Measurement-Based Estimation of Inertia in AC Microgrids

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***Abstract*—This paper presents an improved method to estimate the available inertia in an islanded AC microgrid. Inertia estimation is carried out based on measured frequency response for any arbitrary disturbance that occurs in the system. Modifications are made to the conventional swing equation-based curve-fitting method to obtain an accurate estimate for a system with high penetration of renewable generations. A polynomial curve fit over the total power generation is introduced to estimate the size of the disturbance accurately. Additionally, a variable order polynomial fit is carried out over the measured frequency, which not only improves the estimate of inertia but also helps to refrain the influence of network topology and size/location of the disturbance. The test microgrid system considered is a modified Standard IEEE distribution network, which consists of radial feeders and distributed generations. Firstly, the proposed method is tested on a system with only synchronous generations to assess the accuracy of the estimate. This is followed by the integration of Type 3 and Type 4 wind turbines, and a PV array within the microgrid system. Virtual inertia control is then implemented in the wind turbines to obtain inertial support. Estimation study of the microgrid system with virtual inertia is then carried out. The developed estimation method can accurately estimate the inertia provided by the synchronous sources within the generation mix. Finally, from all the results and observations, the inertia estimation process in a microgrid system is segregated into synchronous and nonsynchronous inertia estimation.**

***Index Terms*—Frequency stability, inertia estimation, microgrid, renewable sources, swing equation, virtual inertia.**

I. Introduction

WITH the increasing concerns of global warming and climate change, many countries have set ambitious goals to increase their share of energy production from renewable sources in the coming decade [1]–[3]. One of the key hurdles in deploying a high penetration of renewable generation is the reduction in system inertia [4], [5]. The total mechanical inertia of synchronous machines in a power system opposes any frequency disturbance, keeping the system relatively stable for any credible contingencies. However, most renewable sources are connected to the power network through a power electronic converter interface and provide minimal to no inertial support. Hence, with an increasing share of renewable generation, the overall inertia of the system reduces, leaving the system more vulnerable to frequency stability issues [5]–[8]. Reduction in inertia results in a rapid Rate of Change of Frequency (RoCoF) and a larger frequency deviation (nadir). Such conditions can trigger a combination of RoCoF relays and Under Frequency Load Shedding (UFLS) relays, and can even cause a cascading trip of generators resulting in a complete system outage.

The concept of microgrid [9]–[11] has gained popular attention in recent years as a viable solution to large integration of distributed renewable resources at medium or low voltage networks. Microgrids are a collection of loads and sources, which can be controlled as a single entity, with capabilities of operating in a standalone or grid-connected mode. Some other distinct advantages of microgrids include supply power to remote areas and segregation of large systems into multiple smaller units to prevent complete system outages. Even though the concept is attractive, the increased share of renewable generation and smaller system size further aggravates the issue of diminishing inertia and frequency stability.

To overcome the challenges in the reduction of inertia, an accurate estimate of the available inertia in the system is crucial. With an accurate estimate, system operators can take corrective actions to overcome the challenges of frequency stability. These actions can include implementation of appropriate virtual inertia controls and deployment of a suitable frequency containment reserves depending on the level of system inertia [7], [12]. The conventional swing equation-based method of inertia estimation that calculates the value of inertia constant by observing the frequency response for a known disturbance is widely used for power system studies [8], [13]–[20]. However, the accuracy of the estimate in this conventional method is a major concern. Moreover, in the case of real-time/online inertia estimation tools [6], [8], the accuracy becomes more unpredictable.

Various factors can influence the accuracy of the estimate in inertia [14]. One of the factors is the accuracy in estimating the size of the disturbance. Most of the earlier studies on inertia estimation assume a known size of disturbance [13], [17], [21]. This means that the change in active power, before and after

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the instant of disturbance, is known. However, the information on the size of the disturbance may not be readily available. Moreover, the change in power at the point of disturbance and the overall change of power that is seen by the generators are different. At the instant of disturbance, network voltages tend to fluctuate, and with a significant contribution of constant impedance loads, the total power consumed also fluctuates. This has a significant impact on the accuracy of the estimated value of inertia. Refs. [22], [23] have modeled the change in power by including the effect of voltage variations at all the buses. Since measurements of voltages at all the load buses are not always available, the method is less ideal in practice.

Another factor that affects the accuracy of the inertia estimate is the method used for the calculation of RoCoF. Most of the earlier studies that rely on the polynomial curve fitting process of the measured frequency response are limited by the use of a fixed order of polynomial for the curve fit [8], [13], [15]. For example, in [13], the authors have determined that a fifth-order polynomial is suitable for the estimation of inertia in Japan's power system. This places further limitations on the size/topology of the system, location, and size of the disturbance.

Currently, a significant amount of literature is available on the estimation of inertia at a power system level where conventional synchronous machines dominate [8], [13]–[20]. However, only a limited amount of work that examines the estimation of inertia in isolated renewable generations and systems with high renewable penetration is available [6], [24]. In the case of smaller and more vulnerable systems such as microgrids, very limited studies are available on inertia estimation. Hence, in this paper, estimation of inertia in a microgrid system by observing frequency response during any arbitrary disturbance is proposed. The proposed estimation method makes various enhancements to the conventional method to improve the overall accuracy of the estimate. Curve fitting on the total power generated is introduced to estimate the size of the disturbance correctly. Moreover, a variable order polynomial fit of the frequency response is implemented, which further improves the accuracy and versatility of the proposed method.

The developed estimation method is first tested on a test microgrid system with only synchronously connected Diesel Generations (DG). Further, the system is integrated with various renewable sources such as Type 3 (Doubly Fed Induction Generator - DFIG) and Type 4 (full converter) wind turbine generators (WTG), and a PV array. Finally, virtual inertia control is also implemented in the Type 3 WTG, and estimation studies are carried out. The proposed estimation method accurately estimates the inertia that is provided only by the synchronous machines within the generation mix. The results obtained, thus, paves a way to segregate the inertia estimation process into synchronous and nonsynchronous inertia estimation. The correct estimation of synchronous inertia in microgrids will help system operators to determine a minimum level of synchronous inertia and to operate the system within safe RoCoF limits. Moreover, the estimate can help operators to design inertia control services that will cater to specific microgrid networks.

