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A novel smart meter technique for voltage and current estimation in active distribution networks

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ABSTRACT

For distribution network operators to make effective decisions about real-time applications, they should have complete knowledge of all system variables. However, measuring all variables is infeasible due to the large number of system buses and the consequently high cost of measurement devices. Network operators are thus in serious need of methods that can estimate system voltages and currents with only a few measuring devices. This paper presents a novel voltage, current, and power loss estimation technique for distribution networks characterized by a high level of distributed generation (DG) penetration. The proposed method is based on online measurements from smart meters (SMs) placed at a few selected locations in addition to the measurements from DGs production meters; the estimation is derived without any pseudo measurements. The ingenuity of the proposed technique is that the SM locations are dependent on the network topology only, which means that their locations remain unchanged regardless of penetration levels and/or DG injection points. The proposed technique also includes consideration of variations in X/R ratios and laterals. The developed algorithm was implemented and tested on three radial distribution feeders to show the capability of the proposed technique for estimation for balanced as well as unbalanced distribution networks. The results of a comparison with the actual load flow demonstrate the accuracy and effectiveness of the new technique.

1. Introduction

Distribution networks are swiftly becoming active because of the proliferating integration of distributed generators (DGs). Once connected to the network, DGs boost the system voltage profile, enhance power quality by improving supply continuity, reduce undesirable gas emissions, and decrease system upgrading costs due to the deferral of new investments [1,2]. However, excess DG integration could have an adverse effect on a distribution network. High DG penetration creates problems related to reverse power flow, fault current increments, thermal capacity limit violations in the lines, and steady state voltage rises [3].

If they are to be aware of voltage rise and thermal capacity violation problems, system operators require online measurements of all system voltages and currents. Measurements of voltages and currents enable a system operator to take corrective action to eliminate problems arising from excess DG penetration. However, the installment of intelligent measuring devices at all system buses might not be cost-effective. A need thus exists for estimation techniques that can determine system voltages and currents with only a few meter measurements.

Many researchers have developed measurement schemes that facilitate voltage assessment in distribution grids. Their studies can be classified into two main categories. The first category is concentrated on adapting the conventional state estimation methods employed in transmission grids for use in distribution grids [4–12]. The second category is focused on the placement of measuring devices for the assessment and calculation of system voltages [13–15]. Although both categories are targeted at the estimation of distribution system voltages, they differ in a number of aspects, as explained in the following sections.

1.1. Distribution system state estimation

State estimation (SE) denotes "a data processing algorithm for converting redundant meter readings and other available information into an estimate of the state of an electric power system" [4]. In a distribution system, real-time measurements are usually limited, which means that, network observability is impossible without pseudo and virtual measurements. The use of pseudo measurements is a crucial characteristic of distribution system SE. Pseudo power injection measurements at feeder buses can be determined based on customer billing data and typical load profiles or could even be defined as Gaussian

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distributions [5]. However, customer power-consumption behavior could change drastically due to power generated by customer-owned DGs. Since a customer can thus be a producer, establishing consumption behavior based on pseudo measurements is no longer valid [4]. For large distribution networks with thousands of buses and different load types, an accurate determination of load profiles for all system buses becomes extremely difficult.

A method for placing voltage measurement devices for distribution system estimation was presented in [7] and [8]. To reduce unmeasured voltage magnitude deviations, a specific number of measurement devices were placed on busbars. However, this method was performed offline and cannot estimate currents or power losses. The authors of [10] presented an SE method for low voltage distribution networks based on the placement of smart meters (SMs) in order to improve the uncertainty associated with the estimated voltage. However, this method assumed that 50% of customers and DGs are equipped with SMs that can transmit power injection measurements and voltage measurements.

1.2. Real-Time voltage estimation

Unlike traditional SE, real-time methods rely on only a few real-time voltage measurements and then employ different procedures to assess the distribution system voltage profile. The lack of redundant meter measurements prevents these methods from being able to detect bad data or to identify network configuration errors. Since they are unable to estimate the voltage at all system buses, such methods estimate the voltage profile based on a determination of the global maximum and minimum system voltages. The authors of [13] and [14] introduced a strategy for voltage estimation and control via the placement of remote terminal units (RTUs) at DG and terminal buses. Their strategy was aimed at estimating global maximum and minimum system voltages and at controlling the steady state voltage rise problem through the substation voltage regulator. This approach is applicable only on feeders without laterals and with fixed X/R ratios for all line segments. As well, the RTUs in the control scheme must measure the voltage at a neighboring bus, which might be physically difficult. A further drawback is that the study reported in [13] was unable to estimate feeder currents in order to judge whether they exceed feeder capacity with increased DG penetration. A subsequent study [15] suggested an amended version of this scheme, which needed fewer measurements for the estimation of the global extreme voltage. This approach reduces the communication and calculation burdens on the RTUs, but the other disadvantages mentioned still apply.

To summarize, distribution system SE methods are adequate when redundant meter measurements are obtainable. Enough billing and load profile historical data must also be available so that sufficient pseudo measurements can be generated to overcome the lack of observability and to allow the detection and identification of bad data. For large distribution systems, in which only very few real-time measurements are available and insufficient billing records or load profile data exist, real-time methods are candidate alternatives to traditional SE methods. Real-time methods could be used for obtaining voltage profile estimations based on the measurements available. However, these methods provide only an approximate voltage profile and are unable to estimate branch currents and system power losses.

This paper presents a novel technique of voltage, current, and power loss estimation in active distribution networks. The new method eliminates the disadvantages of real-time estimation techniques and also overcomes the lack of observability that occurs due to limited measurements. The proposed method is dependent on real-time measurements from SMs placed at a few locations that remain fixed regardless of the number and placement of DGs. Moreover, the proposed method utilizes the active and reactive power measurements from production meters located at DGs buses. In the proposed approach, the meters communicate the variables they have measured to a central control unit (CCU) that can estimate the complete voltage profile of the feeder as well as all line currents and system losses. The proposed method offers an effective alternative to SE in the case of insufficient pseudo measurements and a lack of observability. The main contributions of the scheme presented here are as follows:

1) The method is suitable for any radial distribution feeder configuration with an unlimited number of laterals, and it can execute the estimation for a variety of X/R ratios.
2) The SM locations are selected based only on the network topology. These locations are unaffected by new DG installation.
3) The limited number of SMs used in the proposed method significantly reduces communication congestion and delays.
4) With the proposed method, the number of SMs required for a large number of DGs is much lower than with other real-time voltage assessment methods.

The proposed estimation method was implemented and tested on the 33-bus and 69-bus test feeders. For validation purposes, the results were compared with actual load flow results. The findings and accompanying discussion confirm the effectiveness of the proposed scheme.

