Reconfigurable and flexible voltage control strategy using smart PV inverters with integrated energy storage for advanced distribution systems

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Abstract: A novel circuit topology is proposed for utility-owned photovoltaic (PV) inverters with integrated battery energy storage system (BESS) and compared to two state-of-the-art configurations. The proposed topology offers flexibility and can be applied to a range of distribution networks for tight voltage regulation. During BESS maintenance, the solar-storage system reconfigures itself for a self-run mode of operation, and actively compensates high penetration induced voltage fluctuation without activating overcurrent protection of the inverter, which is an added advantage of this strategy. This advantage is achieved by slightly increasing the inverter size to reserve a portion of inverter’s current-carrying capability. A dynamic model of the new configuration is also developed to analyse its performance in providing fast response for high ramp up/down solar irradiance variation. As the proposed control strategy is implemented at the device level, the local voltage regulation is quite guaranteed to be in the permissible range. Results from the analysis performed on a modified IEEE 33 bus medium voltage distribution network with multiple inverters show evidence that the proposed strategy has the potential to mitigate voltage fluctuation in several extreme cases.

1 Introduction

High penetration of solar photovoltaic (PV) energy in any feeder has the potential to change the voltage profile. Injection of active power from these distributed generations (DGs) may increase the voltage to unacceptable levels, especially at the end of the line (EOL) in a low voltage, weak radial distribution system [1]. For medium voltage (MV) and high-voltage distribution systems, it depends on the hosting capacity at different locations of the network [2]. On a cloudy day or during a peak load period, the voltage fluctuates and without proper control, the system could experience voltage instability. Furthermore, managing voltage fluctuations caused by rooftop single-phase PV inverters, which are mostly connected to low-voltage networks, requires significant investment and complex infrastructure. This issue has been reported as the main concern for utilities in the face of high penetration of PV power [3, 4]. Therefore, in contrast, utilities are now becoming more interested in investing in their own MV level PV generation connected to MV distribution networks [5].

Voltage regulation issue has been extensively studied in the literature. Volt-Var control [6–8] and active power curtailment [9–11] are thoroughly investigated. These methods often do not take the PV inverter dynamics into account. Also, utility-owned conventional assets for voltage regulation such as onload tap changers (OLTC), step voltage regulators (SVRs), and capacitor banks are shown to be properly coordinated with the newly installed smart PV inverters [1, 12, 13]. Battery energy storage system (BESS) has become an integral part of this architecture because of its various grid supporting features. BESS may be connected on the AC side or it could be integrated with the PV on the DC side, which is a less expensive solution [14]. A dedicated power conditioning system for the BESS operation is also not uncommon which adds more costs to the investment.

Today, a distributed network operator (DNO) is responsible for voltage regulation in their networks. Until now, PV inverters have been forced to operate at zero reactive power output. This has been modified in IEEE standard 1547a-2014 and now included in IEEE standard 1547a-2018. By this modification, IEEE aims at putting DGs to control the bus voltage. This is possible because the advanced capabilities of a smart inverter now include automatic voltage control. For proper coordination among different inverters, broadly two approaches have been proposed: (i) centralised and (ii) decentralised/distributed. The centralised approach offers wide area voltage control but requires a reliable communication scheme [15, 16]. A decentralised approach provides autonomy but suffers from limitation on voltage control range [17–19]. Multi-agent-based schemes have also been investigated in the literature which again requires reliable cyber communication protocols to transmit point-to-point messages among neighbours [20, 21]. Moreover, voltage control depends on R/X ratio at the point of common coupling (PCC). For different voltage levels, voltage control mechanisms are different [22]. This is shown in Table 1.