This paper is structured as follows. Section II presents a brief discussion on the conventional method of estimating inertia in a power system. The following section details the improved estimation method that is developed for a microgrid system. Section IV presents the results of the estimation study carried out on the test microgrid system. Discussion of the observed results is provided in Section V. The conclusions are presented in Section VI.

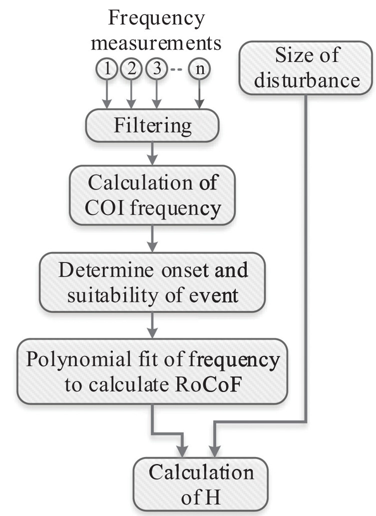

Fig. 1. Estimation of inertia in power system.

II. Conventional Estimation Method

One of the widely accepted methods of estimating inertia in a power system is based on the swing equation that describes the electromechanical behavior of a multi-machine system [6], [8], [13], [15]–[17]. The swing equation is given as

$$\frac{2H_{\mathrm{sys}}S}{f_0}\frac{df}{dt} = P_{\mathrm{m}} - P_{\mathrm{e}}, \tag{1}$$

where f_0 is the nominal system frequency, P_{m} and P_{e} are the total mechanical and electrical power of the synchronous generators, respectively, S is the nominal apparent power of the system, f is the measured frequency, and $\frac{df}{dt}$ is the time rate of change of frequency (RoCoF) (Hz/s). For a system of N synchronous generating units, the net system inertia, $H_{\mathrm{sys}}\ (s)$ is defined as

$$H_{\mathrm{sys}} = \frac{\sum_{i=1}^{N} S_i H_i}{\sum_{i=1}^{N} S_i} = \frac{\sum_{i=1}^{N} S_i H_i}{VA\ \mathrm{base}}, \tag{2}$$

where S_i and H_i are the rated apparent power and inertia constant of the i^{th} generator, respectively. Values of H_{sys} and H_i can also be expressed in terms of a nominal system VA base. From (1), it can be observed that any imbalance between the total generation and load will result in a non-zero value of RoCoF. Hence, with a correct measurement/calculation of RoCoF for a known disturbance in the system, the equivalent inertia constant of the system can be estimated.

The conventional approach of estimating inertia by observing the measured frequency response is described in Fig. 1. For a known size of disturbance, such as tripping of generation, load

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rejection, outage or energizing of a feeder or a DC link connection, the behavior of the frequency measured through frequency disturbance recorders/phasor measurement units (PMU) are observed. In a large power system, dynamic frequencies measured at different locations varies to a certain extent, which is caused mainly due to swings between groups of generators. Hence, the concept of Center of Inertia (COI) frequency becomes essential to get a correct estimation of inertia. The COI frequency of the overall system is then calculated from the filtered individual frequency measurements (f_i) by using the following equation [8]

$$f_{\mathrm{COI}} = \frac{\sum_{i=1}^{N} f_i H_i}{\sum_{i=1}^{N} H_i}, \tag{3}$$

where H_i of each generator is expressed at a common VA base.

The next step in the estimation process is the identification of the onset of the grid disturbance, which is carried out by examining the value of RoCoF and deciding on a threshold value for detection (for example, 0.04 Hz/s in [15]). This step is followed by a polynomial fit of the frequency curve starting from the identified point of disturbance. A predefined order of polynomial is used for the curve fit, which is performed for a duration that would capture the inertial response from the generators. For a known size of disturbance, the value of the inertia constant is determined by using the following equation that is obtained by rearranging (1):

$$H_{\mathrm{sys}} = \frac{1}{2S}\frac{f_0 \Delta p}{\frac{df_{\mathrm{COI}}}{dt}} = \frac{1}{2S}\frac{\Delta p}{\frac{d\left(\frac{\Delta f}{f_0}\right)}{dt}}, \tag{4}$$

where Δf represents the deviation of the measured COI frequency from the nominal frequency f_0, and Δp is the size of the disturbance. The value of $\frac{d(\frac{\Delta f}{f_0})}{dt}$ is determined by fitting a polynomial curve on the frequency response, $\frac{\Delta f}{f_0}$, as given in the following equation

$$\frac{\Delta f}{f_0} = A_n t^n + A_{n-1} t^{n-1} + \cdots + A_1 t. \tag{5}$$

The result of the curve fit determines all the coefficients of the fitted polynomial ($A_1, A_2, \ldots, A_n$). Thus, the time derivative of (5) at the instant of the disturbance (i.e., starting of the curve fit at $t = 0$ s) gives the denominator term in (4) as A_1. Hence, the required value of inertia constant is estimated as

$$H_{\mathrm{est}} = \frac{\Delta p}{2SA_1}. \tag{6}$$

III. Estimation of Inertia in Microgrids

Most of the reported studies on inertia estimation are predominantly focused on large conventional power systems, where the inertia constants of the synchronous generators are known, or the frequency transients can be analyzed directly using the swing equation. This paper, on the other hand, investigates the problem of estimating inertia in a much smaller microgrid system where renewable generations are predominant, and frequency fluctuations are relatively more severe. Moreover, virtual inertia response from renewable generations will also play a vital role in maintaining the frequency stability in such systems. The following subsections detail the microgrid test system used for the study and the proposed inertia estimation method to overcome various challenges for estimating inertia in a microgrid system.