2. Structure of the proposed system

In order to gain more benefits of the existing smart meters, SMs should be employed in multiple functions in addition to the conventional energy consumption management. Although nowadays SMs are mainly employed for billing purposes with communication intervals around 10 min, they could provide the flexibility needed for new functionalities. Several meter manufacturers allow real-time readout of SMs internal instrumentation values with fast reporting rates less than one minute [16]. These internal measurements prolong the SMs functionalities to a new horizon. Thus, the new generation of SMs is capable of measuring the voltage, active power and reactive powers and communicates them with high reporting rates. Moreover, continuous developments are carried out to enhance SMs reporting rates and to increase their functionalities for cost-benefit ratio improvement. These enhancements make SMs suitable for the proposed technique.

2.1. Meters placement strategy

The general strategy for meters placements includes the placement of SMs at every branching bus of the system (each branching bus is the start bus of a lateral) and at all end buses of all system laterals. Moreover, SMs (work as production meters) are placed at DGs buses and reports the DGs power generation to the CCU. As can be seen in the sample system shown in Fig. 1, structure of the proposed system consists of an SM at every branching bus and at each terminal bus of the feeder laterals.

2.2. SMS and CCU responsibilities

Fig. 2 depicts the function of each SM, which is responsible for the following:

1) Measuring the voltage magnitude at its bus;
2) Measuring the active and reactive powers in the upstream and downstream lines connected directly to its bus;
3) Communicating its measurements to the CCU.

The CCU located at the substation bus is responsible for the following:

1) Knowing the distribution network topology and the impedance of each line section;

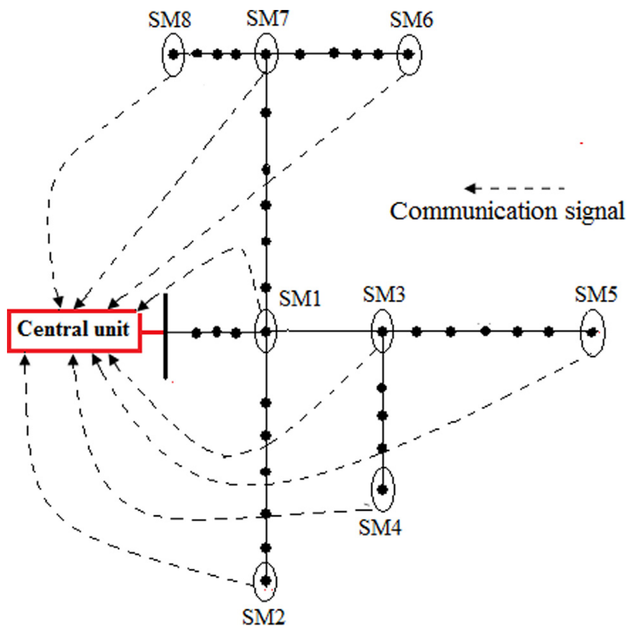

Fig. 1. Proposed system structure.

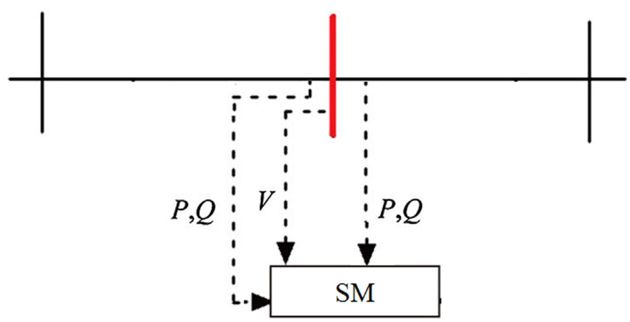

Fig. 2. SM responsibilities.

2) Estimating the branch power flows based on the data received from the SMs and the network topology;
3) Estimating the complete voltage profile, branch currents, load power, and power losses, beginning with the far laterals and ending with the feeder stem.

3. Voltage and current calculations in unbalanced network

For the three-phase voltage and current calculations of an unbalanced distribution system, the mutual impedances are modeled as current controlled voltage sources along the sections of the lateral as shown in Fig. 3. For the part of power system shown, if the three phase voltages at bus #*i* and the three phase complex power flows from bus #*i* to bus #*j* are measured, the exact voltages at downstream bus (i.e. bus #*j*) could be calculated using (1) and (2)

$$I_{a,ij} = (S_{a,ij}/V_{a,i})^{*} I_{b,ij} = (S_{b,ij}/V_{b,i})^{*} I_{c,ij} = (S_{c,ij}/V_{c,i})^{*} \quad (1)$$

$$V_{a,j} = V_{a,i} - I_{a,ij}Z_{aa,ij} - I_{b,ij}Z_{ab,ij} - I_{c,ij}Z_{ac,ij} V_{b,j} = V_{b,i} - I_{b,ij}Z_{bb,ij} - I_{a,ij}Z_{ba,ij} - I_{c,ij}Z_{bc,ij} V_{c,j} = V_{c,i} - I_{c,ij}Z_{cc,ij} - I_{a,ij}Z_{ca,ij} - I_{b,ij}Z_{cb,ij} \quad (2)$$

where, $V_{abc,i}$, and $V_{abc,j}$ are the complex three phase voltages at buses #*i*, #*j* respectively; $S_{abc,ij}$ and $I_{abc,ij}$ is the complex three phase power and current flow from bus# *i* to bus# *j* respectively.

If the three phase complex power flows from bus #*j* to bus #*k* are estimated, the voltages at bus #*k* could be estimated based on complex power flows estimation and calculated values of voltages at bus #*j*. this procedure could be continued until reach the terminal bus of the lateral. Moreover, if the voltages at terminal bus and the power flows toward terminal bus are measured all upstream buses voltages and line currents could be calculated if a proper estimation of power flows exists. The next section describes how power flow estimation and final estimations of voltages and currents could be done iteratively.

4. The proposed estimation technique

The proposed technique comprises two major stages; the first is the initial estimation of the system voltage profile and branch currents. The second stage is an iterative algorithm aimed at refining the voltage and current estimation obtained in the first stage. Both stages are summarized in the flow chart presented in Fig. 4 and discussed as follows.

