtual synchronous machine (VISMA) • VSYNCH's VSG • Synchronverter
Cost estimations	*No cost estimation provided*
Reviewer's comment	

This paper goes into details about the different types of virtual synchronous generators (VSGs). The paper mixes inertia and FFR response (i.e. prop to RoCoF in the first 500 ms and prop to frequency afterwards)

8.2.18. State Grid Jiangsu Electric Power Company, "Analyzing the inertia of power grid systems comprising diverse conventional and renewable energy sources", 2022

<table>
<tr><th colspan="3">Title: Analyzing the inertia of power grid systems comprising diverse conventional and renewable energy sources</th></tr>
<tr><td>Institution: State Grid Jiangsu Electric Power Company Ltd.</td><td colspan="2">Authors: Qiang Li, Bixing Ren, Weijia Tang, Dajiang Wang, Chenggen Wang, Zhenhua Lv</td></tr>
<tr><td>Date Published: November 2022</td><td>Pages: 11</td><td>Document Type: Scientific paper</td></tr>
<tr><td colspan="2">Keywords: Renewable energy sources, Inertia response, Virtual inertia control, Frequency stability</td><td>Link: https://www.sciencedirect.com/science/article/pii/S2352484722024064</td></tr>
<tr><td colspan="3">Abstract:
The global pursuit of low-carbon technologies has led to the rapid development of renewable energy sources (RES), such as wind and solar power. The large-scale integration of RES into power grid systems can change the characteristics and forms of the system inertia. RES-heavy power systems exhibit lower inertia, compromising their frequency stability and rendering traditional inertia response mechanisms and analysis methods insufficient. This review compares the different inertias in traditional and future RES-heavy power systems, details the inertia response mechanisms of various types of devices, identifies deficiencies in the traditional inertia index when quantifying the inertia response capabilities of the equipment, and illustrates the necessity of exploring a generalized inertia index suitable for such systems. Furthermore, the influence mechanism of system inertia on frequency stability is analysed, and the action mechanism and response time sequence of various types of devices in the system inertia response are described. The challenges in applying the traditional frequency stability analysis method to future RES-heavy power systems are also identified. This review can serve as a guide for developing power grid control systems and analysis methods to accommodate the increasing application of RES.</td></tr>
<tr><th colspan="3">Characteristics of the power system involved</th></tr>
<tr><td>Geographical area: Jiangsu, China</td><td>Size: 46,2 million energy consumers</td><td>Interconnection level:</td></tr>
<tr><th colspan="2">Type of solution considered</th><td></td></tr>
<tr><th colspan="3">Analysis of the publication according to proposed focus areas</th></tr>
<tr><td>Key challenges related to inertia</td><td colspan="2">Power security issues caused by the lack of inertia in the power systems with high RES penetration have gradually emerged in recent years. For example, in 2016, a nearly 10-h power outage occurred in South Central Australia, resulting in a 1.83 GW loss. In 2019, a large-scale power outage of up to 1.5 h occurred in the United Kingdom, resulting in approximately 5% loss of the total loads.
The inertia of a future RES-heavy power system has various forms and response characteristics; after the disturbance, the system inertia is affected by operating conditions, controller parameters, and other factors, showing nonlinear and time-varying characteristics.</td></tr>
</table>

	The uneven distribution of inertia within a system with high RES penetration will be significant and will influence its frequency characteristics.
Main drivers of inertia needs	A power system connecting many RES and other power electronic equipment typically exhibits a significantly different inertia than a traditional synchronous power system in terms of form and response characteristics. The inertia of SGs only depends on the physical structure of their rotating parts and remains constant. By contrast, the inertia provided by power electronic equipment is primarily affected by its control structure and parameters and is time-varying. 2 types of inertia in traditional power system: • Inertia from SGs: the SGs can instantaneously release the kinetic energy stored in the rotor to prevent the rapid drop in system frequency. • Inertia from loads: the energy stored in the electromagnetic fields and rotating masses of the system loads, such as asynchronous motors, change to resist the change in the system frequency; this is called the load inertia effect. As the power system frequency stability gradually deteriorates with increasing RES penetration, the static load voltage characteristic becomes more significant for mitigating the frequency change. Changes in node voltage led to corresponding changes in the power of constant impedance and current loads, reduce the unbalanced power, and reduce the RoCoF. **Inertia in a future RES-heavy power system:** Wind turbines are connected to the grid through power converters that decouple them from the system, preventing them from providing inertia. PV generators require power electronic inverters for grid integration and are decoupled from the system; thus, they cannot provide an inertia response. Therefore, a high contribution of RES to power generation will result in a power grid with a severe lack of inertia.
Considerations related to national needs due to potential splits	*Not addressed.*
Evolution of inertia needs (based on analysis of underlying drivers)	It is assumed that inertia requirements will increase as the share of RES increases, but this is not demonstrated here.
Proposition of solutions to secure inertia	The inertia of a future RES-heavy power system includes the SG, asynchronous motor, and VSG virtual inertias (which all share rotational inertia response characteristics). It also includes the virtual inertia provided by the additional frequency control techniques and equivalent inertia provided by the static load voltage characteristics. In a future RES-heavy power system, the inertia response should use those various devices considering time response of each device.