TABLE I
Ratings of Renewable Generations

Renewable Sources	Capacity (each unit)	Inertia Constant - H (Source VA base)
Type-3 WTG	1.5 MW	5 s - blades & generator combined
Type-4 WTG	2.0 MW	4.32 s - blades and 0.62 s - generator
PV array	250 kW	NA

A. Schematic of the Microgrid Test System

Fig. 2 shows the single line diagram of the microgrid system, which is a modified IEEE standard distribution system [25]–[28], that is used for this study. The test system is a 13.8 kV distribution network that consists of three radial feeders connected to a larger network of 69 kV. The overall system load is 8.3 MW and 3.97 MVAR, which are supplied by diesel generators (DG1 - DG3) and renewable sources. The net inertia constant of the system from all the DGs is $H_{\mathrm{sys}} = 8.315$ s at a base of 5 MVA.

In terms of generation from wind, Type 3 and Type 4 wind turbines are chosen because of their popularity and capability to implement virtual inertia controls [24], [29]. PV arrays operating at their Maximum Power Point (MPP) without any energy storage reserves are also considered. The ratings of the renewable energy generations are provided in Table I. Multiple units of each of these sources are connected to the 13.8 kV substation to vary the penetration level of renewable generation. The current model of the microgrid network is considered due to its popularity in the literature for frequency stability studies in Microgrids [25]–[28]. Moreover, the reasonably large load (8-10 MW) and medium voltage levels (69 & 13.8 kV) make it easier to integrate WTGs with their actual size and ratings.

Simulation studies of the microgrid system are carried out in MATLAB/Simulink environment. Since the time scale of interest lies around the electromechanical scale, which can range from a couple of milliseconds to several seconds [5], [30], both phasor and average models are used for the simulation studies.

B. Proposed Inertia Estimation Method

In this subsection, an improved method to estimate inertia in a microgrid system is presented. The proposed estimation method is based on two significant enhancements in the conventional method that not only improve the accuracy of the estimate but also reduce the influence of the size/location of the disturbance and the topology/size of the system. Firstly, an additional curve-fitting process over the total power generated is carried out to obtain the accurate size of the disturbance. Secondly, significant improvements are made in the conventional curve-fitting process of the measured frequency by introducing an algorithm to implement a variable order polynomial fit.

1) Polynomial Fit of Power - Δp Calculation: One of the significant challenges in estimating the accurate value of inertia

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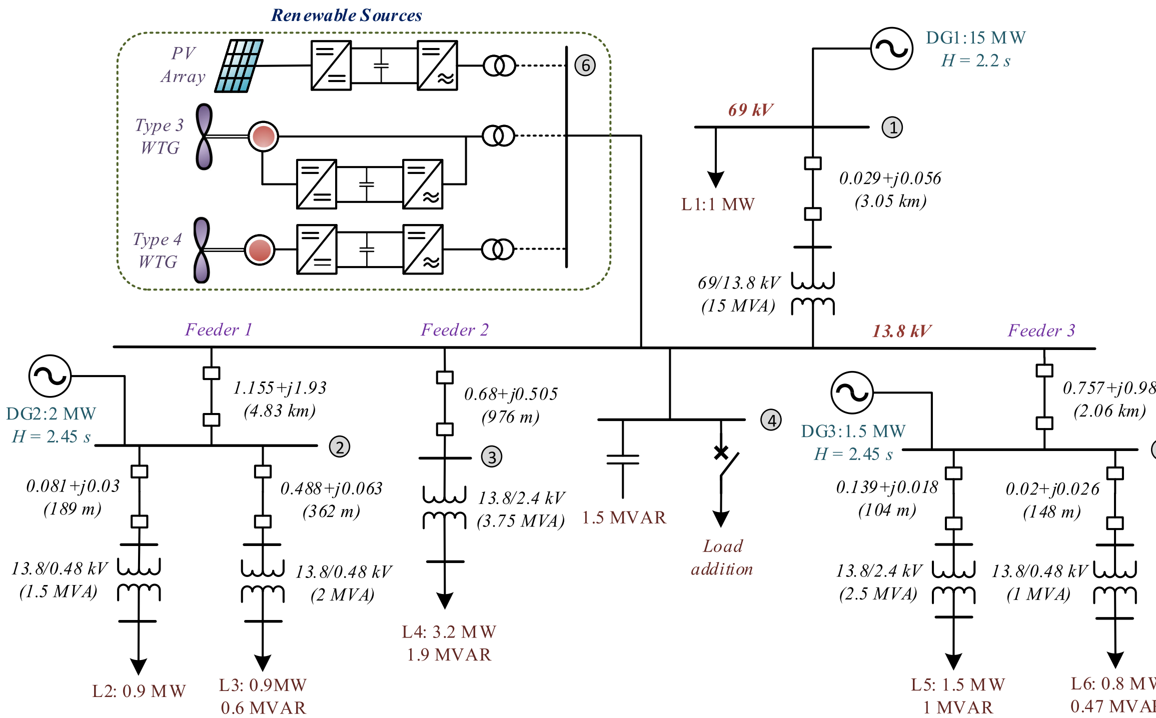

Fig. 2. Schematic of the test Microgrid system.

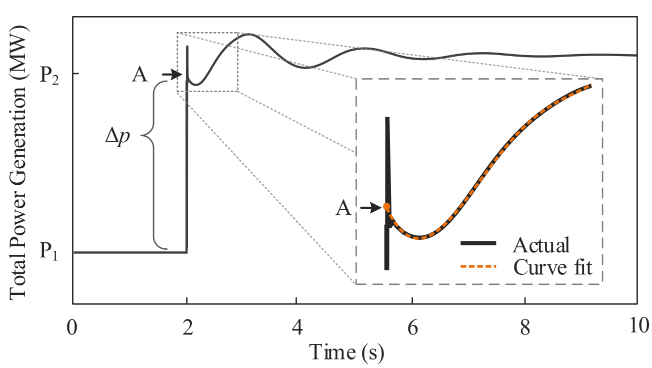

Fig. 3. Polynomial fit of power to calculate Δp for a step change in the load.

is determining the exact value of the size of the disturbance as seen by the generators. In this study, a curve fitting of the total power generation at the instant of disturbance is introduced to pinpoint the actual change in power during any arbitrary disturbance within the microgrid system. The proposed curve fitting process becomes a necessity as measurements on the exact size and location of the disturbance may not be readily available. Moreover, the variation of overall power generated/consumed during the disturbance is very high due to various network conditions (as can be observed from Fig. 3), rendering the use of the measured size of the disturbance directly for inertia calculation inaccurate. Measurement noise and resolution are other concerns that adds to the limitation.