4.1. Initial voltage profile and branch current estimation

The initial estimation of one distribution feeder lateral with multiple DGs connected, as shown in Fig. 5, is determined based on the following steps:

1. The SM connected to bus #m (SM1) measures the magnitude of its bus voltage ($V_{abc,m}$) and the active and reactive power flows toward the downstream bus of each of the three phases.
2. For each of the three phases, the sum of the total loads of the feeder lateral downstream to bus #m (S_f) is calculated by knowing all of the lateral DGs powers and SM1 measurement as follows:

$$S_f = S_{m,out} + S_G \quad (3)$$

where $S_{m,out}$ is the downstream complex power flow measured by the SM connected to bus #*m*, and S_G is the sum of the complex power values for all of the DGs between the two SMs. The complex DG power is measured by meters placed at the DG buses and is then communicated to the CCU.

3. SM1 communicates its measurements to the CCU. As an initial guess, the CCU overcomes the lack of observability by assuming equal sharing of S_f among all buses downstream from SM1 up to SM2 using (4) to estimate the load power values. This assumption is used as an initial guess only and changes during the course of the iterative algorithm presented in Section 4.2.

$$S_{L,m+1} = S_{L,m+2} = \ldots S_{L,n} = S_f/(n-m) \quad (4)$$

where $S_{L,m+1}$, $S_{L,m+2}$, and $S_{L,n}$ are the estimated complex load power, and (*n*-*m*) is the number of buses downstream from SM1.

4. The CCU calculates the branch power flows using the estimated load power values and the network topology.
5. The CCU performs the first estimation by calculating the branch currents and voltage profile using (1) and (2), taking the voltage angle of bus #m as a reference (i.e. $\angle V_{a,m} = 0$, $\angle V_{b,m} = -120°$, $\angle V_{a,m} = 120°$).
6. The SM connected to bus #n (SM2) measures the magnitude of its bus voltage and the active and reactive power flows from the upstream bus. The measured complex power flow ($S_{n,in}$) is independent of the DG power.
7. SM2 communicates its measurements to the CCU, which estimates the load power by considering equal load power values match the measured power. This assumption represents a first guess used only for the initial estimation step.

$$S_{Lm} = S_{L(m+1)} = \ldots S_{Ln} = S_{n,in} \quad (5)$$

8. The CCU performs a second estimation based on the SM2 readings by calculating the branch currents and bus voltages using (5) and (6), beginning with bus #n and ending at bus #m, taking the

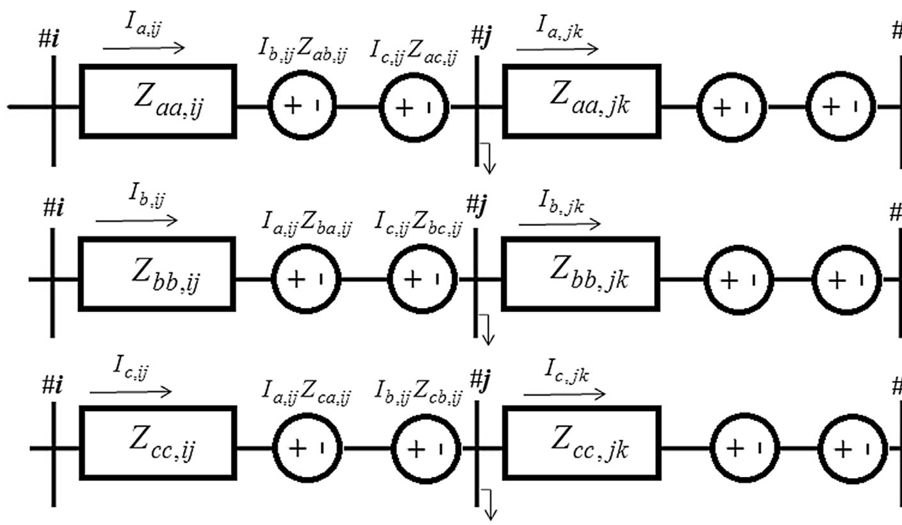

Fig. 3. Three phase equivalent circuit of branch.

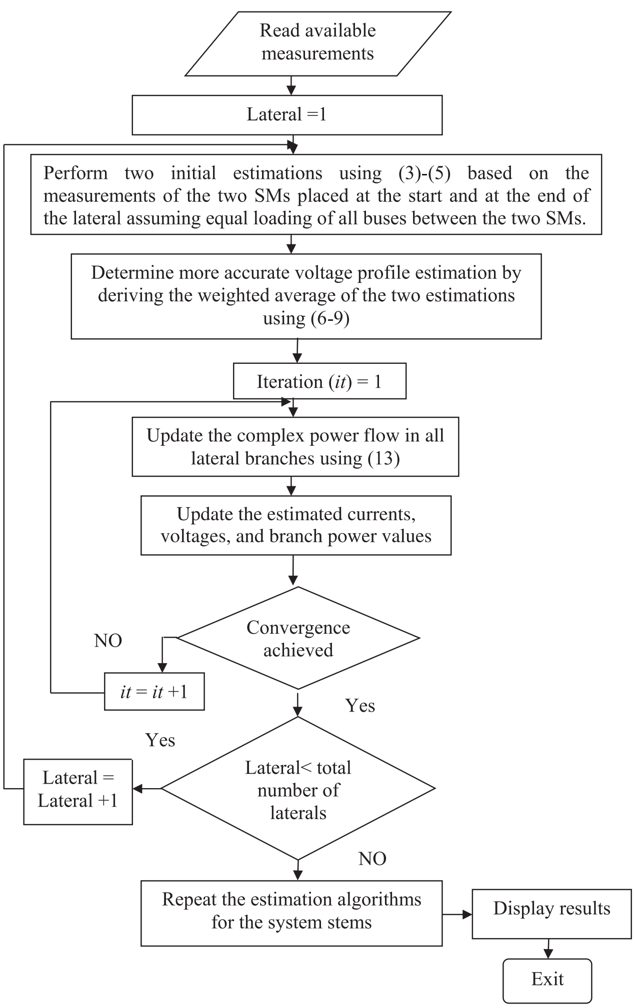

Fig. 4. Flow chart of the proposed algorithms.

voltage angle of bus #n as a reference (i.e. $\angle V_{a,n} = 0$, $\angle V_{b,n} = -120°$, $\angle V_{c,n} = 120°$).