It is clear from Table 1 that voltage control by injecting or absorbing reactive power only applies to a high-voltage line, and, in some cases, to a MV line. Low-voltage and MV distribution networks require active power to correct a voltage issue, which is not considered in [6–8]. Moreover, PV panels connected to the far end of the distribution network create a weak grid, where voltage control depends mostly on local inverter control. OLTC and SVR respond slowly (within minutes) and sometimes require longer time due to communication latency. On the other hand, the nodes, which are closer to the substation end, create a stronger grid. In this case, voltage control of these nodes depends on the voltage

| Type of line | Voltage level, kV | Voltage control mechanism |
|-------------|------------------|--------------------------|
| low voltage | 7.7 <1           | active power (P)         |
| MV          | 0.85 1–34.5      | reactive power (Q) and/or active power (P) |
| high voltage| 34.5 and above   | reactive power (Q)       |

Table 1: Typical line parameters
sensitivity with respect to active and reactive power [23]. Voltage source converters (VSCs) are typically used as interface for solar PV systems for forward and reverse power flows in the feeder. The key to controlling the power flow is to control the dc-link voltage of these inverters as they operate only for a stable range of dc link voltages. Therefore, dc link voltage dynamics should be a key concern when injecting or absorbing active/reactive power which is often not considered in the existing solutions.

Considering all the above factors, this study first proposes a new topology for integrating BESS with the utility-owned PV. Secondly, a reconfigurable control strategy comparing the conventional and proposed two-stage solutions is outlined in detail. This strategy offers a wide voltage control range for weak or strong grid locations. Flexible voltage control is achieved by changing reactive power (Q) as a function of a sensitivity index (S) or active power (P) injection. This is decoupled in nature and can be done independently. In summary, the contribution of this study is in the introduction of a voltage control strategy in a reconfigurable and flexible manner based on the capacity of the PV inverter and BESS.

The paper is organised as follows. In Section 2, the proposed control strategies are discussed in detail. Section 3 focuses on the inverter's operational limit. Section 4 deals with dynamic modelling and compares different control configurations to facilitate the transition for re-configurability. Section 5 analyses the simulation results obtained from a modified IEEE-33 bus test system. Section 6 concludes the paper and provides future research directions.

2 Proposed control strategy

2.1 Background on the voltage control strategy

Most distribution systems are radial in nature. However, when a DG is connected, the system is no longer radial. A simple single line model of such a distribution system is shown in Fig. 1.

The upstream network with respect to the PCC is generally a bulk power system. Here, the transformer shown is an OLTC which regulates the voltage (±5%) at the feeder end with response time in minutes. The voltage at the PCC can be approximated as follows [24]:

\[ V_{\text{PCC}} \approx V_G + \frac{R P + X Q}{V_{\text{PCC}}} \]  \hspace{1cm} (1)

where \( V_G \) is the substation bus voltage, \( P = P_{\text{PCC}} - P_L \) and \( Q = Q_{\text{PCC}} - Q_L \), are the net active and reactive powers injected at the PCC, respectively, and \( R \) and \( X \) are the feeder resistance and reactance, respectively. To compensate for the voltage, rise/drop caused by \( P \), i.e. to make \( V_{\text{PCC}} \approx V_G \), the required \( Q \) is given by

\[ \frac{Q}{P} \approx \frac{-R}{X} \]  \hspace{1cm} (2)

Substituting the values from Table 1 in (2) shows that the \( Q \) demand is high for low-voltage distribution systems. For other voltage levels, this requirement is relatively low. The negative sign indicates that the net injection of active power (P) from the PV panels requires reactive power absorption to keep the PCC voltage at nominal value. Until now, a fixed power factor operation of the inverter is required by DNOs. This is equivalent to keeping the \( Q/P \) ratio constant. With the modification of IEEE 1547a-2018, this is going to be a challenge as DGs are now required to contribute towards correcting voltage issues by controlling both \( P \) and \( Q \).

However, as (2) shows, voltage support by only reactive power exchange greatly depends on the \( R/X \) ratio of that bus. Therefore, the reactive power control capability of the inverter must be considered. The \( Q \) reserve of an inverter depends on the maximum allowable current rating. The reserve can be shrunk or released based on the active power utilisation of the inverter. From (2), for a MV distribution system, the \( R/X \) ratio can be such that it may be able to compensate the voltage by only regulating \( Q \). In most of the cases, this is not true as heavy loading draws reactive power from the line.