Technologies that are foreseen to provide inertia	To solve the problem of low inertia in a future RES-heavy power system, previous research has attempted to use energy buffer structures to actively respond to a power imbalance and provide inertia for the system through virtual inertia control techniques. These techniques can be divided into:
	• additional frequency control
	    o virtual inertia control of wind turbines,
	    o DC-link capacitors,

	◦ Energy storage devices (supercapacitors and batteries), • virtual synchronous generator (VSG) based on several virtual inertia control topologies.
Cost estimations	*No cost estimation provided.*
Reviewer's comment	
A good article that succinctly but clearly presents the problem and the associated issues. The review summarized the various types of inertia response mechanisms in future RES-heavy power systems, analysed the influence mechanism of system inertia on frequency stability, and identified challenges faced when using existing traditional inertia response systems and analysis methods to evaluate the power grid system stability.	

8.3. Analysis of five historical system splits

Event	Separation of Italy (2003)	System Separation of 2006	Turkey System Separation (2015)	Separation of Balkan Peninsula (2021)	Separation of Iberian Peninsula (2021)
Event	A disconnected transmission line couldn't be reclosed. This caused an overload on another line and a separation of Italy from the system.	Significant East-West power flows resulted in the tripping of several high-voltage lines, starting in Germany	A transmission line between Western and Eastern Turkey tripped on overload. As a result, the Eastern and Western Turkish subsystems were separated. The Western subsystem, with a pre-disturbance load of 21870 MW and import from Bulgaria of around 500 MW, underwent a power deficit of 4700 MW (i.e. 21%). This sudden imbalance caused the loss of synchronism with the CE power system and the separation from it by tripping of the three interconnection lines with the Bulgarian and Greek grids	The Continental Synchronous Area in Europe was separated into two areas (the north-west area and the south-east area) due to the tripping of several transmission network elements. The system separation resulted in a deficit of power in the north-west area and a surplus of power in the south-east area.	The Continental Europe (CE) Synchronous Area was separated into two areas due to cascaded trips of several transmission network elements. Specifically, the Iberian Peninsula was separated from the rest of CE.
Consequences	Blackouts in Italy (ranging from 3 hours to more than 10 hours in different parts of Italy)	15 million households were affected by interruptions of supply. Resynchronisation of the system was completed in 38min and a	Widespread blackout in Turkey with more than 70 million people without electrical power		

		normal situation in all counties re-established in 2 hours			
Frequency deviations	Due to the imbalance between generation and loads, frequency in Italy fell below 47,5 Hz, resulting in the tripping of the generating units that were still in operation but with the consequent unavoidable loss of load.	Frequency in the Western Island dropped at about 49 Hz. Frequency in the North East area rose to 51,4 Hz in the peak. Frequency in the South East area decreased to about 49.7 Hz.	The Eastern power excess area started accelerating up to 52.3 Hz. The Western area experienced a frequency as low as 48.4 Hz.	In the South-East area, the frequency rose to 50,6 Hz. In the North-West area, the frequency dropped to 49,74 Hz.	
Volume of power flows at the interface at the time of the split	6,6 GW	Between Western Europe and North-East Europe: **9,26 GW** Between Western Europe and South-East Europe: **0,48 GW** Between South-East Europe and North-East Europe: **0,75 GW**	**4,7 GW**	**5,8 GW**	**2,5GW**
Volume of generation that tripped	Almost 11 GW of generation tripped in Italy.	10,9 GW of generation tripping in the Western Island 6,2 GW of wind generation tripped in the North-East island	After the system split, in the East Island approximately 14000 MW of generation was lost due to over frequency.	3,292 MW of generation tripped unexpectedly in the South-East area. Due to incorrect frequency protection settings, in total 620 MW of generation tripped in the North-West Area.	Approximately 3,7 GW of generation tripped. 2,7 GW in Spain and 1 GW in Portugal.
Volume of load shedding	The load shedding plan worked properly, even though as a matter of fact the load available, at the moment of the separation, turned out to be less than 10 000 to 11 000 MW (excluding pumps).	17 GW of load was shed in the Western island (+1.6 GW of pumps).	4.8 GW of load was shed in the Western Island, 2.3 GW in the Eastern Island.	Approximately 0,3 GW of load was shed.	The total amount of load shedding was 4,306 MW (3,561 in Spain, 680 in Portugal and 65MW in France).