For this study, active power measurements at the terminals of all generators are assumed to be available. A fifth-order polynomial is chosen for the curve fit after an analysis of various disturbance sizes simulated at different locations in the microgrid. Fig. 3 shows a generic example of the active power response from the generators in the microgrid for a step change in load. The polynomial curve fitting process is applied for a duration of 1 s (from the onset of the disturbance) on the total active power generation. The duration of the curve fit is chosen such that it captures the relatively narrow time frame of inertial response in a microgrid system. From the result of the curve fit, the value of the total power that is generated just after the instant of the disturbance (point A) can be traced and accurately estimated. The net change in power, before and after the disturbance, in this case, is entirely supplied by the inertial response of the system. With this additional curve-fitting process, the total change in power (Δp in (6)) for any arbitrary disturbance can be calculated accurately. The results of the curve fitting are provided in Section IV.

2) Variable-Order Polynomial Fit of Frequency Response: The final and the most crucial step in the estimation process is curve fitting of the measured frequency response. Some factors need to be carefully determined before the final estimation is carried out. This includes

1) duration of the frequency curve fit and
2) order of the polynomial used for the curve fitting.

Within the duration of the curve fit, which normally lasts for up to a few seconds (from the start of the event up to maximum frequency deviation), the effect of the inertial response should also be captured. It is observed that for a larger duration (for example, 2.5 s from the point of disturbance), a larger order polynomial is required for an acceptable fit, while with a very short duration, much finer resolution and more accurate data points are needed. Hence, a careful trade-off between the two

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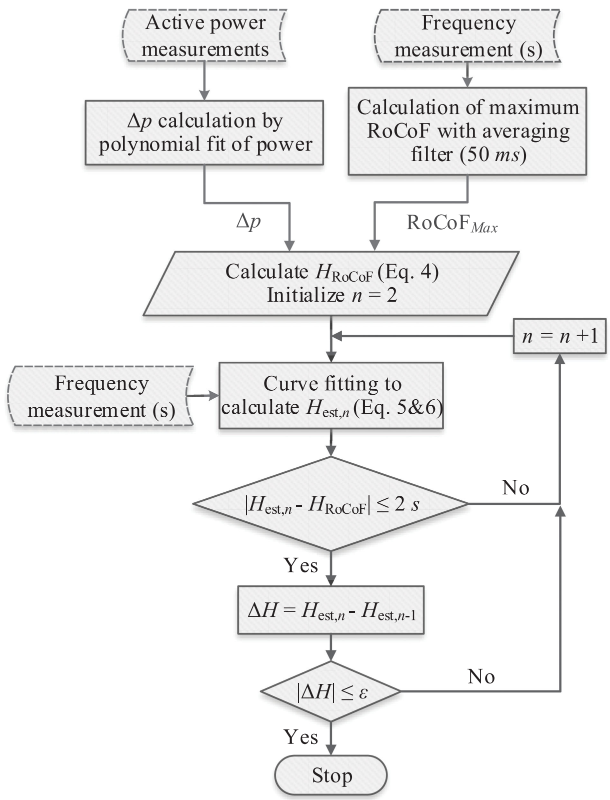

Fig. 4. Variable order polynomial fit of frequency.

options is required. In this study, with fast-acting governor of diesel generators being present, the optimal duration of the curve fitting is considered to be 0.5–1 s.

To overcome the limitations on the size of the system, and location and size of the disturbance, a variable-order polynomial fit in frequency is proposed. Fig. 4 shows the procedure of estimating the value of inertia constant with this method. As the value of Δp is determined from the curve fit (explained in Section III-B1), and the value of maximum RoCoF at the point of disturbance is also available from the measured frequency data, a rough estimate of inertia constant ($H_{\rm RoCoF}$) is calculated using (4). A moving average filter of 50 ms is applied to the measured RoCoF value to minimize the effect of measurement errors or noise. The next step is to initialize the starting order of the polynomial to $n = 2$. This is followed by a curve fitting with $n^{\rm th}$ order polynomial and calculation of the corresponding value of inertia constant ($H_{{\rm est},n}$). The calculated value is then compared with the value of $H_{\rm RoCoF}$ to ensure that the estimate is within a reasonable limit (± 2 s at 5 MW base, i.e., 24% of $H_{\rm sys}$). If the condition is satisfied, and if it is not the first iteration of the loop, the error of the estimate between the previous and current step (ΔH) is calculated. This is followed by a comparison of ΔH with a preset minimum tolerance value (ϵ). If the condition is satisfied, the current order of the polynomial is considered, and the value of $H_{{\rm est},n}$ is used as the final estimate. If not, the loop continues with an increment in the order of polynomial until convergence is met.

The order of the polynomial fit can be limited to a maximum value ($n_{\max}$) within the algorithm. If the search cannot find the right order within this limit, the value of ϵ can be increased until the loop converges. For this study, $n_{\max}$ is set at 25, and ϵ is set at 0.002 s, which is increased by a factor of 0.002 s until convergence is achieved. Fig. 4 also shows the required measurements of frequency and active power within the overall estimation process. For the study, measurements are carried out at a rate of 1 sample per cycle of the frequency (16.67 ms for the 60 Hz system).

With the proposed modifications made in the estimation algorithm, simulation studies are carried out in the microgrid system to assess its accuracy. The results of the estimates are provided in the following Section IV.