Therefore, the second-best choice is to curtail \( P \) to control the voltage rise which needs an integrated storage solution to store the curtailed power. A BESS provides this support here. The alternative approach is to find a value for \( Q_{\text{PCC}} \) that minimises the voltage rise caused by \( P_{\text{PCC}} \). The PV injected current at the PCC can be calculated as follows:

\[ I_{\text{PCC}} = \left( \frac{P_{\text{PCC}} + jQ_{\text{PCC}}}{V_{\text{PCC}}} \right) = \left( \frac{P_{\text{PCC}} - jQ_{\text{PCC}}}{V_{\text{PCC}} \cos \delta - jV_{\text{PCC}} \sin \delta} \right) \]  \hspace{1cm} (3)

In (3), \( \delta \) is the angle between the voltage vector \( V_{\text{PCC}} \) and \( V_G \). Using the real and imaginary part of the calculated current and taking the voltage and impedance into consideration, a zero voltage drop equation can be derived as follows:

\[ V_G V_{\text{PCC}} \cos \delta = V_G^2 - R P_{\text{PCC}} - X Q_{\text{PCC}} \]  \hspace{1cm} (4)

\[ V_G V_{\text{PCC}} \sin \delta = R Q_{\text{PCC}} - X P_{\text{PCC}} \]  \hspace{1cm} (5)

Solving (4) and (5) to keep the voltage \( V_{\text{PCC}} \) at 1 p.u., the required \( Q \) is obtained by

\[ Q_{\text{PCC}} = \frac{X}{R + X} \left( \frac{X}{R + X} - I_{\text{PCC}}^* + 2 \frac{R P_{\text{PCC}}}{R + X} \right) \]  \hspace{1cm} (6)

If a load is connected to the generator bus as shown in Fig. 1, then setting the inverter reactive power reference, \( Q_{\text{RES}} \approx Q^*_{\text{PCC}} \) as per (6) guarantees a stable voltage profile. On the other hand, \( Q_{\text{RES}} \) can be set based on the inverter rating derived from the reserved \( Q \) as follows:

\[ Q_{\text{RES}} = \sqrt{S^* - P_{\text{RES}}} \]  \hspace{1cm} (7)

\[ Q_{\text{RES}} = P_{\text{PCC}} \tan \phi \]  \hspace{1cm} (8)

where \( S \) is the inverter rating and \( \phi \) is the power factor angle. Considering variable power factor control, (7) provides the total reserved \( Q \) capacity. If a fixed power factor control is desired, then (8) provides the \( Q \) reserve. In either case, \( Q_{\text{RES}} \) calculated from the above two equations may not be able to fulfil the requirement as calculated by (6), i.e. \( Q_{\text{RES}} \leq Q^*_{\text{PCC}} \). In a worst-case situation like this, active power curtailment is needed. In a conventional case without BESS, the OLTC/SVR changes its tap to correct any voltage issue. In this study, the assumption is that the inverter is the primary asset to fix the voltage and faster than OLTC in operation.

2.2 Voltage sensitivity calculation

From (1), the sensitivities of voltage at PCC with respect to the net injected active and reactive power are calculated by

\[ \frac{\partial V_{\text{PCC}}}{\partial P} = \frac{R}{V_{\text{PCC}}} \]  \hspace{1cm} (9)

\[ \frac{\partial V_{\text{PCC}}}{\partial Q} = \frac{X}{V_{\text{PCC}}} \]  \hspace{1cm} (10)

Dividing (9) by (10), \( S_i \) can be defined as

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Fig. 1 Single-line diagram of two generating stations
\[ S_I = \frac{\partial Q}{\partial P} = -\frac{R}{X} \]  
(11)

Partially differentiating (6) with respect to \( P_{\text{PCC}} \) leads to

\[ S_I = \left( \frac{1}{R_X} + \frac{X}{R} \right) - \frac{P_{\text{PCC}}}{Q_{\text{PCC}}} \left( \frac{X}{R} \right) \]  
(12)

At an initial operating point, PV does not inject any active or reactive power, i.e. \( P_{\text{PCC}} = 0 \) and \( Q_{\text{PCC}} = 0 \). So, (12) becomes (11), which is the easiest computation and usually sufficient for a wide range of loading conditions if static loading operation is assumed. For time-varying loads, the same \( S_I \) can be used as the impact of loading on sensitivity has been found to be very small in all cases studied to date [23].

### 2.3 Significance of the proposed voltage control strategy

The significance of the proposed voltage control strategy can be described using (2) and (7). For the voltage to be compensated locally, i.e. at the PCC, (2) estimates the amount of reactive power needed for that bus. This can be called as a ‘demand’ for voltage compensation of that bus. On the other hand, (7) is the reactive power reserve or ‘supply’ of a PV inverter whose active power can be controlled by a PV inverter and/or a BESS. Plotting (2) and (7) using the values from Table 1 leads to Fig. 2.