9. Annex – Basic concepts related to inertia

This Annex explains basic concepts related to inertia, that are used throughout the report. The starting point is usually the swing equation of a synchronous generator. Using the law of conservation of energy, it can be written first:

$$\frac{dW_K}{dt} = P_m - P_e \tag{1}$$

where $W_K = \frac{1}{2}J\Omega^2$ is the kinetic energy stored in the rotating mass of the generator (turbine + rotor of the synchronous machine), J is the combined moment of inertia of generator and turbine (kg.m²), Ω is the angular velocity of the rotor (mech. rad/s), P_m is the mechanical power provided by the turbine to the rotor, and P_e is the electrical power provided by the synchronous machine to the grid. Because there is a proportionality factor between the angular velocity of the rotor Ω and the frequency f, the kinetic energy can be reformulated as follows:

$$W_K = W_K^0 \left(\frac{\Omega}{\Omega_0}\right)^2 = W_K^0 \left(\frac{f}{f_0}\right)^2 \tag{2}$$

where Ω_0 and f_0 are the nominal mechanical speed and frequency, respectively, and W_K^0 is the kinetic energy of the machine when spinning at the nominal frequency. Equation (1) then becomes

$$\frac{2fW_K^0}{f_0^2}\frac{df}{dt} = P_m - P_e \tag{3}$$

When the frequency stays close to its nominal value ($f \cong f_0$), it can be approximated as follows:

$$\frac{2W_K^0}{f_0}\frac{df}{dt} = P_m - P_e \tag{4}$$

It is then common for the swing equation of a synchronous machine to express it in per unit, by introducing the per unit inertia constant (expressed usually in seconds):

$$H = \frac{W_K^0}{S_n} \tag{5}$$

where S_n is the nominal (apparent) power of the machine. By normalizing the power imbalance $\Delta P = P_m - P_e$ also by S_n (i.e. $\Delta P_{pu} = \Delta P/S_n$) and the frequency by its nominal value ($f_{pu} = f/f_0$), equation (4) becomes in per unit:

$$\frac{df_{pu}}{dt} = \frac{\Delta P_{pu}}{2H} \tag{6}$$

This equation shows that the Rate of Change of Frequency (RoCoF) following a power imbalance for an isolated synchronous generator is inversely proportional to its inertia constant. In other words, the inertia of a synchronous generator, that can be expressed by its inertia constant H, expresses the resistance to a change in frequency resulting from an imbalance between mechanical and electrical power.

These equations can be extended to an interconnected (multi-machine) system by summing equation (4) for all the n machines, and by defining the frequency at the centre of inertia by

$$f_{COI} = \frac{\sum_{i=1}^{n} W_{K,i}^0 f_i}{\sum_{i=1}^{n} W_{K,i}^0} = \frac{\sum_{i=1}^{n} W_{K,i}^0 f_i}{W_{K,sys}^0} \tag{7}$$

where $W_{K,i}^0$ is the kinetic energy of machine i when spinning at the nominal frequency and f_i is its actual frequency, and $W_{K,sys}^0$ the total kinetic energy of the system at the nominal frequency. The swing equation for the system becomes then

$$\frac{2W_{K,sys}^0}{f_0}\frac{df_{COI}}{dt} = P_G - P_L \tag{8}$$

where P_G is the total generation and P_L the total load. This equation shows that, for a given imbalance between the load and the generation, the RoCoF will be inversely proportional to the total kinetic energy of the system. This last equation is sometimes also given in per unit, by normalizing the total kinetic energy and the power imbalance ΔP by a system base S_{sys}. However, such a normalization can be confusing, for various reasons. First, several possibilities exist to define S_{sys}. It could be the total (synchronous) generation capacity connected to the system, the total installed (synchronous) generation capacity, the load, the peak load, etc. Often, when the inertia of the system is normalized and expressed in seconds, the choice of the system base is not explained, which makes the results very difficult to understand. Second, the normalization can give a wrong idea about the capability of a system to withstand power imbalances while keeping the RoCoF to a low value. For instance, if the peak load is used as a power basis, an inertia of 1 s and a power imbalance of 1 GW would lead to a RoCoF lower than 0.1 Hz/s for Continental Europe, but higher than 4 Hz/s for Ireland. For these reasons, it is strongly recommended to avoid the use of a reduced inertia constant H (in seconds) for a system. The total equivalent kinetic energy (in GW.s or GJ) should be used instead to quantify the inertia of a system (It is named “equivalent” because grid-forming converters do not store kinetic energy as synchronous generators but reproduce their behaviour). This is what is done in this report.

Getting in touch with the EU

In person

All over the European Union there are hundreds of Europe Direct centres. You can find the address of the centre nearest you online (european-union.europa.eu/contact-eu/meet-us_en).

On the phone or by email

Europe Direct is a service that answers your questions about the European Union. You can contact this service:

— by freephone: 00 800 6 7 8 9 10 11 (certain operators may charge for these calls);

— at the following standard number: +32 22999696;

— via the following form: european-union.europa.eu/contact-eu/write-us_en.

Finding information about the EU

Online

Information about the European Union in all the official languages of the EU is available on the Europa website (european-union.europa.eu).

EU publications

You can view or order EU publications at op.europa.eu/en/publications. Multiple copies of free publications can be obtained by contacting Europe Direct or your local documentation centre (european-union.europa.eu/contact-eu/meet-us_en).

EU law and related documents

For access to legal information from the EU, including all EU law since 1951 in all the official language versions, go to EUR-Lex (eur-lex.europa.eu).

Open data from the EU

The portal data.europa.eu provides access to open datasets from the EU institutions, bodies and agencies. These can be downloaded and reused for free, for both commercial and non-commercial purposes. The portal also provides access to a wealth of datasets from European countries.

Publications Office
of the European Union