IV. Performance Evaluation

Simulation studies are carried out for various configurations of the microgrid to test the accuracy of the proposed inertia estimation method. Since the considered microgrid system is relatively small in size, frequency measurement from any part of the system can be considered as the COI frequency. However, in this particular study, since the speed measurements of all the synchronous machines are available, the COI frequency is calculated using (3). One of the essential steps to carry out curve fitting of the measured frequency response is to identify the time of onset of the disturbance. For this study, a RoCoF threshold of 0.05 Hz/s (with 50 ms moving average filtered value) is used to identify the exact starting time of the event.

Firstly, estimation study for a system with only synchronous DGs is carried out. This is followed by inertia estimation of the microgrid system with the integration of renewable sources operating at their nominal maximum power output. Finally, the developed estimation method is tested for a microgrid system with virtual inertia support from WTGs.

A. Estimation With Only Synchronous Generators

The microgrid system, for this study, consists of only diesel generators (DG1-DG3 as shown in Fig. 2). To estimate the value of the inertial constant, observations and analysis of the frequency response for various disturbances are carried out. The disturbance simulated is either a step change in load or a generator trip applied at various locations.

The pre-disturbance steady state net generation from all the DGs is 8.574 MW and 2.483 MVAR. For a step increase of 1 MW load ($\approx$12% of the total load), introduced at $t = 2\ s$ and connected at bus 4, Fig. 5 shows the frequency response. It can be observed that the frequency nadir is 59.88 Hz, and the maximum RoCoF at the instant of the disturbance is -0.629 Hz/s.

To find the actual change in power, Δp, net power generation just after the instant of disturbance needs to be calculated. From Fig. 6, it can be observed that the measured aggregate power (blue curve) fluctuates at the beginning of the disturbance, rendering the direct use of measured value inaccurate. Hence, by using curve fitting of power, as described in Section III-B1, the actual active power generation immediately after the disturbance is calculated as 9.439 MW. Thus, the total change in power

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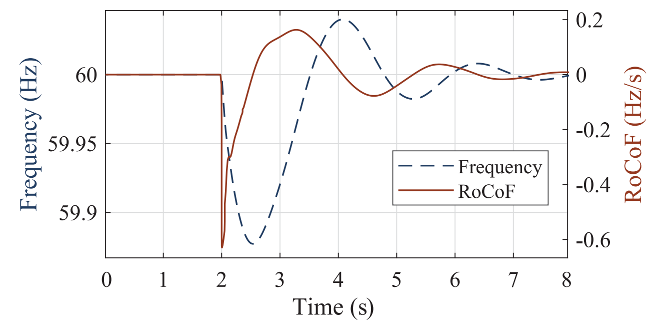

Fig. 5. Frequency and RoCoF plot for load change of 1MW at $t = 2$ s.

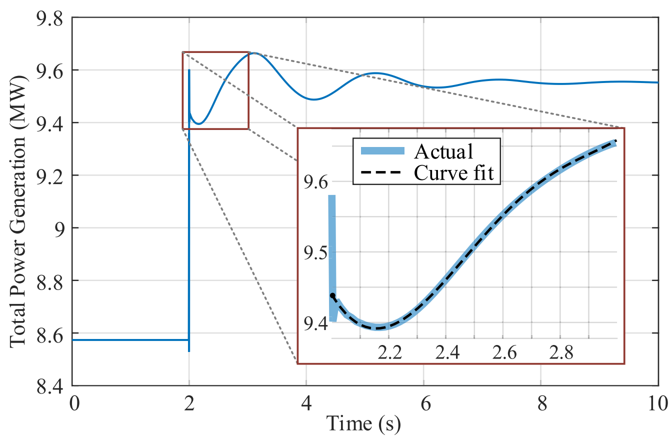

Fig. 6. Curve fitting of total power generated after the disturbance to calculate change in active power (Δp).

(seen at the generator terminals) during the disturbance is $\Delta p = 0.866$ MW. This deviation in the calculated value of Δp as compared to the actual 1 MW step change in the load at the rated voltage is primarily due to small deviations in the load bus voltages at the instant of disturbance. With the estimated value of Δp, and the measured value of maximum RoCoF, H_{RoCoF} in (4) is calculated as 8.254 s at a base of 5 MVA. Comparing with the actual analytical net inertia constant of all the DGs ($H_{\mathrm{sys}} = 8.315$ s), the error in the estimate is -0.8%. However, it is important to note that, in practice, maximum RoCoF based calculation of inertia is not used as the accuracy will generally deteriorate with level of noise in the measured frequency.

Fig. 7 shows the curve fitting of frequency response for a duration of 0.5 s using the proposed variable order polynomial fit described in Section III-B2. With the frequency response curve fit, the coefficient A_1 (in (5)) is calculated as 0.01054, and the corresponding value of H_{est} is 8.214 s. As compared to the actual net inertia of the DGs, the estimate has an error of -1.21%. The results for different step changes in load at bus 4 are summarized in Table II, and it can be observed that the proposed method of inertia estimation gives an accurate estimate. As compared to the conventional method, the improvement is not very significant for a system with only synchronous generations. For example, with the conventional method, error for the disturbance of 0.25 MW is calculated as 4.6%.

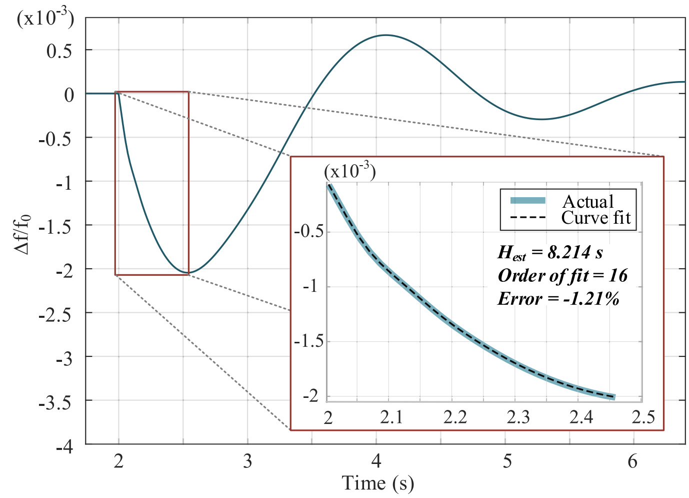

Fig. 7. Curve fitting of measured frequency response for estimation of inertia under a step load change of 1 MW at bus 4.