From Fig. 2, it is evident that for different line parameters, there is a maximum active power injection limit without disturbing the voltage profile. For example, the MV line would require absorbing around 1.5 MVAR to inject \(-4.5 \text{ MVAR},\) a 5 MVA inverter would be enough for this case. So, based on the voltage \( S_I \), a PV inverter would still inject active power without disturbing the voltage profile, if a certain amount of reactive power is exchanged. That reactive power reference is derived in (6) with the assumption that the pre-injection node voltage is 1 p.u. It can better be explained if (6) and (7) are plotted together as in Fig. 3. Notice that, now the reactive power demand given by (6); captures the actual network conditions for any voltage compensation needed. From Fig. 3, the reactive power needed to inject 3.5 MV A is 3.5 MVAR. Again, the inverter size is 5 MVA. However, the advantage is that it does not disturb the voltage profile even for different line parameter conditions as shown in Fig. 4.

### 2.4 Reconfigurable control strategy

For a two-stage power conversion, the VSC is typically followed by a dc/dc boost converter, which generates the duty cycle needed for the maximum power point tracker (MPPT). This is shown in Fig. 5a. This scheme injects or absorbs active current component according to the user defined dc link voltage reference \( I_{\text{DC}}^* \). In this way, the dc link voltage is preserved by using the inverter as a current controlled device. This mode will be referred to as configuration 1 throughout the paper. However, this configuration lacks the ability to directly control active power. As mentioned earlier, if the dc link voltage is within operational limits, active power \( P \) and reactive power \( Q \) can be controlled in a flexible manner. Therefore, to make configuration 1 more robust and achieve greater virtual inertia, the BESS is integrated with the dc link using a bi-directional dc/dc buck–boost converter as shown in Fig. 5b.

This opens a new dimension allowing one to use the PV source as a dispatchable generator. This is referred to as configuration 2. In this configuration, however, the control objectives of the boost and bi-directional buck–boost converter overlap. Moreover, this topology has several drawbacks. For instance, changing the load creates large transients in the dc link that might damage the BESS. It also requires a high-voltage compatible charge balancing circuit, which makes the control system more complicated. Moreover, it is difficult to ensure safety measures for the high-voltage level of BESS.

To design a dedicated controller for each specific task and avoid overlap in this dynamic environment, the BESS is proposed to be integrated with the PV output capacitor C1 as shown in Fig. 5c. This will be called configuration 3 henceforth. The proposed topology ensures low-voltage operation of the batteries with the scope of flexible design and proper safety. On top of that, it offers a reconfigurable control strategy with or without BESS that requires minimum modification in the controller design as discussed in Section 4. From MW-scale utility-owned PV standpoint, this is clearly an advantage for the battery management system. If the BESS needs overhauling and regular maintenance, the PV system can still be operated without any problem through automatic transitioning to configuration 1. The control objectives are listed in Table 2.

### 2.5 Flexible control strategy

The logic behind the reconfiguring decision can be implemented based on the BESS status. The transition from configuration 2/3 to
considering the life-span and functionality of the BESS. For this status becomes known, the algorithm takes the PV production and first attempts to regulate the reactive power (\(Q\)) as inputs and checks the voltage status. There is an utility. This range (\(SOC_{\text{min}}\)–\(SOC_{\text{max}}\) for configuration 2 or configuration 3, the BESS discharges. Confor...subject to (7) or (8) based on the utility practice.

