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Challenges and opportunities of inertia estimation and forecasting in low-inertia power systems

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ABSTRACT

Accurate inertia estimates and forecasts are crucial to support the system operation in future low-inertia power systems. A large literature on inertia estimation methods is available. This paper aims to provide an overview and classification of inertia estimation methods. The classification considers the time horizon the methods are applicable to, i.e., offline post mortem, online real time and forecasting methods, and the scope of the inertia estimation, e.g., system-wide, regional, generation, demand, individual resource. The framework presented in this paper facilitates objective comparisons of the performance of newly developed or improved inertia estimation methods with the state-of-the-art methods in their respective time horizon and with their respective scope. Moreover, shortcomings of the existing inertia estimation methods have been identified and suggestions for future work have been made.

1. Introduction

Sufficient inertia in power systems is crucial to ensure secure and reliable power supply. In traditional power systems, inertia was provided by the rotating masses of synchronous generation and motor loads. These days, inertia is decreasing due to the massive introduction of converter-interfaced generation, consumption and transmission of power, which causes challenges to maintain acceptable frequency profiles. Inertia has been specifically low during periods of low demand and high renewable production [1]. To deal with the challenges of reduced inertia levels, system operators would benefit from accurate estimates or measurements of the inertia available in the system at each point in time as well as from forecasts of expected inertia levels [2]. In today's operational practice, system operators estimate system inertia based on part of the resource [2] or based on a simplified empirical relation [3], which are approximate methods. However, considering the evolution of power systems towards lower inertia levels, it is crucial to have reliable and more accurate methods to estimate instantaneous and forecast future inertia.

Given the importance of accurate inertia estimation for the reliable and secure operation of future low-inertia power systems, research into inertia estimation methods is an ongoing field of study. A large literature on inertia estimation methods is available, but the existing methods have not yet been classified or categorized, which hampers an objective assessment and comparison of newly developed inertia estimation methods. Existing review papers in the field of low-inertia power systems have focused on (i) the role and control of technical inertia enhancement techniques involving converter-interfaced energy buffers, also denoted as virtual inertia or inertia emulation [4–8], (ii) a general overview of the relevance of inertia in power systems by looking at the different sources of inertia and their impact on the operation of power systems [9] and (iii) a broad survey of the issues related to low-inertia power systems as well as the solutions that have been put forward with a particular focus on transient and frequency stability and converter control [10].

To facilitate the improvement of existing and development of new inertia estimation methods, this paper presents a framework allowing researchers to easily classify their method and identify the state-of-the-art in the respective class. In this respect, the presented framework allows for an objective comparison of the performance of improved or newly developed methods, which becomes more and more important when moving towards low-inertia systems of which the operation relies upon accurate inertia estimates and forecasts. We surveyed the literature on inertia estimation and forecasting methods and categorized the approaches according to the applicable time horizon and the scope of the inertia estimates. This enabled us to discuss the evolution in the development of inertia estimation and forecasting methods with relation to the operational practice and to identify challenges and shortcomings of

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the existing methods in the light of the current operational practice and future low-inertia systems. Moreover, pathways for future research in the field of inertia estimation and forecasting methods have been put forward.

The paper is structured as follows. Section 2 discusses the operational practice with respect to inertia, pinpointing specific aspects of the operational practice in different countries. Section 3 introduces the methodology to classify the state-of-the-art inertia estimation and forecasting methods. Section 4 classifies the methods according to the time horizon of interest, whereas Section 5 classifies the methods according to the scope of the estimation. Section 6 concludes the paper and gives an outlook into important directions for future research.

2. Operational practice with respect to system inertia

Secure and reliable operation of power systems requires a frequency that is nearly constant around the nominal frequency, which equals 50 Hz in most parts of the world and 60 Hz in the Americas and some parts of Asia. Grid codes prescribe acceptable frequency deviations and the system operator should take adequate actions to satisfy these limits. Inertia is a crucial parameter to satisfy the frequency limits in today's power systems.

2.1. Operational constraints

The frequency deviates due to imbalances between demand and supply ΔP as characterized by the swing equation[1]:

$$2 \cdot H \cdot \frac{d\Delta \bar{f}}{dt} + K^D \cdot \Delta \bar{f} = \frac{\Delta P}{S^{base}} \tag{1}$$

where H is the system inertia constant [s], $\Delta \bar{f}$ the relative frequency deviation from the nominal frequency [pu], K^D the damping coefficient [%], i.e., the percent change in system load per percent change in grid frequency (This constant varies between 1 and 3% across different power systems and is about 2.5% for the Great Britain system [12]) and S^{base} the base power [MVA]. Fig. 1 shows a typical frequency response after a power imbalance.[2]

Grid codes put limits on the rate of change of frequency (ROCOF) $\frac{d\Delta \bar{f}}{dt}$ and the frequency nadir f^{min} to avoid tripping of protection relays. Generating units' protection relays are configured to avoid generating units to be exposed to ROCOF ranges from 1.5 to 2 Hz/s (over a 500-ms rolling window) that can cause pole slipping and catastrophic failure [14]. Also anti-islanding protection may be designed based on the detection of ROCOF [15]. Frequency nadir is limited to avoid tripping of underfrequency load shedding protection relays. Fang et al. provide an overview of the ROCOF and frequency nadir limits in different power systems around the world [6].

Power system inertia is an important instrument to limit the ROCOF and frequency nadir. In its elementary form, inertia is defined as the resistance of a physical object to a change in its state of motion, including changes in speed and direction [13]. In a power system context, inertia can be understood as the resistance, in the form of any kind of energy exchange, to counteract the changes in system frequency resulting from power imbalances in generation and demand [13]. In the Great Britain system, the inertial response has been defined originally as the period up to 1 s immediately following a loss of generation or demand prior to the activation of primary frequency response services [16]. Traditionally, the inertial response combined with the droop response of the primary frequency control has limited the frequency nadir after a disturbance. The frequency restoration has further been accomplished by the secondary and tertiary frequency control. Rebours et al. provide an overview of the technical features of the primary, secondary and tertiary frequency control reserves in different power systems [17]. Recently, system operators of several low-inertia systems worldwide have introduced fast frequency response products that require response to a frequency deviation within 1–2 s [18].[3] These services have the objective to keep the frequency nadir within limits during disturbances, which cause increased ROCOF and larger frequency swings in low-inertia systems.