TABLE II
INERTIA ESTIMATES UNDER VARIOUS STEP LOAD CHANGE

Disturbance	Load %	Δp (MW)	Polynomial Order	H_{est} (s)	Error
0.25 MW	2.9%	0.218	20	8.235	-2.06%
0.5 MW	5.8%	0.434	19	8.313	-0.03%
1.0 MW	11.7%	0.866	16	8.214	-1.21%
2.0 MW	23.3%	1.675	17	8.515	2.41%

Similar studies have been conducted for other forms of disturbances to validate the proposed estimation method, which includes loss of generators, DG2 and DG3, and step load changes at bus 2. In all the studied cases, the average error in the estimate is found to be less than 2%.

Another aspect of the proposed estimation method, more precisely the variable order polynomial fit of frequency, is tested to evaluate the inertial contribution of residual synchronous sources. Such sources are generally smaller generations whose contribution to the total online inertia is not accounted for in the conventional inertia estimates. An additional DG of 1.5 MW and $H = 2.45$ s (at its base, and same ratings as DG3) is connected at the 13.8 kV substation to represent the residual sources. The additional DG increases the total inertia constant of the microgrid to 9.05 s at 5 MW base. Estimation study using the variable order polynomial fit in frequency is conducted for various disturbance size. It is to be noted that the polynomial fit of power to calculate Δp cannot be used for the test as the output power of all the DGs is not known. Instead, the value of Δp has to be estimated from known, and available measured quantities such as bus voltages [22], [23] and a limited number of generation output [31]. However, for validating the current study, accurate values of Δp are assumed to be available, and the average value of H_{est} is calculated as 9.013 s (with an error of -0.4%). Hence, with the developed method, even with a reasonable error in the estimation of Δp, the influence of residual sources can also be captured to a certain extent.

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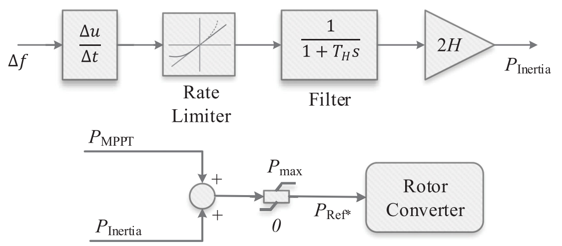

Fig. 8. Implementation of virtual inertia control in DFIG wind turbine.

B. Estimation With Renewable Generations—No Virtual Inertia Support

Type 3 WTGs with capacities of 1.5 MW to 4.5 MW, and Type 4 WTGs with capacities of 2 MW to 4 MW, all operating at their MPP are connected to the 13.8 kV substation (Bus 6) of the microgrid system. Simulation studies of the microgrid system with the WTGs are carried out at wind speeds of 11 m/s. The results of the estimation show that, without any virtual inertia control, the WTGs do not contribute to inertia support, as expected. It is to be noted that all the three synchronous DGs remain connected to the system. Similar to the results of the WTGs, the PV array (250 kW - 2 MW) operating at MPP do not contribute toward system inertia. Therefore, even after the integration of WTGs and PVs, operating at their nominal maximum power output, the results are similar to the base case.

C. Inertia Estimation With Virtual Inertia Support

In this paper, RoCoF based virtual inertia control has been implemented on Type 3 WTGs as shown in Fig. 8. An additional control loop is added to the MPP reference (P_{MPPT}) to generate the inertial reference power (P_{Inertia}), which yields the final active power reference of the WTG. The control is achieved by measuring the deviation of frequency from the nominal value (Δf) at the terminals of the wind turbine generator. The RoCoF signal calculated from Δf is passed through a low-pass filter and a constant gain $2H$ to obtain the required inertial power reference, P_{Inertia} [5], [32], [33]. The value of inertia constant (H) is the combined inertia of both the wind turbine blades and the generator. The time constant of the filter is chosen to be $T_H = 0.2\ s$.

Fig. 9 shows the frequency responses to a step load change of 2.5 MW at bus 4 under different WTG penetration levels. From the same figure, it can be observed that the maximum RoCoF and the frequency nadir improve with higher penetration of wind turbine. The reason is that the WTGs now contribute towards the overall system inertia. Moreover, the time to reach the minimum frequency also improves.

The general assumption is that the overall inertia of the system should improve if none of the synchronous generations are displaced, and virtual inertia is introduced in WTGs. However, the nature of inertial response from WTG is different from that of inherent inertial response from a synchronous machine. Therefore, the swing equation-based inertia estimation method will not be able to capture the emulated inertial response adequately.

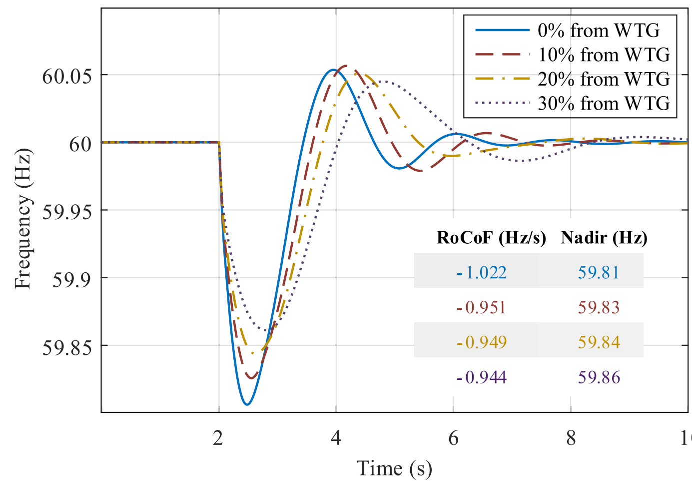

Fig. 9. Comparison of frequency response at different penetration levels of DFIG wind turbines with virtual inertia support for a disturbance of 2.5 MW.