To understand Fig. 6, a step-by-step configuration wise approach is required. In configuration 1, when \(V > V_{\text{upth}}\), when \(Q\) reserve is found to be not enough, the controller starts by disabling the MPPT operation, which is not desired for PV systems. In such a case, configuration 2 and configuration 3 are desirable as they can charge the BESS with the excess solar energy. When \(V < V_{\text{loth}}\), in case of configuration 2 or configuration 3, the BESS discharges. For configuration 1, this voltage condition means \(Q\) support has become limited. This is a regular case for PV without having a BESS and the inverter is essentially set to output maximum active power obtained by the MPPT algorithm used. However, the VAR control range can be broadened without activating the overcurrent protection, even while the inverter supplies maximum \(P\), by using a current reserved inverter as discussed in Section 3. In this study, \(P\) curtailment amount is calculated by multiplying the inverter's active power reference \((P_{\text{ref}})\) with the ratio of the nominal voltage to the measured voltage at the PCC. At the same time, \(Q\) control is used according to (6) in collaboration with \(P\) by calculating the sensitivity using (11) and (12). In other words, the proposed control strategy is decoupled in nature to compensate the voltage change based on the need for either active power \((P)\) or reactive power \((Q)\) or both. This is possible because the inverter can control \(P\) and \(Q\) independently up to the maximum current limit. Theoretically, an inverter can inject \(Q\) on a cycle-by-cycle basis. In practice, it has some time delay due to switching and communication latency. Therefore, voltage change is also not instantaneous, but this is still faster than OLTC operation.

### 3 Inverter operational limit

A conventional PV inverter capability curve is shown in Fig. 7a. There is a limit of reactive power that can be injected or absorbed at any time. This is denoted by \(+Q_{\text{max}}\) and \(-Q_{\text{max}}\). The maximum active power rating is \(P_{\text{max}}\) and \(\Omega\) is the power factor angle. If the dc link voltage is kept at an operational range, for low PV period or night time operation, \(Q\) capacity can be released and controlled within the rated current limit. It is important to mention here that the dc link capacitor requires active power to store charge in its electrostatic field. So, it is not possible to control the dc link voltage without BESS at night time or at any instant when the PV power is not enough. Similarly, for a user defined fixed leading/lagging power factor operation, the reactive power support suddenly vanishes when the PV panels produce the maximum active power \(P_{\text{max}}\) as shown in Fig. 7a. In other words, the maximum allowable current capacity is dedicated to active power. However, meeting the interconnection requirements as in IEEE 1547a-2018 is often not possible for this type of inverter.

An intelligent solution for better VAR support by using a slightly modified PV inverter is shown in Fig. 7b. Similar to the previous case, the limit of reactive power that can be injected or absorbed at a point of time is denoted by \(+Q_{\text{max}}\) and \(-Q_{\text{max}}\). However, this time, a portion of the current capacity is reserved for VAR support when the PV panels produce maximum power, \(P_{\text{max}}\). This is possible because the inverter is usually operated as a current controlled device. Of course, this increases the rating of the inverter, but the cost is worth it in the context of supporting VAR. For example, at 100% loading, an 1111 kVA inverter can supply 1000 kW and simultaneously 484 kVAR with a power factor of 0.9 lagging at the cost of current increase by only 11.1%. For the same power factor operation, a conventional 1000 kVA inverter provides 900 kW and 436 kVAR. This can be calculated from (7) and (8). To summarise, the overcurrent protection of the inverter does not get activated for another 11.1% margin of current increase compared to a typical 1000 kVA inverter. For partial loading, both the inverters provide the same support. Although most of the time, PV does not provide peak generation, however, the capacity installed should be maximised. The comparison of the VAR support capability of the two inverters (conventional versus current reserved) is shown in Fig. 8. Here, it is shown that the current-reserved PV inverter instantaneously provides maximum support \((Q_{\text{max}})\) when it

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Table 2: Control philosophy in two-stage PV inverter technology

| Converter | Configuration |
|-----------|---------------|
| boost MPPT | MPPT | \(V_{\text{dc}}\) control |
| bi-directional VSC | \(V_{\text{dc}}\) and Q | \(P\) and Q control |
| buck–boost control | MPPT | \(P\) and Q control |
Extended region of reactive power support is marked in Fig. 7 for all the configurations. Fig. 9 shows the detailed converter topologies used in configuration 3. The grid voltage and current are measured at the PCC. A phase locked loop tracks the voltage angle for MPPT operation. Measured three-phase voltages and currents are then converted to voltage and current dq quantities, respectively, using Clark’s and Park’s transformation. The d-axis component controls the active power and the q-axis component controls the reactive power. Using the instantaneous power theory, per unit active and reactive power can be computed as in (13) and (14)

\[ P_{\text{meas}} = V_d I_d + V_q I_q, \]  

\[ Q_{\text{meas}} = V_q I_d - V_d I_q. \]  

Here, \( V_d \) and \( I_d \) are the d-axis components of grid voltage and line current, respectively. Similarly, \( V_q \) and \( I_q \) are the q-axis components of the same.