2.2. Contributors to the power system inertia

Inertial response[4] E_t^I consists of two main contributors: the kinetic energy in rotating masses that are synchronized with the power system $E_t^{I,sync}$ and virtual inertia from convertor-interfaced generation $E_t^{I,VI}$:

$$E_t^I = E_t^{I,sync} + E_t^{I,VI} \tag{2}$$

The nature and size of the available inertial response in the power system has been changing over the last decade. Originally, rotating masses of synchronous machines, both generation $E_t^{I,gen,sync}$ and load $E_t^{I,load,sync}$, exchange kinetic energy with the system in the case of a power imbalance by slowing down or speeding up:

$$E_t^{I,sync} = E_t^{I,gen,sync} + E_t^{I,load,sync} = E_t^{I,SO,sync} + E_t^{I,emb,sync} \tag{3}$$

Part of the inertia contribution of synchronous units is monitored by the system operator $E_t^{I,SO,sycn}$ and part is out of sight of the system operator, embedded in the distribution system $E_t^{I,emb,sync}$. This exchange of kinetic energy impacts the system frequency as the rotor speed is proportional to the frequency in the system. The inertial response of the synchronous rotating masses is instantaneous. In today's power system, synchronous machines have been gradually replaced by converter-integrated generators and demand. Moreover, power-electronic-interfaced high voltage dc technology has been increasingly used for interconnectors between power systems. These technologies can offer inertial response if they have an adequate energy buffer and control system in place. The control system should regulate the release and absorption of energy similar to the inertial response of synchronous generation units. Fang et al. give an overview of the emerging techniques for inertia emulation with different sources of energy storage [6]. The penetration of inertia emulation in power systems has been limited so far. First of all, appropriate regulation has not yet been in place. Second, the system's dynamic characteristics will be impacted as control characteristics of inertia emulation techniques differ compared to synchronous generators' behaviour in case of disturbances [10,19]. Third, emulated inertial response typically comes from more variable and uncertain energy buffers, which increases uncertainty and variability in system operation [20,21]. The reduction of synchronous rotating masses implies that traditional, instantaneous inertial response in modern

[1] This is the linearised version of the swing equation, which is valid for normal oscillations in power systems [11].

[2] The frequency response in Fig. 1 gives the frequency evolution at the centre of inertia (COI). The frequency at the centre of inertia is a theoretical concept representing the inertia weighted frequency of all generators in the system and cannot be measured directly in the system. Calculating this value would require individual frequency measurements for all generators. Instead of estimating the frequency at the COI online, system operators typically measure the frequency at a relevant pilot node in the system. However, frequency measurements should be done with care, as they are heavily influenced by the location of the measurement and neighbouring generators [10].

[3] Whereas inertial response is triggered by the rate of change of frequency, frequency response services respond to a frequency deviation.

[4] The system inertia constant H defined in Eq. (1) can be derived from the inertial response as: $H_t = \frac{E_t^I}{S^{base}}$, with E_t^I the inertial response at time t [MVAs] and S^{base} a power base defined for the system [MVA]. To avoid the definition of a common power base, the inertial response is commonly defined in energy units [MVAs].

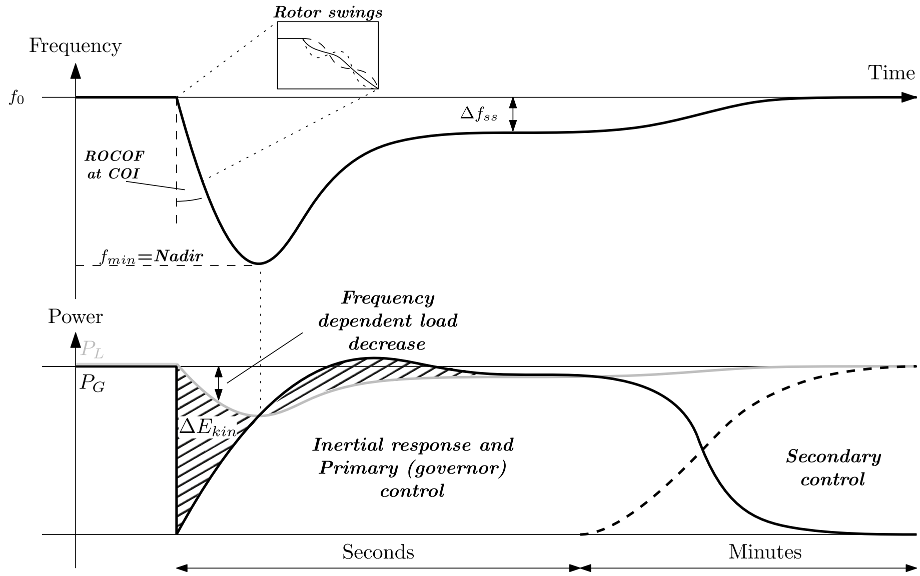

Fig. 1. Frequency response after a power imbalance [Figure from Ref. [13], used with permission from the author].

power systems has been declining and tends to reduce even further in the future.[5]

2.3. Operational measures to limit the risk of ROCOF and underfrequency relay tripping

Reduced instantaneous inertial response increases the risk of tripping ROCOF-based loss of main protections of embedded generators and underfrequency load-shedding relays. Besides changing grid codes in terms of connection criteria for non-synchronous generation [22] or modifying protection relay settings to cope with higher ROCOF and larger frequency swings [23,24], operational measures can be taken to reduce this risk. Considering the different terms in the swing equation (Eq. (1)), the system operator can reduce the risk of tripping ROCOF protection relays by reducing the power imbalance ΔP, i.e., by reducing the possible largest loss of generation or consumption in the system, or by increasing the inertial response, represented by the inertia constant H. Fig. 2 gives an overview of the operational practice with respect to inertia for the case of Great Britain.

Reducing the possible largest loss requires the system operator to redispatch generation or interconnection flows ahead of real time. Adequate redispatch relies, amongst others, upon an accurate estimation of the possible largest loss in the system. In the Nordic area, system operators have implemented a tool in their SCADA system to estimate the possible largest loss of generation or consumption in an online way [25]. In Great Britain, the system operator is informed by the expected output of the balancing mechanism units, which include the largest generating units, from 11:00 day ahead for each 30-min settlement period of the next day via the physical notifications. The grid code of Great Britain defines physical notifications as “a series of MW figures and associated times, making up a profile of intended input or output of active power at the grid entry point or grid supply point, as appropriate” [26]. Large generator units, interconnectors and large demand units should provide these physical notifications. They should update their physical notifications throughout the day if significant changes are to be expected [26]. One hour ahead of real time, the final market settlement is reported to the system operator and the balancing mechanism starts. During the balancing mechanism, the system operator can accept bids and offers of the balancing mechanism units and request them to increase or decrease their power output. In general, system operator’s decisions upon generator redispatch are not only affected by economic concerns, but should also respect generators’ reported ramp rate limits, minimum run time and the time taken to synchronize, as well as network constraints while being practicable for the system operator, e.g., large volumes of energy are preferred to reduce the number of instructions. Nowadays, reducing the largest loss is typically 10 times cheaper than increasing the inertial response by bringing additional generators online in Great Britain [27]. However, its effectiveness in power systems with a reduced number of large synchronous generator units and more smaller, distributed generation units, which are highly variable and uncertain in nature, is questionable.