TABLE III
INERTIA ESTIMATION WITH VIRTUAL INERTIA

WTG (MW)	Dist. (MW)	Δp_{cal} (MW)	RoCoF (Hz/s)	Nadir (Hz)	H_{est} (s)	Error$_1$ (%)	Error$_2$ (%)	Error$_3$ (%)
1.5 MW	0.5	0.446	−0.322	59.94	7.90	***−4.99***	7.07	20.02
	1.0	0.888	−0.639	59.88	8.21	***−1.31***	5.77	19.06
	1.5	1.313	−0.951	59.83	8.19	***−1.52***	6.48	21.64
	3.0	2.557	−1.856	59.66	8.11	***−2.44***	8.19	26.93
3.0 MW	0.5	0.443	−0.321	59.95	8.08	***−2.79***	14.8	29.58
	1.0	0.894	−0.640	59.89	8.18	***−1.56***	16.8	30.65
	1.5	1.318	−0.949	59.84	8.37	***0.65***	12.0	27.49
	3.0	2.526	−1.890	59.69	8.25	***−0.80***	11.1	31.95
4.5 MW	0.5	0.437	−0.317	59.95	8.36	***0.59***	34.1	53.43
	1.0	0.887	−0.640	59.91	8.31	***−0.08***	35.3	52.57
	1.5	1.319	−0.951	59.86	8.48	***2.00***	27.6	45.16
	3.0	2.514	−1.903	59.73	8.60	***3.41***	20.0	43.24

Error$_1$ Developed estimation method
Error$_2$ Conventional method with polynomial fit on power (Δp_{cal})
Error$_3$ Conventional method of estimation

Hence, the inertia estimate, using conventional swing equation-based approaches, in a renewable energy based microgrid with active virtual inertia response is likely to result in an inaccurate estimate.

The proposed estimation method is used again to estimate the inertia of the microgrid system. Table III shows the estimates of inertia for four sizes of disturbance and three WTG penetration levels. The errors in the estimates are calculated solely based on the known net inertia of the three DGs, which is 8.315 s at a base of 5 MVA. With additional inertial support from WTG, the total inertia of the new system is expected to be more than the net inertia of the DGs. However, it can be observed from Table III that the estimated value of inertia obtained by using the developed swing equation-based method (Error$_1$) accurately measures the inertia from synchronous machines only. The error in this estimate remains well below 5%. Without an accurate estimate of Δp, and with a constant 5^{th} order polynomial fit of frequency, the conventional method (Error$_3$) shows a substantial increase in the error of estimate. However, the increase in the

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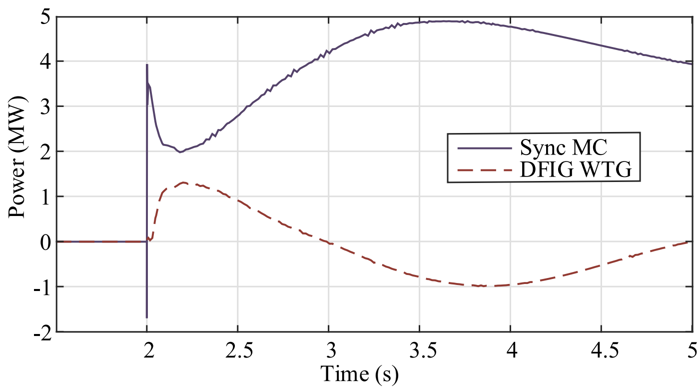

Fig. 10. Comparison of inertial response of synchronous generator (Inertial + governor) and that of DFIG WTG. 4.5 MW WTG penetration and 4MW disturbance.

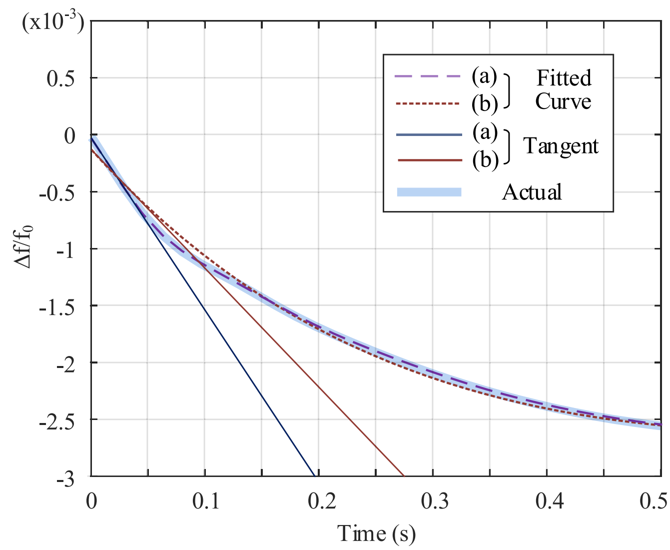

Fig. 11. Comparison of frequency curve fit for inertia estimation in (a) *Developed method*: polynomial order - 18, duration of fit - 1 s, $H_{\text{est}} = 8.37$ s and (b) *Conventional method*: polynomial order - 5, duration of fit - 2.5 s, $H_{\text{est}} = 11.85$ s.

estimate cannot be accounted for an accurate contribution from virtual inertia. This is because of the relatively large estimate as compared with the maximum possible contribution from the WTGs (compared with a synchronous machine of same inertia connected to the microgrid). Moreover, the variation of the estimate for the conventional method with different size of disturbance is also relatively high. Hence, using the developed estimation method, system inertia from synchronous machines can be accurately estimated even in the presence of WTGs despite their virtual inertia contribution.

