Autonomous adaptive Q(U) control for distributed generation in weak medium-voltage distribution grids

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Abstract
This study seeks to exploit the reactive power capability of inverter-based distributed generation (DG) to solve the voltageregulation challenges associated with weak medium-voltage distribution networks in developing countries. Voltage-dependent reactive power control, also known as the Q(U) control method, is widely used for voltage regulation. The challenge with this control mode, however, is determining its control parameters, which must be unique for each bus for optimal performance compared with implementing standardised or general parameters. This paper proposes an innovative approach to incorporate an adaptive functionality into the typical Q(U) control to enhance its performance in medium-voltage grids. This concept, when implemented, achieved better performance than that of the Q(U) control with fixed parameters, which was unsatisfactory under certain conditions, and performance comparable to that of the centralised voltage scheme, which relies on communication facilities.

1 | INTRODUCTION

Medium-voltage grids (MVGs) in some developing countries are saddled with voltage-regulation challenges mainly because of their design (longer distances) and insufficient reactive power provision, often characterised as weak grids. This challenge was emphasised in [1], and it intensifies during peak demand periods. The integration of distributed generation (DG) into MVGs presents an opportunity to mitigate this challenge, because distributed energy resources are integrated into the grid through smart power electronic interfaces. This equips DG with reactive power capabilities that are utilised to regulate the voltage at the point of common coupling (PCC), where DG is integrated. A typical example is in [2], where utilising the reactive power resources of DG based on different droop-control strategies minimised the number of voltage violations versus the base case where there was no reactive power from DG.

Subsequently, several voltage-control strategies have utilised reactive power from DG in medium- and low-voltage grids as well as micro grids. In [3], reactive power resources of DGs are used in a micro grid to enhance grid stability during small- and large-scale disturbances. The authors propose a hierarchical control structure: primary, secondary and tertiary. In this control, a radial basis function neural network is used to determine the reactive power reference for effective power sharing. In [4], a more decentralised hierarchical control in a micro grid with non-linear and sensitive loads is proposed. Of greatest interest here, however, are voltage-control strategies on MVGs with an emphasis on local DG voltage.

Local voltage-control strategies such as voltage-dependent reactive power control (Q(U)) and power factor-dependent active power control, termed cosφ(P), are proposed in various literature. Q(U) control is more efficient than other local control methods such as cosφ(P) [5, 6]. The main advantage of Q(U) is that the amount of reactive power compensation is solely dependent on the local voltage at the PCC, which depends on active and reactive power changes at the PCC and other nearby network elements. Thus, both the loading condition and DG active power output are considered in determining the reactive power output of the controller [5]. However, identifying the main parameters of this controller, namely, the deadband and gradient for the sloping region, is a
challenge. This depends on the network characteristics and the location of the DG. As such, implementing a general parameterisation or characterisation of these control parameters will not always provide good performance in terms of power losses and voltage regulation, since general parameterisation does not consider the uniqueness of voltage sensitivity of each bus.

To counter this challenge, several operational real-time and planning strategies have been implemented to tune the Q(U) parameters to achieve volt/var control. Real-time control strategies such as optimal power flow, model predictive control (MPC) etc. have been used. A voltage-control strategy based on multistep MPC was used to adjust the Q(U) characteristics to reduce the number of tap movements of the on-load tap changer (OLTC) and also reduce the number of voltage fluctuations in [7]. Also, an MPC-based control strategy was implemented in [8, 9], where the local Q(U) control parameters were tuned and adjusted to deal with voltage violations on the grid. In [10], the local Q(U) characteristic is adjusted and combined with a central controller to achieve coordinative voltage control. The coordination is based on a different timescale with the Q(U) control acting in seconds to provide a faster response, while the central control acts in tens of seconds. In [11, 12], the control strategy was instead based on optimal power flow. The authors of [11] used linearised power flow models and game theory to design the local controller Q(U) for voltage regulation on distribution networks. In [12], optimal power flow is used to coordinate the droop control of DG in dealing with overvoltage challenges on distribution grids. However, the implementation of schemes such as in [7–12] requires communication facilities that are absent in most medium-voltage distribution grids in developing countries because of limited financial resources.