To increase system inertia, the system operator can replace large amounts of converter-interfaced generation with synchronous generation ahead of real time. If additional synchronous generators need to be brought online, the system operator should take into account the time to synchronize the power plant. In Great Britain, the system operator has the possibility to start up balancing mechanism units that are not expected to run according to the physical notifications via the balancing mechanism start up ancillary service at the price of a start-up and hot-standby payment [28] or using forward trading. These actions can be initiated before the balancing mechanism starts. In Ireland, a synchronous inertial response product has been introduced to contract units to provide inertia [29]. Alternatively, markets for inertia, which enable the trade of virtual inertia from converter-interfaced resources, have been suggested in the literature [30,31].

On top of the inertial response and the reduction of the power imbalance, preventing the tripping of underfrequency-load-shedding relays can benefit from frequency response services, especially fast frequency response services in low-inertia systems. Studies in the Nordic area have identified fast frequency reserves as the solution to the Nordic inertia challenge [25]. Also in Great Britain, these faster-acting frequency response services are crucial to ensure frequency containment within operational limits and avoid underfrequency load shedding with

[5] In the extreme case of 100% non-synchronous systems, natural response to power imbalances is no longer present in the system and frequency is no longer a measure of power imbalance [10]. Although the viability of control and operation of zero-inertia power systems has been proven in simulation studies and practical experiments, their practical implementation will not be for tomorrow, as many existing grid-connected devices and machines expect frequency to change relatively slowly and further study is required to integrate new converter technology into existing power system structures [19]. Milano et al. expect that substituting all conventional power plants with converter-interfaced generation will take a few decades [10].

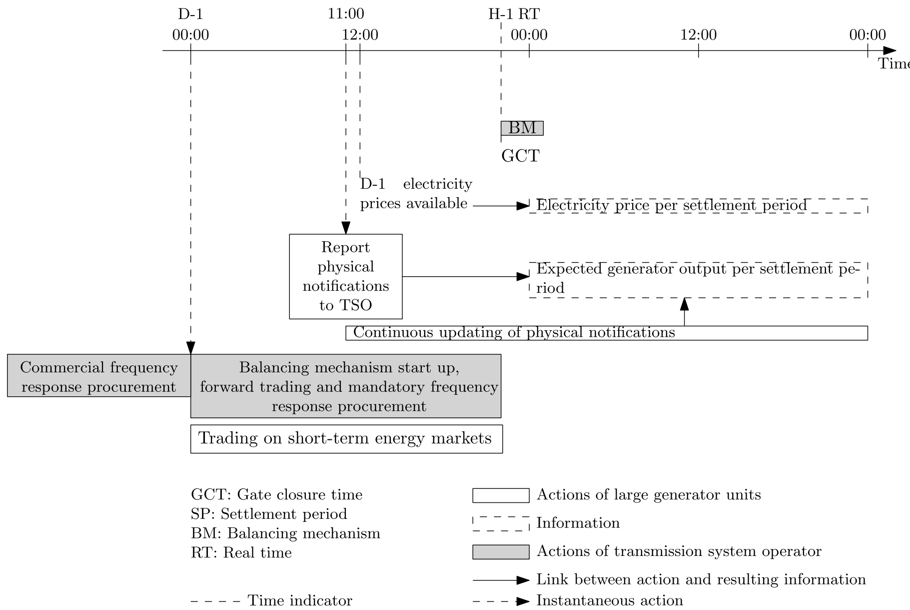

Fig. 2. Overview of the operational practice related to inertia for the case of Great Britain.

relaxed ROCOF limits [1].[6] The system operator should adequately contract and procure frequency response services on different time scales ahead of real time. The market arrangements to contract frequency response services vary with the specific service and between different geographical regions, e.g., Nordic area [32], Ireland [33], Great Britain [34].

To make an optimal trade-off between available operational actions, the system operator needs to estimate the inertia to determine the rate-of-change of frequency and the maximal frequency deviation. Nowadays, National Grid ESO builds tables representing the 5-min resolution frequency response requirement as a function of demand, inertia and largest infeed loss using a frequency simulation engine [35]. These tables are used in operational systems to optimise the overall frequency response requirement for 5 min blocks throughout the day. In the Nordic area, system operators create similar lookup tables using a linear regression model that expresses the maximal frequency deviation as a function of the ratio of the power imbalance and the inertial response in the system [36,37]. Fig. 3 illustrate the operating tables that express the frequency response for different values of the largest loss, the system inertial response and the system demand. Ahead of real time, the tables, complemented with forecasts of demand, inertia and largest loss, give insight in the needs for commercial frequency response procurement, inertia increase and redispatch for largest loss reduction. In real time, the tables, combined with the contractual arrangements for generation and frequency response per settlement period, give the control room engineer insight in the residual frequency response requirements that should be procured from mandatory services in real time [27]. In power systems operated by independent system operators, such as in the US, stochastic unit commitment models for simultaneous scheduling of multiple frequency services and dynamic reduction of the largest loss can support a secure operational practice [38].

3. Classification of inertia estimation and forecasting methods

Cost-effective and secure operational decisions require accurate inertia estimates, which enable system operators to estimate the characteristics of the frequency response of the system. Initial approaches to estimate inertia in power systems dominated by synchronous generator units assumed the system inertia to be nearly constant, with an inertia constant of generation of approximately 5 s and an inertia constant of demand in the range of 1.6–1.8 s [39]. To consider the variability of the inertia level in power systems with reduced synchronous generator units, increased embedded units and uncertain and variable renewable energy resources, alternative inertia estimation methods have been developed that combine measurements of system variables, such as frequency and active power, and the physical model of the frequency profile as defined by the swing equation introduced in Eq. (1). The system inertia is considered as a parameter to be estimated in a parameter estimation or system identification method. Inertia estimation methods in the literature can be categorized according to the time instant they are estimating the inertia for and according to the scope of the method. Table 1 classifies the methods presented in the literature row-wise according to the time horizon and column-wise according to the scope. This classification facilitates to easily identify the state of the art in each class, which allows for objective comparisons of the performance of new or improved inertia estimation methods with the state-of-the-art methods in the respective class.

4. Classification of inertia estimation methods according to the time horizon of interest

Inertia estimation methods can be categorized based on the time horizon of interest as offline post-mortem approaches, online real-time approaches and forecast approaches. Post-mortem inertia estimation methods are applied, for instance, in an analytical context to make an ex-post assessment of the inertia level in the system during large disturbance events. Real-time methods aim at making an instantaneous estimate of the inertia based on readily available measurements of system variables. Forecast approaches estimate the inertia to be expected in the future.