9. The CCU updates the angles of all voltages and currents from the second estimation by subtracting the voltage angle of bus #m (obtained from the second estimation) from each angle of the second-estimation voltage or current. This step ensures one reference angle for both estimations: the bus #m voltage.
10. The CCU determines a more accurate voltage profile estimation by deriving the weighted average of the two estimations, as follows:

$$V_{est}^{abc}(i) = V_{est,m}^{abc}(i) \times K_{est1} + V_{est,n}^{abc}(i) \times K_{est2} \tag{6}$$

where $V_{est}^{abc}(i)$ are the updated estimated voltages at general bus $\#i$ for the three phases, $V_{est,m}^{abc}(i)$ are the estimated voltages at bus $\#i$ based on the 1st estimation, and $V_{est,m}^{abc}(i)$ are the estimated voltage at bus $\#i$ based on the 2nd estimation. K_{est1} and K_{est2} are weights that changes as described in (7) and (8):

$$K_{est1} = \left(\frac{n-i}{n-m}\right) \tag{7}$$

$$K_{est2} = \left(\frac{i-m}{n-m}\right) \tag{8}$$

11. The CCU determines a more accurate estimation for the branch currents by obtaining the weighted average:

$$I_{est}^{abc}(i) = I_{est,m}^{abc}(i) \times K_{est1} + I_{est,z}^{abc}(n) \times K_{est2} \tag{9}$$

where $I_{est}^{abc}(i)$ is the updated estimated branch currents flowing to bus #i for three phases, $I_{est,m}^{abc}(i)$ is the estimated branch currents based on the SM1 readings, and $I_{est,n}^{abc}(i)$ is the estimated branch current based on the SM2 readings.

The estimation algorithm can be generalized for feeder stems with some laterals originating from the buses, such as the feeder stem shown in Fig. 6, which originates from bus $\#m$ and terminates at bus $\#n$. The same algorithm performs the estimation, but with (3) changed to (10):

$$S_{m,out\,2} = S_f - S_G + \sum S_{n,out} \tag{10}$$

where $S_{m,out2}$ is the measured complex power flow downstream toward bus $\#n$, and $\sum S_{n,out}$ is the sum of the total complex power flows downstream toward bus $\#n$.

A further change is the modification of (7)–(11):

$$S_{Lm} = S_{L(m+1)} = \ldots S_{Ln} = S_{n,in} - \sum S_{n,out} \tag{11}$$

If a DG is connected to the downstream bus where the SM is located, the DG power should also be added to the measured power by this SM. Eq. (11) thus becomes (12):

$$S_{Lm} = S_{L(m+1)} = \ldots S_{Ln} = S_{n,in} + S_G - \sum S_{n,out} \tag{12}$$

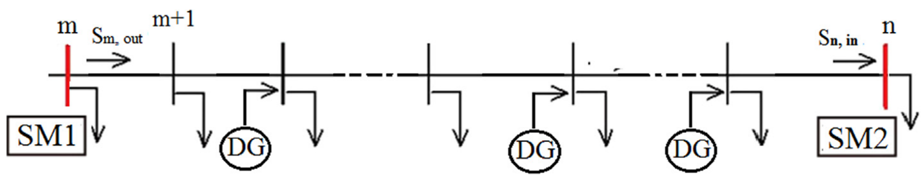

Fig. 5. Sample distribution feeder lateral.

4.2. Final estimation

To estimate the complete voltage profile and line currents of the entire distribution network accurately, the CCU performs the following algorithm steps:

1) Beginning from the feeder farthest lateral, the two SMs located at the start and end terminals of the lateral communicate their measurements to the CCU.
2) The CCU performs the initial voltage and current estimations by following steps 1–11 from Section 4.1.
3) The CCU updates the complex power flow in all lateral branches as follows:

$$S_{est}^{abc}(i) = V_{est}^{abc}(i) \times (I_{est}^{abc}(i))^* \tag{13}$$

It should be noted that this step modifies the equal allocation of loads assumed in the initial guess.

4) The CCU updates the estimated currents, voltages, and branch power values using (1), (2), and (6)–(9) by performing two estimations. The first considers the start bus of the lateral as a reference and calculates the currents and voltages up to the end terminal. The second estimation takes the end bus as a reference and backward calculates the currents and voltages up to the start terminal. The second-estimation angles are updated as described in step 9, Section 4.1.
5) Steps 4 and 5 are repeated until convergence: the maximum differences in voltages and currents between two consecutive iterations are less than the preset tolerance. It should be noted that repeating step 4 changes the load values in each iteration until the solution represents an accurate estimation of the load values.
6) Steps 2–6 are repeated for all other laterals.
7) Once all laterals have been completed, steps 2–6 are repeated for all feeder stems, starting from the farthest and ending at the substation bus main stem in order to obtain a complete estimation of the system voltage profile and all branch power values.
8) The voltage and current angles of all of the laterals are updated based on the angles estimated when the substation bus voltage is considered as the reference bus.
9) The CCU estimates the total active power losses of N bus feeder as follows:

$$P_{loss} = \sum_{\varphi=a,b,c} \sum_{i=1}^{N-1} |I_{est}^{\varphi}(i)|^2 R^{\varphi}(i) \tag{14}$$

where $R^{\varphi}(i)$ is the resistance of the line segment connecting buses $(i-1)$ and i for each of the three phases.

5. Systems studied

The proposed technique is applicable for any radial distribution feeder. For practical distribution systems with thousands of buses, the system must be divided into zones, with each zone containing its own CCU responsible for the estimations for that zone only. The CCU also communicates its results to a system operator and sends operator decisions to any devices connected to its zone. Acquiring complete system estimation in as short a time as possible requires parallel processing of all CCU estimations.

To test the efficiency of the proposed approach, three separate zones were considered. The first and second zones were assumed to have the same topologies and impedance values as the 33-bus and 69-bus test feeders [17], respectively. These two feeders were selected for study because they represent practical distribution feeders with variable X/R ratios and several laterals. The 33-bus feeder is characterized by high line impedance values, with an X/R ratio that is almost constant for the majority of buses. The total connected active power load is 3715 kW and the reactive power is 2300 kVAr. The average active and reactive power loads for all buses are thus 116 kW and 71.87 kVAr, respectively. The 69-bus feeder was chosen because of its large number of laterals with different lengths, its inherent variations in line impedance values, and its large range of line X/R ratios, all of which make it ideal for testing the capabilities of the proposed method. It has a total connected active power load of 3802.2 kW and a reactive power of 2694.6 kVAr, which means that the average active and reactive power loads for all buses are 55.91 kW and 39.62 kVAr, respectively. SM locations were determined based on the scheme discussed in Section II. Fig. 7 and Fig. 8 illustrate the 33-bus and 69-bus feeders after placement of the SMs at the circled buses. It should be noted that if two SMs exist on two successive buses on the feeder stem (e.g., buses #3 and #4, and buses #8 and #9 on the 69-bus feeder), they cannot be replaced by a single SM on any one bus. For very short end laterals (e.g., laterals 8–59, 11–68, and 12–69 on the 69-bus feeder), the SM at the terminal bus could be removed because one SM at the beginning of such short