### 4.1 Boost converter design

As flexibility is the primary focus, the front-end dc/dc boost converter has two different functions as discussed in Table 2. For the boost converter, the pulse-width modulation (PWM) pulses can be generated by a cascaded controller to trigger the switch S3. For configurations 1 and 2, the purpose of the boost converter is to track the MPPT voltage and control the current across inductor L1. This is done by the outer voltage and inner current loop controllers. Configuration 3 has the same controller except for the outer voltage control loop now fixes the voltage across C2. Eventually, the proportional–integral (PI) controllers (PI1, PI2) tuned for configurations 1 and 2 can effectively be used for configuration 3 as the inductor current dynamics does not vary too much for the same amount of power as shown in Fig. 9b.

### 4.2 Bi-directional buck–boost converter design

Configuration 1 does not have a bi-directional buck–boost converter as this is required only for BESS. Fig. 9c compares the controllers for the two configurations (without BESS and with BESS at inverter input). For the proposed configuration, MPPT is implemented in this converter. The input voltage is taken from capacitor C1. The same topology is applicable for configuration 2, which requires the input voltage to be taken from capacitor C2 as in Fig. 5b. However, in configuration 2, this converter is responsible for maintaining the dc-link voltage by charging or discharging the BESS from the inverter input. The goal is to generate the PWM signals for switches S1 and S2. Also, notice that the same references \( V_{\text{MPPT}} \) and \( V_{\text{DC}} \) have been used alternately as in Fig. 9b. This proves that the proposed control strategy will need minimum modification to switch from one state to another. This is beneficial because when BESS needs maintenance, the system can be operated in PV-only mode which is not difficult to achieve in configuration 2 due to its assigned control functions.

### 4.3 VSC controller design

VSC controllers and their PWM generation scheme are shown in Figs. 10a and b. Synchronous reference frame (SRF) transformation is used to decouple the voltage control. In SRF, the AC quantities are converted to DC and simple PI control can be used for compensation. In dq0-axis, the inverter voltage references can be generated using the following equation:

\[ \frac{V_d}{V_q} = \frac{R}{L} \frac{I_d}{I_q} + \frac{Q}{2 \pi f} \frac{V_d}{V_q} + \omega \left[ L \frac{V_d}{I_d} + \frac{V_q}{I_q} \right]. \]  

Here, the first two terms represent the filter dynamics, \( \omega \) is the decoupling term and the last term in (15) is the feed forward voltage from the grid. Fig. 10b shows the PWM pulse generation scheme for the proposed strategy using (15). Configuration 1 regulates the active power based on the dc link voltage reference \( (V_{\text{DC}}) \). It can indirectly control active power by changing the active current inverter processes; to maintain the dc link voltage following reference, set by the user.

Based on the availability, reactive power \( (Q) \) can be controlled directly and independently. In configurations 2 and 3, \( P \) and \( Q \) can directly be commanded to follow the reference \( (P_{\text{ref}} \) and \( Q_{\text{ref}} \)). To re-circuit these configurations, only one pre-tuned outer loop controller is required, namely, controller PI9 in configuration 2/3 which is different from PI5 in configuration 1 as shown in Fig. 10a.
5 Simulation results and analysis

The proposed control strategy has been tested in a modified IEEE 33 bus test system. It is a 12.66 kV MV network. The total load of the system is 3.7 + j2.3 MVA. Three PV generating stations, each rated at 1.11 MVA ($P_{\text{max}} = 1$ MW) are connected to three different buses 18, 22, and 33 as shown in Fig. 11. Please note all the sites do not have to install the solar-storage system to deploy the proposed strategy as discussed later in the section.

These buses are chosen as they are at the EOL and therefore challenge the proposed control strategy the most. Based on different optimisation goals, different locations for the PV and BESS can be chosen as discussed in [25], which is out of the scope of this study. There are also two OLTCs newly installed between buses 32 and 33, and buses 17 and 18. OLTC-1 is already installed at the substation. These are the locations that are located far enough from the substation. Actual solar irradiation data has been used from [26] to simulate different cases. It has been assumed that these inverters, in any voltage violation, respond first before the OLTC. Solar data is taken at every 1 min interval. All system parameters are listed in Table 3.