4.1. *Offline, post-mortem inertia estimation*

Post-mortem, disturbance-based approaches to estimate total system inertia were the first attempts to improve the modelling-intensive approach in Ref. [39] to estimate the frequency response profile. Post-mortem approaches estimate the inertia after large frequency

[6] National Grid is currently in the process of replacing the traditional primary, secondary and tertiary frequency response services with a new integrated suite of services [1].

	Demand$_1$				Demand$_n$		
	E_1^I	E_2^I	E_k^I		E_1^I	E_2^I	E_k^I
ΔP_1	$ROCOF^{max}$ and Δf^{max} for each combination			ΔP_1	$ROCOF^{max}$ and Δf^{max} for each combination		
ΔP_2				ΔP_2			
ΔP_j				ΔP_j			

Fig. 3. Illustration of the tables used in system operation that express the frequency response for different values of the largest loss, the system inertial response and the demand in the system.

Table 1
Overview and classification of inertia estimation methods according to time horizon and scope.

	Scope					
	System	Zone	Synchronous generation	Embedded generation	Clustered generators/Node	Demand
Offline, post-mortem	[16,40–44]	[45]	[46]	[47,48]		[46,49]
Online, discrete	[50–52]	[3,53,54]	[55–59]	[60]	[61]	
Online, continuous	[62]	[63]	[64,65]		[66]	
Forecast	[67,68]	[69]				

References that present a method that is able to estimate the inertia for different scopes are only mentioned once in the table, i.e., in the column of the smallest scope it is applicable to.

disturbance events have taken place for which the power imbalance related to the rate of change of frequency is accurately known. Inoue et al. were the first to introduce such a disturbance-based approach for inertia estimation that combines the swing equation with processed PMU measurements[7] of the frequency and the known size of the disturbance to estimate the total system inertia [40]. They estimate the inertial response as:

$$E^I = \frac{-\Delta P}{2 \cdot \left.\frac{d(\Delta f/f_0)}{dt}\right]_{t=0}} \tag{4}$$

with ΔP the size of the loss and $\left.\frac{d(\Delta f/f_0)}{dt}\right]_{t=0}$ the rate of change of frequency at the starting time of the disturbance.[8] This approach estimates the combined contribution of synchronous generators, embedded units and demand. Most post-mortem, disturbance-based approaches ignore the damping and the short-term frequency response services in the imbalance ΔP applied in the swing equation, by assuming it to be zero in the short time period immediately after the disturbance [41,48]. Especially with the introduction of new, fast frequency response services, which reduce the time window of pure inertial response, this assumption may become challenging. Including activated frequency response services, such as governor response, and frequency and voltage dependent characteristics of the load in the modelling of the power imbalance is a way to deal with this issue, such as in Refs. [42,44]. This approach also facilitates the simultaneous estimation of the system inertia constant and the size of the disturbance considering the frequency- and voltage-dependent dynamics using parameter estimation that relies upon solving a system of linear equations in Ref. [42] or an optimization in Ref. [44].

Three aspects are specifically affecting the accuracy of post-mortem approaches. First of all, the size of the loss should be accurately known. For this reason, not all events may be suitable for use in post-mortem inertia estimation. Ashton et al. mention the difficulty of estimating the inertia after events with multiple sequential outages of generators and suggest to focus on instantaneous events, which may be detected by their modified detrended fluctuation analysis [43]. Second, the on-set of the event, i.e., t = 0, should be accurately determined. A recently suggested technique in the literature estimates the event on-set based on the second derivative of the ROCOF [75]. Third, the accuracy of the ROCOF calculation is affecting the accuracy of the inertia estimate. ROCOF has to be estimated on the relevant time interval, i.e., between the on-set of the event and the on-set of primary frequency response. The latter is determined by the time constant of the governors in traditional frequency response and is typically between 1 and 2 s following an infeed loss [16]. The oscillatory component in the frequency signal produced by the synchronizing power between the generators may cause erroneous results for the ROCOF calculation. To overcome this issue, Inoue et al. fitted a polynomial to the frequency signal to extract the frequency signal and smooth the transients [40,41,46], whereas Ashton et al. used a 0.5 Hz low-pass filter to filter the frequency signal after finding the fitting of a polynomial to the signal insufficient [16]. Besides the oscillations, ROCOF calculations may be corrupted by noise, which is filtered using moving average filters [40] or modified detrended fluctuation analysis [16,43] in the state-of-the-art techniques. Also the location of the frequency measurements relative to the in-feed loss affects the ROCOF calculation. For an identical event, a measurement from a weakly interconnected part of the system with low local inertia results in a higher estimated value of the ROCOF compared to an estimate based on a measurement from an electrically strong part of the network with a relatively high inertia [16].

Post-mortem approaches to estimate inertia have three important drawbacks in low-inertia systems with a high penetration of renewable

[7] PMUs can measure voltage and currents phasors in the system, as well as frequency, rate of frequency change, active power output of generators and power flows on transmission lines with measurement rates of 30–60 measurements per second [70,71]. PMUs have the capability to directly monitor load feeders, but this is typically not the priority. The capability of PMUs to support inertia estimation depends on the noise and response delay on a step change [72]. Also the locations of the PMUs impact the frequency measurement. Some methods use averaged frequency measurements of the PMUs to circumvent location specific frequency swings [73].

[8] $\Delta f = f(t = 0s) - f_0$ with f_0 the nominal system frequency and t = 0s the onset time of the disturbance. The rate of change of frequency is typically calculated as the change in frequency over a 0.5 s time period immediately following the onset of the disturbance $\left.\frac{d(\Delta f/f_0)}{dt}\right]_{t=0s} = \frac{[f(t=0.5s)-f(t=0s)]/f_0}{0.5s}$ [74].

energy sources. First of all, reduced inertia levels increase dynamic behaviour (small signal and transient), which hampers the accuracy of post-mortem inertia estimation approaches. Second, post-mortem approaches can only determine the inertia at discrete time instants, when a large disturbance event has occurred. As large disturbance events occur rarely, post-mortem approaches do not result in continuous inertia estimates. Inertia estimation methods with low temporal resolution are expected to become less reliable in the future due to the increasing variability of inertia in the system. Keeping a data base of accurate inertia estimates during large frequency events can support inertia estimation with higher temporal resolution. However, this database is conditional upon the system condition at the moment of estimation, e.g., the amount of synchronous masses available in the system, and cannot necessarily be generalized to a new system condition. Third, the ROCOF calculation is hampered by the reduction of the time constants of the onset of frequency response. Time constants of the onset of frequency response are changing form 1–2 s to within second response due to the integration of very fast frequency response services, such as the enhanced frequency response in Great Britain (response within 1 s for a −0.5 Hz change in frequency) [21,76] or the fast frequency reserve in the Nordic area (e.g., 100% response within 0.7 s for a frequency deviation of −0.5Hz) [25].