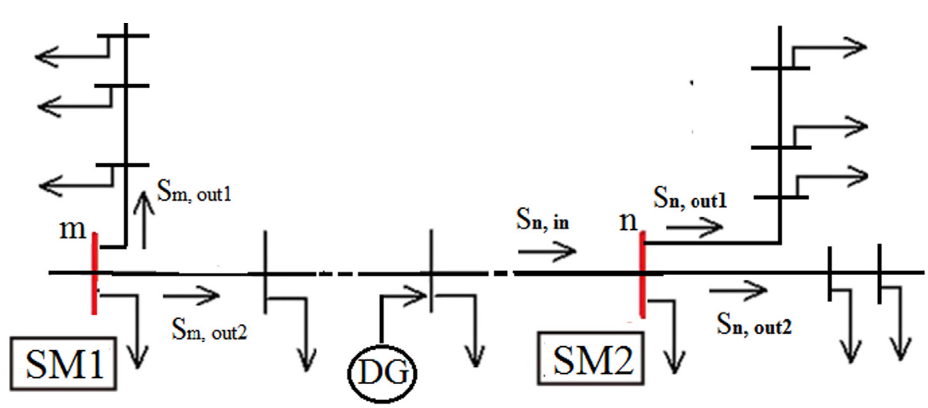

Fig. 6. Sample distribution feeder stem.

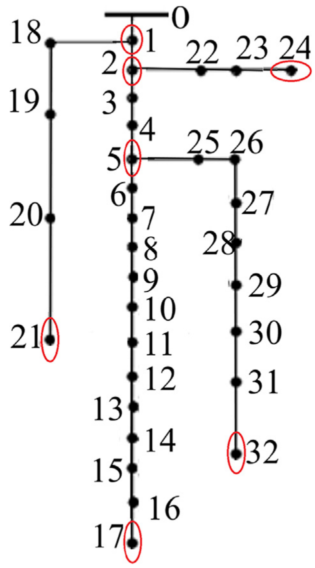

Fig. 7. Layout of the 33-bus feeder following SM placement.

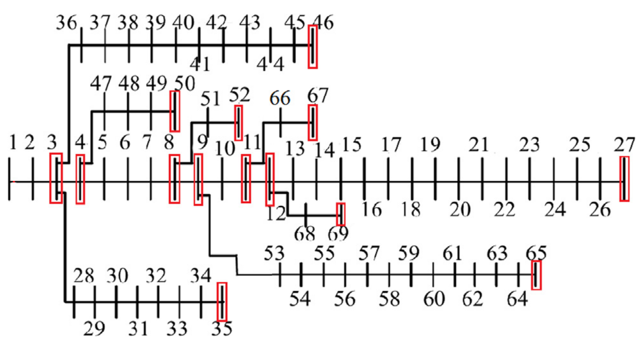

Fig. 8. Layout of the 69-bus feeder following SM placement.

laterals is sufficient for estimating the currents and voltages.

The third zone was assumed to have the same topologies and impedance values as the IEEE 34 bus unbalanced feeder. This complicated feeder is an actual feeder located in Arizona, with a nominal voltage of 24.9 kV. It is characterized by very lengthy lines, unbalanced impedances, and combinations of three phase and single phase branches. The locations of the SMs are determined; SMs utilized are those placed at each branching bus and each end-terminal bus. However, for reducing the communication burden and increasing estimation speed, SMs placed at buses 4, 13, 17, 21, 22, 23, 31, and 33 are not used as the SMs upstream to them are able to determine exactly the voltages at their buses and current flowing to them (e.g. SM at bus #3 is able to determine exactly voltage and current at bus #4; thus, no need for taking measurements of SM at bus #4). Fig. 9 shows the renumbered IEEE 34

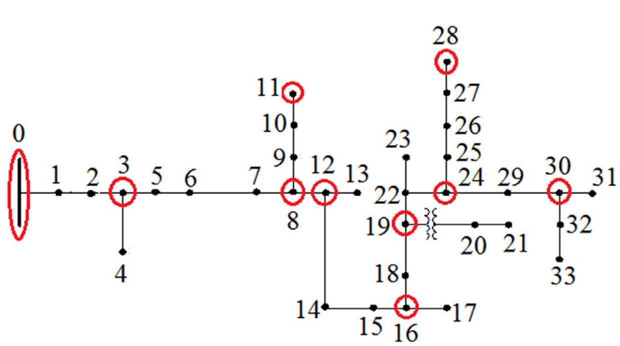

Fig. 9. Layout of the 34-bus feeder after SMs placement.

Table 1
Summary of the 33-Bus feeder test cases.

Test case #	Variation in loads	DG locations	DG power, in p.u.
1	10%	–	–
2	20%	–	–
3	50%	–	–
4	100%	–	–
5	10%	6, 9, 14	0.05 each
6	10%	6, 9, 14	0.1 each
7	20%	6, 9, 14	0.1 each
8	10%	11, 20, 22, 27	0.1 each
9	20%	11, 20, 22, 27	0.1 each
10	10%	3, 6, 9, 14, 19, 23, 29	0.05 each
11	20%	3, 6, 9, 14, 19, 23, 29	0.1 each
12	50%	3, 6, 9,14, 19, 23, 29	0.1 each

bus feeder after placement of SMs on encircled buses.

6. Test cases

The proposed scheme and estimation method was implemented in MATLAB and tested on the 33-bus, 69-bus, and the IEEE 34-bus test feeders. A total of 32 cases (twelve for each of the 33-bus and the 69-bus test feeder and eight for the IEEE 34-bus unbalanced feeder) were tested in order to evaluate how efficiently the proposed scheme could provide accurate estimations of the voltage profile, feeder line currents, and power losses. The bus loads of each feeder were selected randomly within a specific range around the average loading condition stated in Section 5. Load variations of 10% (i.e., an average feeder load ± 5%), 20%, 50%, and 100% were considered in the test cases. To demonstrate the estimation accuracy of the proposed method, a variety of DG penetration scenarios were assumed with different numbers of DGs located at different buses on different laterals. Tables 1–3 provide a summary of the test cases details. For all cases, the results obtained using the proposed method were compared to actual results produced by a load flow algorithm based on a backward/forward sweep. The actual load flow was used only for comparison purposes; load flow is unsuitable for real-time online operation because the values of all bus loads are required. In contrast, the proposed method needs only a limited number of measurements.

To compare the actual and estimated values, each test case was repeated ten times with random loads each time, and the maximum error between the actual and estimated voltages and currents for all buses was calculated for each run.

Table 2
Summary of the 69-bus feeder test cases.