5.1 Case 1: low PV period with high variability

In a highly variable low PV period, buses 18 and 33 suffer from voltage drop without any reactive power support. This is shown in Fig. 12a.

Buses 18 and 33 both are at the far end of the network and have weak grid characteristics. This is a typical case for a weak grid condition if the bus is at the far end of the network. Voltage drop despite active power injection from the PV indicates that there is simply not enough reactive power flow in the feeder. Typically, utilities deploy capacitor banks to tackle this issue. Smart inverters can be controlled to work as a capacitive element to support the voltage. Fig. 12b shows the voltage regulation using $Q$ control from the inverter. Also, using an oversized inverter increases the $Q$ reserve, which provides additional support to mitigate voltage fluctuation. In this case, only regulating $Q$ is enough to do the job. No active power regulation is needed.

5.2 Case 2: high PV period with communication latency

In high-PV period, a communication latency of 100 ms inside the inverter control signal is considered. At bus 18, configuration 3 is installed. As expected, the injected power increases the voltage. Without activating the active power curtailment, first reactive power control is applied to fix the voltage. Interestingly, the voltage remains within the limit for most of the time until there is a drastic reduction in active power production due to passing clouds, as shown in Fig. 13a. At this point, due to a 100 ms communication latency, $Q_{\text{reg}}$ calculated by (6) is greater than $Q_{\text{RES}}$ of (7) which leads the voltage to go below $V_{\text{min}}$. This is a high rate ramp down situation which can be tackled by active power curtailment according to the proposed technique, which is shown in Fig. 13b. Curtailed power is used to charge the BESS and it solves the voltage issue even for a sudden change in PV production. The voltage remains within the specified limit of 0.95–1.05 p.u. during this event as indicated in Fig. 13b.

5.3 Case 3: effect of time varying loads

An aggregated time-varying load profile and a PV generation profile are shown in Fig. 14a. The voltage profile at bus 22 is shown in Fig. 14b. Regulating $Q$ according to (6) is found to be not enough to support voltage in case of high-peak load occurred in the evening. This can be attributed to the fact that bus 22 is closer to the substation and has a $S_0$ of 2 as calculated by (11). The inverter installed here has configuration 3. Therefore, the proposed flexible control strategy uses the $P$ regulation from the BESS. This is possible because it is assumed that BESS has enough SOC and therefore supported the evening peak load by injecting 800 kW as shown in Fig. 14c. As shown in Fig. 14b, there is no significant voltage violation observed in this case. In Section 2.2, it was discussed that the sensitivity change with respect to the loading
condition is small. This case provides evidence that the proposed flexible voltage control strategy can be applied to a wide range of load profiles, imposing varying $S_I$ on the system, throughout the day. However, without the support from the BESS, this voltage regulation becomes limited especially in the evening.

### 5.4 Case 4: transition from configuration 3 to configuration 1

Dynamic simulation for the proposed reconfigurable strategy at bus 18 is carried out. Fig. 15 shows a case of transition from configuration 3 to configuration 1. PV generation is kept constant at 1000 kW while an aggregated variable load profile is considered. Initially, there was no load. At $t = 1.5$ s, load increases suddenly which creates a transient surge current of 3.2 kA at the DC link. The load becomes 1.6 MW almost instantaneously. In practice, this high current is enough to damage the BESS if configuration 2 is considered. The proposed configuration 3, however, avoids this issue as the BESS is now connected to the input of the boost converter. PV generation is not enough to meet this demand. Therefore, the BESS takes care of the remaining 600 kW load. Assume that the initial SOC of the BESS was 50.032% and the lowest operational threshold is at 50%. At $t = 3$ s, the BESS hits this limit. So, the discharging current from the BESS becomes zero and the system reconfigures itself to configuration 1. This can be observed by a transient in the dc link voltage at $t = 3$ s. After that, the PV continues to inject 1000 kW whereas the grid takes care of the remaining load demand. This transition shows that the BESS can be in standby mode of operation when it crosses its SOC operation limit without interrupting the operation of the PV inverter to compensate the voltage variation. This means a degree of flexibility can be achieved for the system operator.