4.2. Online inertia estimation

In contrast to post-mortem estimates based on historical data of large disturbance events, real-time estimates use real-time measurements as inputs for the inertia estimation. The real-time estimates provide closer to real time information about the inertia in the system. Three types of real-time inertia estimation methods with different temporal resolutions can be distinguished: (i) estimating the total contribution from transmission-system-connected synchronous generator units as a lower bound on total inertia using information from the supervisory control and data acquisition (SCADA) system or energy management system (lower-bound methods), (ii) close-to-real-time inertia estimation during disturbances based on PMU measurements (discrete methods), (iii) continuous inertia estimation based on PMU measurements or measurements of extensible grid measurement devices (XMU)[9] (continuous methods). Table 2 classifies the real-time approaches according to these three types of methods. The approaches are also classified according to the domain in which the inertia is estimated, i.e., using a time series model, a model in the Laplace domain or a model in the modal domain based on inter-area oscillations.

4.2.1. Total inertia from transmission-system-connected synchronous generation units

Total inertia may be approximated by summing the inertia contribution of transmission-system-connected synchronous generators based on their online capacity and inertia constant:

$$E_t^{I,SO,sync} = \sum_i H_i \cdot P_i^{G,C} \cdot K_i \tag{5}$$

where H_i is the inertia constant of generator i, $P_i^{G,C}$ the power rating of generator i and K_i its status, i.e., whether it is connected to the system or not. The inertia constant of a synchronous generator equals the kinetic energy in the rotating mass at rated speed of the generator E_i^{kin} expressed proportional to the power rating of the generator:

$$H_i = \frac{E_i^{kin}}{P_i^{G,C}} \tag{6}$$

It represents the time in seconds a generator can provide rated power solely using the kinetic energy stored in the rotating mass [79]. Accurate inertia constants of individual generators are not generally known to the transmission system operator [37,80]. Also the equivalent inertia constant of virtual inertia resources is not readily available and possibly variable over time. Research efforts have been focussing on estimating these equivalent inertia constants.[10] On top of the inertia constant, this approach requires knowledge of the status K_i and the generation capacity $P_i^{G,C}$ of the generators. The online status of large transmission-system-connected generators can be monitored in the SCADA or EMS system, while their capacity is known to the system operator. This approach for inertia estimation has been practically implemented in the SCADA systems of TSOs in the Nordic area [37] and is used by National Grid ESO to estimate the inertia contribution of transmission-system-connected synchronous generators [3].

Although the complexity of inertia estimation based on the online capacity of generators is low, the resulting inertia estimate is not accurate, especially in low-inertia systems with an increased share of embedded units in the system. First of all, the approach underestimates the total system inertia that is available, as only generators that are monitored by the transmission system operator are considered in the estimation, whereas small embedded units, such as combined heat and power plants, or small motor loads are typically not considered. Also future providers of virtual inertia not directly monitored by the system operator, such as small renewable energy sources complemented with for instance battery systems, cannot be considered in this estimation, unless adequate communication arrangements are made between system operators and the responsible service providers. In the latter case, the communication of the possibly variable inertia constants of the virtual inertia units is crucial as well. The results of this estimation approach can thus be considered as a lower bound and defines an upper limit on the ROCOF, as not all contributing units are considered in the estimation. Second, the inertia estimates are only available at discrete time instants. They rely upon the monitoring of energy management or SCADA systems. Although the SCADA system samples data at a relatively high frequency of typically 1 Hz, the standard practice is to store 10-min averaged values of the parameters characterising the operating and environmental conditions [81]. To estimate the inertia between two monitoring instants of the generators, a statistical model to estimate the change in inertia from synchronous generators based on measurements of frequency deviation with a higher temporal resolution can be applied [73].

Table 2
Categorization of real-time inertia estimation methods in lower-bound, discrete and continuous methods that apply parameter estimation in time series, Laplace and modal domain models.

	Domain		
	Time series	Laplace	Modal
Lower-bound	[37,73]		
Discrete	[3,50,52,55–57,78]		[45,51,53,54,59,61], [65] [a]
Continuous	[62,64]	[63,66]	[65] [a]

[a] Temporal resolution of the inertia estimates depends on the resolution of the estimation of the inter-area oscillations [65].

4.2.2. Discrete inertia estimation

Inertia estimation methods are available to estimate inertia close to real time during disturbances based on PMU measurements of frequency and estimates of power imbalance. Table 2 indicates two main approaches that can be distinguished in this group of methods: (i) Methods

[9] A comparison of the capabilities of extensible grid measurement devices with PMUs is provided online [77].

[10] These research efforts are indicated in the fourth column of Table 1 and are discussed in more detail in Section 5.2.

that directly work with the time series data and (ii) methods that work in the modal domain and estimate the inertia based on inter-area oscillations. Similar to the offline disturbance-based approaches, the underlying model of these parameter estimation methods is the linearised swing equation, typically ignoring damping and primary and secondary frequency response. The methods assume to estimate the inertia within a very short period after the disturbance before these slower dynamics kick in. Schiffer et al. have included a generator governor model to capture the impact of primary frequency control [50]. Alternatively, applying more detailed system models, including dynamic generator models and power flow equations, enable the inertia estimation based on voltage measurements [60]. However, this comes at an increased computational cost. Bayesian approaches for parameter estimation enable the quantification of the uncertainty on the point estimates of inertia caused amongst others by measurement noise [60].

Real-time disturbance-based inertia estimation is challenging for two reasons. First of all, the online detection of an appropriate disturbance requires attention. Detection based on signals filtered using a moving-average filter is a frequently used technique [52,55]. Second, accurate estimation of the size of the disturbance based on available PMU measurements is challenging. Approaches to deal with this challenge differ with the scope of the inertia estimation method. In methods that estimate the inertia constant of individual generators based on time series of PMU measurements it is frequently assumed that the mechanical power output of a generator equals the electrical power output at the previous time instant [52,55]. This assumption is based on the slow response of a generators mechanical power output compared to the electrical power output and the fact that frequency control balances the mechanical and electrical power within the generator making them approximately equal before a disturbance [56]. Methods to estimate regional inertia, on the contrary, approximate the power imbalance per independent frequency region as the change in power flow on the interconnecting lines during disturbances [3].[11] The latter assumption originates from the inter-area power flow oscillations between independent frequency regions resulting from power imbalances. National Grid ESO is currently testing the approach introduced in Ref. [3] in their system [82].

The performance of disturbance-based inertia estimation methods depends on the size of the disturbance [3]. Originally, only outage events were considered as appropriate frequency events [52]. However, also generator rescheduling at the hour causing frequent, recurring, and scheduled frequency variations have proven to be suitable for real-time inertia estimation [50]. Nevertheless, the temporal resolution of the estimates is still limited to 30–60 min in these cases. At intermediate time instants, values for inertia have to be extrapolated based on the latest estimation [73].