Test case #	Variation in loads	DG locations	DG power, in p.u.
13	10%	–	–
14	20%	–	–
15	50%	–	–
16	100%	–	–
17	10%	19, 46, 50, 65	0.05 each
18	20%	19, 46, 50, 65	0.05 each
19	20%	7, 14, 17, 20	0.05 each
20	20%	7, 14, 17, 20	0.1 each
21	10%	8, 15, 21, 25, 33, 39, 44, 48, 58, 63.	0.05 each
22	10%	8, 15, 21, 25, 33, 39, 44, 48, 58, 63.	0.1 each
23	20%	8, 15, 21, 25, 33, 39, 44, 48, 58, 63.	0.1 each
24	50%	8, 15, 21, 25, 33, 39, 44, 48, 58, 63.	0.05 each

Table 3
Summary of the IEEE 34-bus feeder test cases.

Test case#	25	26	27	28
Load variations (%)	20	50	20	20
DGs Locations, types.	N/A	N/A	#6, 3ph. #10, 1ph.a #25, 3ph.	#6, 3(1ph) #10, 1ph.a #25, 3(1ph)
DGs powers (kW)	0	0	100/ph 250/ph.a 150/ph	100/ph.a,150/ph.b,c 250/ph. a 150/ph.a,200/ph.b,c
Test case#	**29**	**30**	**31**	**32**
Load variations (%)	100	20	20	20
DGs Locations, types.	N/A	#6, 3ph #10, 1ph,a #32, 3ph	#7, 3ph #9, 1ph, a #15, 3ph #25, 3ph	#7, 3 × (1ph) #9, 1ph, a #15, 3 × (1ph) #25, 3 × (1ph)
DGs powers (kW)	0	200/ph 500/ph,a 300/ph	100/ph 150/ph,a 100/ph 100/ph	200/ph.a,100/ph,b,c 250/ph. a 200/ph.a,100/ph,b,c 200/ph.a,100/ph,b,c

7. Results and discussions

7.1. Results for the 33-Bus feeder

The estimation scheme starts with lateral 5–17. The SM connected to bus #5 first communicates its measurements to the CCU, which calculates the branch power and estimates voltages. The SM located at bus #17 then performs the same task, and the CCU estimates the lateral branch current and voltage profile from the perspective of SM located at bus #17. In the final step, the CCU utilizes the estimation algorithm explained in Section 4. The second lateral to be analyzed is lateral 5–32 followed by lateral 2–24 and then lateral 1–21. After all laterals are evaluated, the algorithm analyzes the feeder stem (i.e., from bus #0 to bus #5). It should be noted that the angles of all lateral voltages and currents are updated following the estimation of the stem bus angles. (e.g., the voltage and current angles of laterals 5–32 and 5–17 are updated by adding to each of their angles the voltage angle of bus #5, obtained from the voltage estimation for stem 0–5).

For the implementation of the 33 bus feeder test cases, the substation voltage was adjusted to 1.05p.u. and the base power was considered the sum of the total feeder active power values. The results of each test case are the complete estimated voltage profile of the feeder nodes, all line currents, and the total system power losses. All results were compared to actual results obtained from load flow measurements. Figs. 10 and 11 show the estimated and actual voltage profiles, excluding the substation bus voltage, for test cases #4 and #12, respectively. These two cases have been chosen in order to highlight the effectiveness of the voltage estimation when the loads and DG penetration vary greatly. Figs. 12 and 13 provide a further sample comparison between the estimated and actual branch currents for test case #9 and #12, respectively; each branch is named based on its end bus. The results reveal the close agreement of the actual and estimated profiles, which validates the effectiveness of the proposed scheme for varied DG penetration levels. A sample of the actual and estimated voltage angle results for test case #4, which involves a high degree of load variation, is presented in Table 4. The estimated and actual voltage angles are clearly very close regardless of the amount of load variation, which proves the efficacy of the proposed method with respect to estimating feeder currents.

Table 5 indicates the maximum voltage and current errors as well as the power losses for the twelve test cases. Moreover, the average number of iterations, of all runs of all laterals and stems, required for the convergence is presented in the table. These results demonstrate the

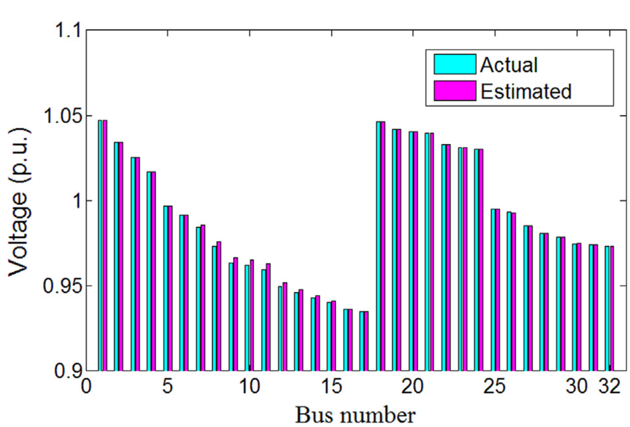

Fig. 10. Complete voltage profile, 33-bus feeder, test case #4.

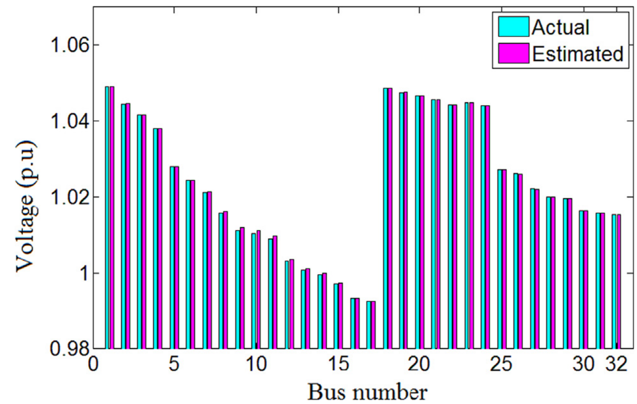

Fig. 11. Complete voltage profile, 33-bus feeder, test case #12.

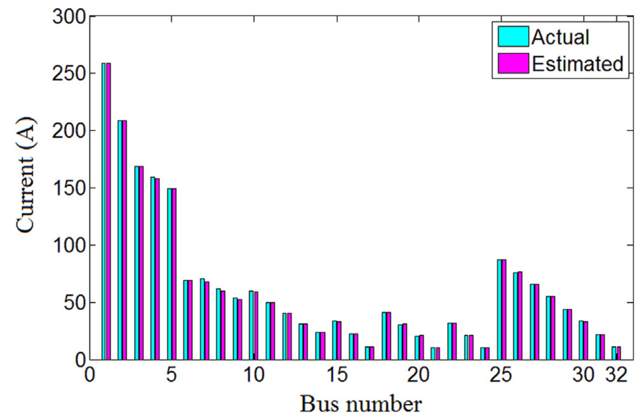

Fig. 12. Complete branch currents, 33-bus feeder, test case #7.