### 5.5 Case 5: OLTC tap changing operation

A comparison between the proposed control strategy with OLTC coordination and an OLTC-only case is carried out. The performance index to evaluate the result is taken to be the total number of tap changes occurred during a voltage violation. The OLTC parameters are shown in Table 4.

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**Table 3 System parameters for PV and BESS**

| PV panels | panel: $V_{oc} = 64.2$ V, $I_{sc} = 5.96$ A series/parallel modules = 15/219 |
|-----------|----------------------------------------------------------------------------------|
| each inverter | 1111 kVA, 3-phase, 60 Hz |
| BESS-configuration 2 | 800 V, 1250 Ah, Li-ion |
| BESS-configuration 3 | 500 V, 2000 Ah, Li-ion |
| $[kp1, ki1]$ | [0.05, 10] |
| $[kp2, ki2]$ | [0.025, 10] |
| $[kp3, ki3]$ | [0.4, 0.1] |
| $[kp4, ki4]$ | [0.1, 0.5] |
| $[kp5, ki5]$ | [7, 800] |
| $[kp6, ki6]$ | [0.3, 20] |
| $[kp7, ki7]$ | [0.01, 25] |
| $[kp8, ki8]$ | [0.3, 20] |
| $[kp9, ki9]$ | [0.1, 250] |
As shown in Table 5, the OLTC-only case suffered frequent voltage violations and a higher number of tap operations in all three cases compared to the proposed control strategy with OLTC coordination. In case 1, the simulation is carried out for the $Q$-control with PV–BESS–OLTC arrangement. Tap change count gets reduced eight-fold. A better result is shown for case 2 where the proposed strategy curtailed the active power to regulate the voltage profile. In a conventional case, it will require 29 tap changing operations to tackle the high-ramp up/down rate. As can be seen from the result of solar storage, no tap changing operation was required. The reason behind it is that the active power curtailment is comparatively a better strategy for voltage regulation; however, it comes with a cost of reduction in net PV energy yield. BESS gets charged to avoid this loss. This result also shows that the assumption made earlier inverter faster than OLTC operation (one minute for each step change) and thus, capable of correcting the voltage issue within a few seconds, is justified for this case. In case 3, the tap changing operation also reduces which justifies that the calculated $S_l$ in (12) for time varying loads works quite well as it does for static loading condition.

6 Conclusion

In this study, a reconfigurable solar-BESS topology is introduced and based on this, a flexible voltage control strategy is proposed. The key contributions of this study can be summarised as follows:

(i) First, a novel solar-storage configuration is introduced to incorporate a BESS, which is safe and easy to reconfigure from an operational standpoint. This proposed configuration 3 ensures the low-voltage operation of the BESS and thus creates a reconfigurable architecture, which can operate even under BESS maintenance. Using the proposed configuration, the voltage regulation range may be extended to low-voltage lines where active power is required.

(ii) A flexible voltage control strategy is proposed for the two-stage utility owned PV and integrated BESS technology. This feature allows the DNO to regulate the voltage in three different lines—low, medium, and high voltage. This strategy is shown to be a sensitivity-based approach utilising solar-BESS extensively.

Different test cases on a modified IEEE-33 bus test system provide evidence of voltage regulation in extreme weather variation. The coordination between existing voltage regulating devices and the inverter has also been investigated and compared with the proposed topology. It is evident that the solar-BESS can effectively reduce the tap operation and simulation results demonstrate the effectiveness of the proposed strategy to guarantee local voltage control.

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Table 4  OLTC parameter settings

| Parameters                  | OLTC                  |
|-----------------------------|-----------------------|
| reference voltage, p.u.     | 1.0                   |
| tap step width, p.u.        | 0.625                 |
| dead band, %                | 0.625                 |
| target nodes (OLTC-1, -2, -3) | 2, 33, 18             |
| time for each tap, s        | 60                    |

Table 5  Simulation results for tap changing operation

| Case no. | OLTC only | Proposed strategy with OLTC coordination |
|----------|-----------|-----------------------------------------|
|          | No. of tap changes | No. of tap changes |
| case 1   | 23         | 3                                      |
| case 2   | 29         | 0                                      |
| case 3   | 14         | 1                                      |
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