4.2.3. Continuous inertia estimation

(Near-)continuous inertia estimation methods rely upon PMU or XMU measurements of the frequency and continuous estimates of the power imbalance in the system. Based on these two sources of information they estimate inertia in the time domain, Laplace domain or modal domain, as indicated in Table 2. (Near-)continuous methods have an increased temporal resolution compared to discrete inertia estimation methods. However, continuously estimating the power imbalance during normal system operation is hard, as power imbalances in normal operation are small compared to measurement noise and cannot be measured directly with state-of-the-art measurement equipment. Two approaches have been used in the literature to continuously determine the power imbalances in power systems during normal operation. A first approach estimates the power imbalances on a near-continuous basis (in a time scale of minutes or tens of minutes) based on PMU measurements. This method involves strong assumptions and is only valid if generator settings do not change [63]. Second, inertia estimation methods based on microdisturbances may overcome the issue of poor estimation of power imbalance by injecting a known microdisturbance in the system. These microdisturbances may be optimized to maximize the signal-to-noise ratio [66] or the impact on the frequency measurements can be filtered with advanced signal processing [62].[12]

The accuracy and reliability of continuous inertia estimation methods have not been proven so far. Guo et al. have shown that the accuracy of their estimates reduce with larger errors in the measurements and that accurate initial guesses of the inertia constants, which are not straightforward to obtain, are required to ensure the convergence of the algorithm [65]. Also the method of Tuttelberg et al. has shown deficiencies [63]. The results of a case study indicate incorrect inertia estimates at some time instants. One of the reasons for the poor performance may be related to the approximation of the power imbalance in the system. The output of generators and interconnectors are considered to be constant over the measurement period and the measured changes in generation and interconnection flows compared to the start of the measurement period are attributed to power imbalances. It is to be expected that the validity of this assumption decreases with the increasing variability of generation and interconnection flows that comes with the increased penetration of variable renewable energy sources and the introduction of fast response services. Also microdisturbance methods have not been thoroughly validated. Validation of the method in Ref. [62] is performed based on one week of inertia data provided by the British system operator, which are based on an empirical formula. Although the measurements swing around the empirical results, the empirical results do not correspond with the ground truth inertia. It is hard to attribute the swings of the measurements to the stochastic behaviour of inertia or to measurement noise, as values for the ground truth are not available and a reference case for calibration has not been presented. Moreover, it is important to verify the applicability of inertia estimation based on microdisturbances for large and not densely meshed systems with high levels of inertia for which the single-centre-of-inertia approximation is not valid and where it is hard to distinguish small load disturbances from noise and natural attenuation of the perturbation [83]. Also potential power quality issues due to the inserted microdisturbances should be investigated [83]. National Grid ESO is currently testing the approach introduced in Ref. [62] in their system [82]. Test results have not been published, neither has been the exact inertia estimation method. Moreover, it is hard to assess the performance of the suggested approach in low-inertia conditions in the ongoing testing, as very low-inertia conditions are sill rare events in today's system and the lack of published theoretical details hamper simulation studies.

4.3. Estimation of expected inertia: forecasting

Due to the instantaneous nature of the inertial response, the system operator does not have time to take actions in real time to deal with insufficient levels of inertial response available in the system. Therefore, the system operator should have an accurate estimate of the inertia that is expected to be available in the future to contract sufficient fast frequency reserves, adequately modify the system's inertia level or reduce the potential largest loss in the system operator's decision-making process explained in Section 2.3. Forecasts for different forecasting horizons can be used complementary to the frequency response requirement tables generated for different levels of demand, inertia and largest loss to

[11] The method can be applied during small disturbances, but the paper indicates that estimates from very small events generally have larger errors. The paper classifies disturbances in the Great Britain system as small if they cause a ROCOF as small as 0.03 Hz/s, which can be initiated by trips of around 200–400 MW. This type of events has been identified once every 4 days on average for the data set used in the study [3].

[12] The latter approach has been commercialized by Reactive Technologies [62].

identify when the system will potentially be at risk and inform the operational decisions to contract fast frequency response, reduce the largest loss of consumption or infeed, or take actions to increase the inertia. The required temporal resolution of the inertia forecasts depends upon the operational intervals defined by the temporal resolution of the ancillary service markets (e.g., hourly markets for fast frequency reserve in Nordic area [84]) and the temporal constraints of operational practices for generation redispatch (e.g., contractual arrangements for generators to be online are made per 30 min in the Great Britain system). However, the forecast per operational interval should represent an estimate of the lowest inertia level in the system for the given operational interval to assess the maximal ROCOF and frequency deviation within an operational interval and to limit the operational risk. For this reason, a higher temporal resolution of forecast is required, especially if the variability in the system within an operational interval increases with an increased penetration of renewable energy sources.

The literature on models to forecast system inertia focusses on point forecast models. Initial research efforts on physical models relate the system inertia to the online status of synchronous generators. This first approach to forecast system inertia only considers the contribution from transmission-system-connected synchronous generators and has been reported by the independent system operator ERCOT [67] and the Nordic TSOs [25]:

$$\widehat{E}^{I}_{t+k|t} = \sum_{i} \widehat{K}_{t+k|t,i} \cdot H_i \cdot P_i^{G,C} \tag{7}$$

where $\widehat{K}_{t+k|t,i}$ is the expected status of the synchronous generator unit i at time t for time $t+k$, H_i its inertia constant [s] and $P_i^{G,C}$ its generating capacity [MW]. However, the expected status of the generators $\widehat{K}_{t+k|t,i}$ is not generally available to all transmission system operators ahead of real time, e.g., in day ahead. Time-series models, such as the one presented in Ref. [85], prevent the dependence on forecasts of the generator statuses and only depend on historical estimates of the inertia in the system. The model presented in Ref. [85] is developed using estimates of the kinetic energy, i.e., the inertial response of rotating masses, in the Nordic system, as published on the Fingrid website [86], and estimated using the approach presented in Ref. [37]. The accuracy of these time-series models strongly depends on the accuracy and resolution of the ground truth inertia estimates used to train the forecast model. Moreover, physical and also the current time-series forecast models only consider transmission-system-connected synchronous generators' contribution, which results in an underestimation of the total system inertia as the contribution from demand has not been considered.

The Great Britain system operator additionally estimates the future inertia contribution from embedded units and demand using a explanatory regression model that links this inertia contribution to the load forecast.[13] This model thus relies upon forecasts of exogenous variables, such as load forecasts, on top of forecasts of generator statuses to produce forecasts of inertia:

$$\widehat{E}^{I}_{t+k|t} = \sum_{i} \widehat{K}_{t+k|t,i} \cdot H_i \cdot P_i^{G,C} + a \cdot \widehat{P}^{D}_{t+k|t} \tag{8}$$

where $\widehat{P}^{D}_{t+k|t}$ is the forecast of the system demand at time t for time $t+k$ [MW]. While originally a fixed regression constant a has been used for the system as a whole, linear regression analysis on regional inertia estimates has been applied to derive spatially differentiated empirical constants [3].