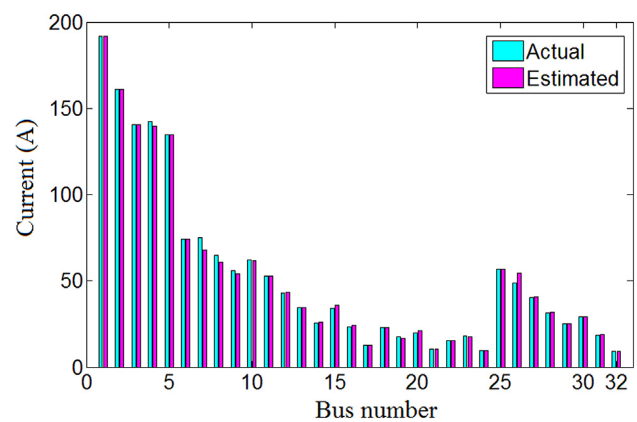

Fig. 13. Complete branch currents, 33-bus feeder, test case #12.

Table 4
Summary of the 33-bus feeder results for test case #4.

	Proposed	Load flow		Proposed	Load flow
Bus number	Voltage angle (rad)	Voltage angle (rad)	Bus number	Voltage angle (rad)	Voltage angle (rad)
1	0.0002	0.0002	21	−0.0004	−0.0009
2	0.0011	0.0011	22	0.0010	0.0010
3	0.0018	0.0018	23	0.0006	0.0009
4	0.0025	0.0024	24	0.0005	0.0007
5	−0.0007	−0.0008	25	−0.0006	−0.0006
6	−0.0054	−0.0054	26	−0.0002	−0.0005
7	0.0035	−0.0037	27	−0.0014	−0.0019
8	−0.0041	−0.0045	28	−0.0022	−0.0027
9	−0.0044	−0.0052	29	−0.0021	−0.0026
10	−0.0040	−0.0049	30	−0.0031	−0.0036

Table 5
Summary of the 33-bus feeder test case results.

Test case #	Max. voltage error (p.u.)	Max. current error (p.u.)	Estimated power loss (kW)	Actual power loss (kW)	Average number of iterations required
1	0.000117	0.0013	218.81	218.74	12
2	0.000144	.0035	214.40	214.53	14
3	0.000536	0.0275	213.71	214.91	13
4	0.0034	0.0654	217.86	222.42	16
5	0.000084	0.0031	142.30	142.51	15
6	0.000135	0.0033	98.187	98.239	12
7	0.000186	0.0078	98.329	99.07	14
8	0.000071	0.0025	121.65	121.52	13
9	0.000125	0.0066	124.51	123.45	15
10	0.000206	0.005	114.14	113.83	17
11	0.000389	0.0117	65.633	64.869	16
12	0.000721	0.0206	71.035	72.279	17

validity of the estimates provided by the proposed method in the presence of large load variations. The proposed scheme produced an accurate voltage estimation in all cases, with an average estimation time of 43.7 s, thus ensuring its suitability for real-time applications. As can be deduced from cases #1 and #4, a high amount of load variation leads to less accurate results from the proposed method. A further comparison of case #6 to case #8 and case #7 to case #8 reveals that increasing DG penetration at the same lateral, regardless of the total DG penetration, results in a lower degree of accuracy. It could be concluded that the estimation is less accurate in cases with high levels of load variation and very high DG power injection. However, in practical conditions, load variations between feeder buses rarely reach very high values. Very high DG power injection is also restricted due to technical constraints such as reverse power, the voltage rise problem, and line capacity constraints. The proposed method is thus adequate for the practical operation of active distribution networks.

7.2. Results for the 69-Bus feeder

Details of the 12 cases applied for testing the proposed method using the 69-bus feeder are listed in Table 2, and the results are summarized in Table 6. The average estimation time is 142.4 s, which is suitable for online operation. The results reveal the excellent estimation efficiency of the proposed method for a variety of cases. Fig. 14 provides a comparison of the complete voltage profile for test case #24 with the actual results; the voltage values are almost identical for the majority of the buses, demonstrating that the proposed method can deal with feeders that have extreme variations in impedance and X/R values. Fig. 15 indicates the branch currents for test case #24; the results prove the estimation accuracy of the proposed method for cases with high levels of load variation (50%) and DG penetration (0.5p.u.).

Table 6
Summary of the 69-bus feeder test case results.

Test case #	Max. voltage error (p.u.)	Max. current error (p.u.)	Estimated power loss (kW)	Actual power loss (kW)	Average number of iterations required
13	0.00008	0.0046	96.79	96.91	21
14	0.00012	0.0101	99.16	99.51	24
15	0.00027	0.0161	101.52	101.91	23
16	0.00038	0.0490	91.44	90.32	26
17	0.00054	0.0178	69.72	69.81	27
18	0.00061	0.0192	68.25	68.55	24
19	0.00010	0.0075	53.91	53.73	22
20	0.00058	0.0418	44.21	46.87	21
21	0.00097	0.0543	38.56	38.40	24
22	0.0016	0.086	46.30	45.59	23
23	0.0023	.109	45.24	47.09	26
24	0.0017	0.0748	37.48	36.93	22

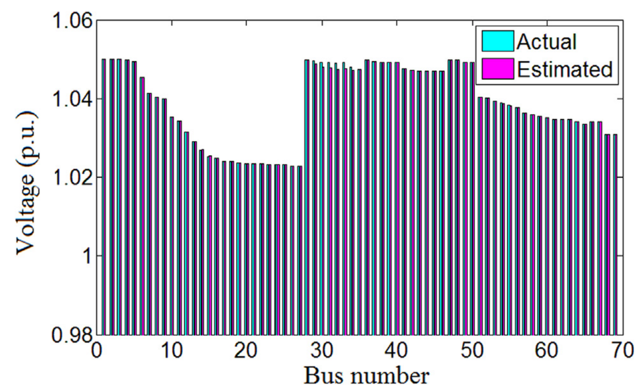

Fig. 14. Complete voltage profile, 69-bus feeder, test case #24.