The above results and discussion highlights the need to estimate inherent inertia from synchronous machines and virtual inertia from power electronic interfaced sources (renewable generators, storage) separately as the two inertial responses have different characteristics. In this backdrop, Section V discusses the segregation of inertia contribution and the estimation process in a microgrid system into synchronous and nonsynchronous inertia estimation.

V. Discussion: Estimation of Synchronous and Nonsynchronous Inertia

A comparison of inertial response provided by synchronous machines and DFIG WTG with virtual inertia control is shown in Fig. 10. It can be observed that inertial response from the DGs are instantaneous (step change in the power output), while the release of additional power from the WTG is slightly delayed. This is because synchronously connected machines inherently respond to the total power imbalance, that is, the difference of the total input mechanical power to the generators and the total electrical power demand. However, in the case of WTG, the output inertial power is based on the RoCoF measured at its terminals. As the drop in frequency is the outcome of kinetic energy being released from the synchronous machines due to decrease in their rotational speed, the delay in virtual inertia response of the WTG is expected. Besides, delay in virtual inertia can also be partly attributed to frequency/RoCoF measurement delay which is used as a feedback signal for virtual inertial response from the WTG.

Analyzing the profile of energy release from both types of sources, a classification on the type of inertial response and its estimation process can be made. Since the inertial response from WTG is relatively delayed at the instant of disturbance, its contribution is less effective during the first few cycles of operation after the disturbance. From the swing equation given in (1) and (4), it can be observed that, for a fixed value of Δp, the RoCoF at the instant of disturbance (maximum RoCoF) relates directly to the value of the inertia constant. Additionally, the coefficient of the polynomial, A_1, in (6) is also the slope of the curve at the start of the disturbance. Hence, with the developed estimation method, the synchronous inertia of the microgrid can be segregated and estimated accurately before virtual inertia response takes full effect.

Fig. 11 shows a comparison between the frequency curve fitting of the conventional and the developed method. The conventional method struggles to achieve an acceptable fit at the beginning of the disturbance, where the frequency response is not influenced by virtual inertia from the WTGs. This is evident from the difference of the slope of the tangent (coefficient A_1) at the beginning of the fitted curve, as compared with the developed method. The inaccuracy in the conventional method can be attributed to a lower order polynomial (5^{th}) used and a longer duration of curve fit (2.5 s - comparable to the one used in [13]). Hence, from these observations, a conclusion can be made that virtual inertia from WTG is unlikely to affect the estimation of the synchronous inertia in the developed method.

With the correct estimation of synchronous inertia in a microgrid system, the operators can take various measures to maintain a stable operating frequency in the system. Firstly, system operators can target to maintain a minimum level of synchronous machines operating in the system so that the microgrid does not experience RoCoF inadequacy and limit violations. Moreover,

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the information of the synchronous inertia in the system can also help system operators to design virtual inertia services that will cater to specific system requirements. As the authors in [34] have pointed out, the system operation target is not a level of synchronous or non-synchronous inertia, but an outcome of stable frequency. With the measured value of H_{est}, the base frequency response from the synchronous machines can be predicted, and system designers can exploit this information to further fine-tune the virtual inertia controller parameters for specific network/system conditions.

To estimate the nonsynchronous inertia component, on the other hand, there are two potential options. One option is to calculate the value of inertia constant with a completely new estimation method to analyze the measured frequency response. The other is to estimate the total energy that is released before the system frequency starts its recovery process. In either case, the value of the estimated inertia will be dependent on the type of virtual inertia control employed for a given renewable energy source. Although each of the renewable sources has a specific amount of releasable kinetic energy, the profile in which the energy is released varies with the control that is employed. Hence, without information about the amount of available releasable energy and the virtual inertia control employed in each of the renewable generations, estimation of nonsynchronous inertia would be rather complex. The authors of this paper are currently working towards developing a methodology for accurate estimation of the nonsynchronous inertia.

VI. Conclusion

An improved inertia estimation method for estimating the value of inertia of a microgrid system is proposed in this paper. Improvements are made in the conventional swing equation-based estimation method to improve the accuracy of the estimate. At the outset, estimation study is carried out on a test microgrid system that has only synchronous generations. Subsequently, renewable sources in the form of Type 3 and Type 4 wind turbines, and PV arrays are integrated into the microgrid to perform further estimations. The results show an accurate estimate of inertia without any virtual inertia support in place. The study is followed by implementation of virtual inertia control for DFIG WTGs. Estimation of inertia with virtual inertia support from WTG is then carried out. The results of the estimation show that the improved estimation method can correctly estimate the inertia provided by synchronous machines only, thus allowing accurate synchronous inertia estimation in renewable energy integrated system. Finally, these results pave the way to differentiate between estimations of synchronous and nonsynchronous inertia separately for a microgrid system.

Appendix A

The parameters of the synchronous generator used in the study, which includes model of synchronous machine, governor, and excitation system are provided in Table IV.

TABLE IV
Ratings and Parameters of Synchronous Generators

Generator parameters	
Nominal power (DG 1-3)	15; 2 & 1.5 (MVA)
Line-to-line voltage (DG 1-3)	69; 13.8 & 13.8 (kV)
Inertia constant (DG 1-3)	2.2; 2.45 & 2.45 (s)
d-axis reactance (X_d, , $X_{d'}$, $X_{d''}$)	1.305, 0.296, 0.252 (pu)
q-axis reactance (X_q, , $X_{q'}$, $X_{q''}$)	0.474, 0.243, 0.18 (pu)
Time constants ($T_{d'}$, $T_{d''}$, $T_{qo'}$)	3.7, 0.05, 0.05 (s)
Diesel Engine Governor	
Regulation gain	40
Regulation time constants (T_1, T_2, T_3)	0.01,0.02, 0.2 (s)
Engine time delay	0.014 s
Excitation System	
Voltage Regulation gain and time constant	200, 0.02 s
Exciter gain and time constant	1, 0.8 s

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