Currently available point forecast models for inertia, relying upon the reported status of synchronous generator units, are expected to decrease in accuracy for two reasons. First of all, due to the increased penetration of variable and uncertain renewable energy sources with zero marginal cost, the market dynamics are expected to increase and the day-ahead reported statuses are expected to be less accurate and more uncertain, which hampers the forecasting of the available inertia. This effect has been shown in the ERCOT system, where inertia forecasts based on generator reports ahead of real time typically overestimate the real-time inertia during periods with low energy prices [67]. Second, the share of units providing virtual inertia will increase. If these units are embedded in distribution systems, they are not directly monitored by the transmission system operator which challenges the forecasting of their inertia contribution. Moreover, units providing virtual inertia, such as wind generators, are typically more variable and uncertain in nature than synchronous generator units.

Two measures can be taken to deal with these challenges. First of all, an improved point forecast model of the status of the synchronous generators may reduce the point forecast error. A first approach is to model the energy trading to estimate the generators' statuses. However, modelling energy trading is not straightforward, especially for quantitative results [89]. Moreover, transmission system operators in power systems with independent market operators do not have access to the bids and offers in the energy markets and are only informed by the outcome of the market at gate-closure time close to real time, e.g., 1 h ahead of real time in Great Britain [26]. Therefore, it might be more beneficial from a system operator's perspective to identify relationships between the generators' online capacity and other system variables impacting the energy trading that are directly available to the system operator, such as historical data of the status of the different generators, historical data and forecasts of total transmission system demand, forecasts of wind and solar generation, interconnector flows, electricity prices, etc. Second, while current practice focuses on point forecasts, modelling the uncertainty on the forecasts enables the system operator to assess the risk of ROCOF and underfrequency relay tripping. Probabilistic forecast models are useful in this respect, as they represent the conditional distribution of the future inertial energy for different forecast horizons conditional upon the system state, for a variety of system states. The system state is characterized by a set of exogenous variables, such as demand, wind production, day-ahead electricity price and forecasts of the respective system variables. The linear regression model in state-of-the-art approaches provides a framework to estimate a predictive distribution of the inertia forecasts, but this is based on a set of strict assumptions, i.e., (i) the errors are statistically independent, (ii) the errors have a constant variance and (iii) follow a normal distribution. Alternative parametric, semi-parametric and non-parametric probabilistic forecast models should be developed for inertia forecasting.[14]

Traditional explanatory inertia forecasting models as the one introduced in Eq. (8) rely upon the assumptions that a linear, additive and stationary relation holds between system inertia and the exogenous variables, i.e., total system demand and the inertia contribution from synchronous generators. To avoid the assumption of linearity and additivity, the feasibility of non-linear, artificial neural network (ANN) models as explanatory models for inertia forecasting has been tested in Ref. [69]. The presented ANN models use total system demand, total generation from power-electronic interfaced generation and total generation from synchronous generators as input features to model the system inertia. General statements about the accuracy of the method cannot be made as the report only mentions the application of the approach in a simplified simulation context, which does not capture the actual stochastic behaviour of the inertia in the system [69].

The development of accurate inertia forecast models is hampered by the accuracy of state-of-the-art inertia estimation methods. First of all,

[13] Abundant literature is available on load forecasting in power systems. An overview can be found in Refs. [87,88].

[14] Probabilistic forecasting models have already been applied extensively in other energy forecasting contexts, such as load forecast, price forecasting and wind forecasting [87,90,91].

time-series models and explanatory models depend on historical ground thruth data of inertia. Second, the development of explanatory forecast models requires a large data set to ensure their generalization, especially if more flexible but also more complex machine learning model structures are used. State-of-the-art inertia estimation methods have only provided accurate estimates during discrete events so far, resulting in a data set too small for accurate forecast modelling. Near-continuous estimates have been inaccurate or their accuracy has not yet been proven. Moreover, the importance of accurate inertia estimates with high temporal resolution will become even more pronounced in power systems with large amounts of renewable energy sources, as the increasing variability in generator output that comes with renewable energy sources may ask for forecasts of inertia with higher temporal resolution in the future.

5. Classification of inertia estimation methods according to their scope

Inertia estimation methods may also be categorized based on their spatial resolution. Some methods are able to estimate the total system inertia or regional inertia, which makes them different in terms of their geographical scope. Other methods focus on the estimation of different contributors to the inertia, such as synchronous generators, demand or virtual inertia resources.

5.1. Geographical scope

Historical approaches to estimate the system inertia focussed on calculating a single value for the total system inertia based on the concept of centre of inertia, which is determined by the average system frequency [40–42,44]. This value of system inertia captures the contribution from generation, demand and virtual inertia resources, when present. Assuming a single value for inertia in the system is acceptable in strong transmission systems with limited variations of the frequency between locations. Lower inertia levels will, however, increase the risk for angle swings and oscillations between areas [79].

To improve the inertia estimates, recent efforts have been focussing on providing zonal estimates of the inertia or spatial inertia profiles. Zonal inertia estimates are more flexible than system inertia estimates, as aggregating the zonal inertia contributions gives the total system inertia, while the zonal or individual contributions cannot be derived from the system estimate. These zonal inertia estimates may be used by the system operator in procuring very fast frequency response services and in enhanced and coordinated frequency control methods [21]. Different approaches to divide the system in zones have been used in the literature: (i) division around the constraint boundaries of the network under analysis [16] or (ii) in zones in which angles and frequency are closely coupled [3,45,53]. The latter is preferable from a physical perspective.

5.2. Contributors to the system inertia

From a system operator perspective, it might be useful to get insight in the different contributors to the aggregated system inertia in a zone or in the total system. When total inertia levels are decreasing, the contribution of unmonitored contributors to the system inertia, such as demand and embedded units, will become more important and accurate estimates of these contributions are required. Forecasts of the inertia contribution of embedded units and demand may be used in advanced unit commitment models that simultaneously schedule energy and frequency response services [92].