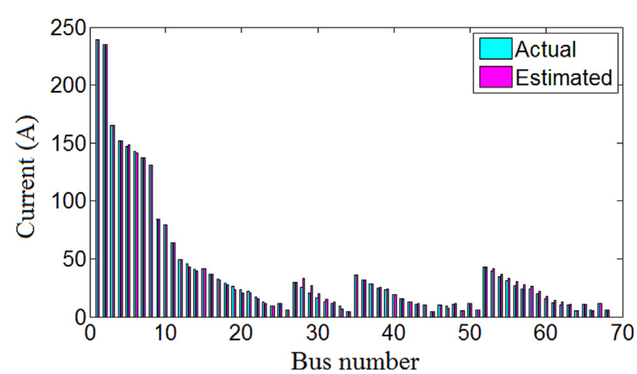

Fig. 15. Complete branch currents, 69-bus feeder, test case #24.

7.3. Results for the IEEE 34-Bus unbalanced feeder

The proposed three phase estimation algorithm is tested on the IEEE 34-bus feeder to prove its accuracy with unbalanced distribution feeders. The estimation scheme is done for laterals (30–33), (30–31), (24–28), (19–21), (19–23), (8–11), (16–17), and (3–4). After all laterals are evaluated, the algorithm analyzes the feeder stems (24–30), (16–19), (12–16), (3–8), and (0–3). For example, for the lateral (24–28); the SM connected to bus #24 first communicates its measurements to the CCU, which calculates the branch power and estimates voltages for the buses 24–28. The SM located at bus #28 then performs the same task, and the CCU estimates the lateral branch current and voltage profile from the perspective of SM located at bus #28. Then the CCU performs more accurate voltage profile estimation by deriving the weighted average of the two estimations. In the final step, the CCU utilizes the estimation algorithm explained in Section 4 to determine

Table 7
Summary of the IEEE 34-bus feeder test case results.

Test case #	Maximum voltage error for the three phases (p.u.)	Maximum load complex power error (%)	Average number of iterations required
25	0.000079	0.98	17
26	0.000163	3.7	19
27	0.00031	5.67	20
28	0.00045	6.83	19
29	0.00062	11.93	17
30	0.00087	9.68	21
31	0.00035	3.89	18
32	0.000638	6.59	18

the final estimation of the voltages, currents, and power losses of the lateral.

Eight test cases are carried out with different loading conditions and DGs locations and penetrations to prove the efficiency of the proposed scheme in accurate estimation of the voltage profile and loads powers. The unbalanced loads of each feeder are randomly selected in a certain range around an average loading condition (i.e. average load for each phase is 30.93 KW and 19.16 kVAr). Loads variations of 20% (i.e. average load of the feeder ± 10%), 50%, and 100% are considered in the test cases. In all test cases, the results obtained from the proposed method are compared to actual results obtained from load flow algorithm. Each test case is repeated, with random loading, for 10 times; the maximum load complex powers and maximum error in voltages of the three phases for all runs are calculated and presented in Table 7. It could be noticed from the results that the proposed three phase estimation technique has high accuracy in all test cases except cases with high load variations or high spot DGs penetration (e.g. test cases #29 and #30). However, as previously explained, very high DGs penetration is restricted due to technical operating constraints.

7.4. Comparison with published estimation methods

As explained in the introduction, in the literature, estimation methods are divided into two categories. The first are SE methods, which are dependent mainly on pseudo measurements and require information about historical load behavior. A valid comparison with the proposed method is therefore impossible since the proposed technique relies on only a few real-time measurements. It should be noted that if only a few measurements are available without measurement redundancy, traditional SE methods are unable to estimate system states due to lack of observability. The proposed method is thus inherently superior to SE methods in cases when few measurements are available. On the other hand, if the available data comprises redundant measurements, SE methods should be used rather than the proposed method because they can identify bad and missing data, a feature not offered by the proposed method. In order to achieve both advantages of the proposed technique and SE techniques, the proposed technique could be integrated with SE in order to enhance the system observability and to improve the technique ability to detect bad data. This integration, which is considered as a future work, could be achieved as the SMs are placed at every bus of the system; thus, redundant measurements are available. However, optimal section of SMs measurements to achieve the aforementioned tasks is mandatory.

The second category contains real-time estimation techniques. In test case #24, the proposed method was compared to the real-time estimation methods published in [12–14]. The results presented in Table 8 confirm the superiority of the proposed technique.

8. Potential applications

The accuracy of the estimations produced by the proposed technique makes it a suitable platform for many real-time applications, such as the following:

1) Voltage control applications: To limit voltage problems, these applications require continuous knowledge of system voltages in order to change the status of voltage control devices (voltage regulator, capacitors, etc.).
2) Power quality applications: The new method could be easily adapted for the detection of power quality problems.
3) DG connection impact assessment: The proposed method accurately estimates system changes following variations in DG power levels.
4) Demand side management: The developed method facilitates the online estimation of system loads.

9. Conclusions

This paper has presented a novel method for complete voltage, current, and power loss estimation. The proposed technique is dependent on the placement of SMs at specific locations determined based on distribution network topology. The SMs communicate their measurements to a CCU that uses the proposed algorithm for an accurate estimation of the complete network voltage profile, branch currents, and power losses. The proposed estimation scheme was implemented and tested using two feeders featuring laterals and different X/R ratios. The results were then compared to actual results obtained from load flow calculations. The comparison revealed the efficiency of the proposed scheme with respect to estimating the voltage profile, currents, and power losses for all test cases. The testing performed covered different levels of load variation and DG penetration.

The contributions of the proposed algorithm can be summarized as follows:

1) Any radial distribution network can be analyzed, regardless of length, topology, unbalanced nature, or impedance values.
2) SM locations are fixed regardless of the DG power and/or points of injection.
3) Compared to previous work in this field, a reduced number of measurements are required, and existing SMs are utilized, avoiding the need for new remote terminal units and thus decreasing the cost of measuring devices.
4) Because only real-time measurements are required, system observability is achieved without a need for billing data or historical load profiles.
5) Accurate estimations can be obtained for the complete voltage profile and not just maximum and minimum voltages.

Table 8
Comparison with the method published in [12], Test Case #24.

Item	Proposed technique	Methods in [12]
Number of measuring devices	14 (i.e., one at each branching and end bus)	18 (i.e., one at each DG bus and each end bus)
Type of measuring device	SM (lower cost)	RTU (Higher cost)
Ability to deal with laterals	Yes	No
Ability to deal with variable X/R ratios	Yes	No
Estimated variables	Complete voltage magnitudes and angles, feeder currents, load power, and power losses	Maximum and minimum voltage magnitudes only

6) The short computational time required for a complete estimation makes the method suitable for online applications.

The proposed method could function as a platform for numerous potential applications, especially in the presence of high levels of DG penetration.

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