Directly estimating the inertia contribution from demand and embedded units is challenging, which is also reflected in the limited research efforts in Table 1. Initially, rough estimates (e.g., still in use in Finland to estimate the inertial response of approximately 500 MW of production [37]) or fixed values for the contribution of embedded units and load to the system inertia were used (e.g., 20% for the contribution of load to the total inertia in Great Britain [16]),[15] or their contribution was just omitted [93]. Alternatively, the inertia contribution from embedded units and load can be estimated by subtracting the contribution from synchronous generator units from the total system inertia estimate during large disturbance events [46,49]. Estimating the contribution from synchronous generator units requires information about their online capacity[16] and their individual inertia constants. Originally, synchronous generators' inertia constants were estimated using the load ramp test, the probing test and the transient test [94–97]. Alternatively, dynamic online estimation based on PMU measurements has been proposed to estimate the inertia constants of synchronous generator units or virtual inertia resources, as indicated in the third and fourth column of Table 1. In these methods, inertia is estimated as a parameter in a dynamic frequency responsive model, matching the power output of the model with the power output from the measurements during the disturbance event. The comparison to derive the inertia constants can be done manually [47] or using a grey-box identification method that optimizes the parameters of a dynamic model of the frequency response of a generator unit by minimizing a weighted-mean-squared error between the power output from the dynamic model for the given frequency measurements related to the disturbance with the measured power output of the generator unit [46].[17] Alternatively, a two stage validation and calibration process has been suggested to validate the dynamic model accuracy of a generator based on PMU measurements and update the model parameters using an extended Kalman filter in case of model deficiencies [57]. One of the dynamic model parameters to be estimated in this approach is the inertia constant of the generator.

Based on the limited data set of estimates of the inertia contribution from embedded units and demand during large disturbance events, research efforts have developed explanatory models that relate the inertia contribution from demand and embedded units to the total system demand [46,49]:

$$E_t^{I,emb} = a \cdot P_t^D \tag{9}$$

where P_t^D is the system demand at time instant t. These models have predictive capabilities. However, due to the limited size of the data set, only simple model structures with a limited number of parameters to be trained, such as linear regression models, have been used to avoid overfitting [49]. This approach is currently used by National Grid ESO to estimate the inertia contribution of embedded units and demand [3]. The temporal resolution of the estimates of the inertia contribution of demand and embedded units, and therefore the size of the available data set, can be increased by using an estimation method with higher temporal resolution to estimate the total system or zonal inertia.[18]

6. Conclusion and the future of inertia estimation methods

Secure and cost-effective operation of low-inertia power systems requires accurate and reliable estimates and forecasts of inertia in the system on a close-to-continuous and regional basis, considering

[15] Ashton et al. indicated in 2015 that the contribution of demand and embedded units, such as distribution connected synchronous generator units, to total system inertia varies between 8% and 25%, with an average of 18.18% [16].

[16] If information about the generators' online capacity is not available, Bian et al. have proposed a method to estimate the generator contribution based on the produced power by fuel type [49].

[17] Different simulation models should be built for different types of generator units.

[18] An overview of different methods for total system or zonal inertia estimates with different temporal resolution with their characteristics and shortcomings has been given in Section 4.

contributions from generation, demand and virtual inertia resources. The state of the art in inertia estimation methods has evolved from delivering post-mortem, total system inertia estimates after discrete large power imbalance events towards close-to-continuous real-time inertia estimates with the possibility to make regional estimates. Regional estimates are crucial in low-inertia power systems consisting of strong regions interconnected by long links to deal with the geographical variations in inertia and frequency response, while near-continuous inertia estimates monitor the system's frequency response profiles with a high temporal resolution, which is crucial to deal with the operational challenges of variability of inertia over time induced in power systems with large amounts of variable renewable energy sources. Although important steps have been taken towards near-continuous inertia estimates, the accuracy and reliability of (near-)continuous inertia estimation techniques have not been adequately proven yet due to limited ground truth knowledge about the inertia in the system. Recommended directions for further work and future research are (i) the testing and validation of near-continuous inertia estimation methods to ensure that the techniques do not impact the stability of the system and to obtain more accurate estimates, (ii) getting more insight in the contributors to the system inertia in different operating states, especially the contribution of embedded units that are not observable and uncontrollable for the system operator, and (iii) the development of models to forecast future levels of total system inertia, zonal inertia or the inertia contribution from individual resources, such as demand and unmonitored embedded units.

The large amount of renewable energy sources in future power systems, leading to low inertia levels, challenge the inertia estimation. First of all, the calculation of the swing equation, the foundational equation of post-mortem and real-time inertia estimation methods, becomes more challenging. Fast frequency response will hamper the calculation of the ROCOF and power imbalance. Moreover, the system will have increased dynamic behaviour. Second, besides an increase in temporal resolution, an increase in spatial resolution of inertia estimates is required, as variations in inertia between different regions in low-inertia systems ask for a coordinated, well-localized frequency response. Third, new approaches to deal with units providing virtual inertia embedded in distribution systems are needed. These embedded units are out of sight of system operators and their inertia contribution is very hard to estimate with the state-of-the-art methods. For this reason, the current estimation practice, ignoring the inertia contribution of embedded units and the load, will underestimate the total inertia even more in power systems with low amounts of transmission-system connected synchronous generation and virtual inertia providers embedded in distribution systems. Approaches to specifically estimate the inertia contribution of demand and embedded units rely upon accurate estimates of the total inertia from which the inertia contribution of monitored, transmission-system-connected generators is subtracted. Due to the limited availability of reliable and accurate total system inertia estimates with high temporal resolution, estimation of the contribution of demand and embedded units currently relies upon inertia estimates during rare large disturbance events. Although methods to continuously estimate the total system inertia are currently being tested in the power system of Great Britain, their accuracy and performance are still to be published. Moreover, further work is needed to verify the impact of the small power injections in microdisturbance methods on the stability, security and power quality of the power system. Special attention should be given to the performance and the impact on stability and security during low-inertia conditions to make the technology future proof.

To ensure the secure and cost-effective operation of future low-inertia systems with more variability in available inertia, accurate forecasts of the inertia available in the system are crucial to inform system operators' decision making. The field of inertia forecasting has ample opportunities for progression. First of all, accurate inertia forecasting with a sufficiently high temporal resolution for low-inertia systems is hampered by the limited quality and amount of ground truth inertia data generated by state-of-the-art inertia estimation methods. Moreover, the state of the art on inertia forecasting models is limited to explanatory, linear regression models with a limited number of exogenous variables and time series models, and focuses on providing point forecasts. However, the system operator would benefit from probabilistic inertia forecasting models to assess the risk of ROCOF and underfrequency relay tripping and to inform decision making. Once a large set of reliable and accurate inertia estimates of the total system or a zone as well as of the different contributors are available with a high temporal resolution, these data can be used to develop probabilistic forecasting models. The resulting probabilistic forecasts of inertia may inform system operator's decisions on the modification of the potential largest loss or the inertia in the system, on frequency response procurement or on the volume of inertia to buy on a market for inertia. Alternatively, one can look into the benefits of direct forecasts of predictive distributions of system variables, such as rate of change of frequency and frequency deviation, rather than the system parameter of inertia to estimate the probability of potential issues in the frequency response. Similar approaches of integrated forecasting have been suggested in the context of determining market bids of power plants with uncertain production [98].

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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