The planning-based strategies are categorised into coordinated and decentralised schemes. Coordinated schemes use an offline central algorithm like optimization to tune the parameters of the local control, mostly to be implemented on a day-ahead dispatch. An offline optimal power flow method was used in [13] to tune and optimise the local controller for real-time operation for voltage-regulation purposes using only local measurements at the PCC. The controller was tuned with consideration to DG location and predicted conditions like the weather. Furthermore, the authors of [14] developed an offline methodology to determine the optimal settings for these local controllers. This was a quasi-dynamic methodology that considers historical load and solar variability conditions. The challenge with using predicted and historical values such as in [13, 14] are that, during implementation, errors may be encountered which will affect the efficient implementation of the controller. The authors of [15] used a centralised algorithm based on system optimization to tune Q(U) and cosφ(P) of DG inverters. In the central algorithm, the local curves were formulated mathematically using piecewise linearisation to determine local curve characteristics on a day-ahead schedule, and thus the curves were changed daily. To overcome complexity in implementing the central scheme in [15], the authors of [16] proposed a strategy based on the kriging metamodel to minimise the calculation involved in the optimization process. But the uncertainty associated with renewable DG and load, and errors in forecasting their values, sometimes make day-ahead scheduling as proposed in [15, 16] ineffective in voltage regulation. Thus, it is desirable to have an adaptive scheme.

In contrast, decentralised schemes use local measurement (available at the PCC) to adjust the local characteristic curve of the controller as seen in [17]. Reference [17] implemented a local adaptive scheme based on a fuzzy inference method. The active power output of DG and voltage at the PCC are input to the fuzzy set of rules to generate a single output signal that is used to adapt the Q(U) to the prevailing grid condition. A similar work was done in [18], where the fuzzy inference method was replaced with a droop function. This work in [17] did not consider the uniqueness of the voltage sensitivity of each bus. The adaptive control developed in [19] ensured that not only is the voltage at the PCC kept within the regulatory limits but also the stability of the voltage is considered. This control utilised computed line impedances between the bus of interest and slack bus. In practice, line impedance is affected by atmospheric conditions, and hence its computations are always associated with errors.

This paper provides a new method to solve the voltageregulation problem in weak MVGs by proposing an adaptive autonomous Q(U) control that adapts to changing grid conditions by incorporating an adaptive functionality. This functionality supports the Q(U) in providing reactive power compensation. The local adaptive Q(U) control provides these functions:

- It considers the uniqueness of the voltage sensitivity of each bus in the MVG.
- It utilises the full reactive power capability of the inverter, even when there is no or low active power from the DG.

The adaptive functionality seeks to compensate for the additional requirement of reactive power needed to regulate and stabilise the voltage at the PCC when typical Q(U) control performance is not satisfactory. This is performed primarily in two stages. The first is using a voltage-sensitivity fitting function to generate the desired reactive power. This function is obtained using a surface fitting technique to derive a function between the voltage at the PCC and the active and reactive power from DG. The second stage involves the adaptive functionality performing a voltage stability assessment using a local bus voltage stability index that is dependent on local voltage measurements at the PCC. The main contributions of this paper are as follows:

- Incorporated an adaptive functionality into the standard fixed Q(U) control that automatically changes the amount of reactive power compensation with the changing grid conditions such changes in load and DG output. This resulted in the full utilization of reactive power resources of DG.
- This control operates with only locally measured variables at the PCC without the need for communication facilities. Thus, it is easily implementable in MVGs that lack such facilities.
- Incorporated a voltage stability block into the Q(U) control that ensured that the amount of reactive power compensation from the DG enhances the voltage stability of the bus and the grid.

This paper is organised as follows: A detailed explanation of the approach used is explained in the methodology (Section 2). This is followed by the test cases and scenarios used to validate
this control in Section 3. The discussions of the results and conclusions are presented in Sections 4 and 5, respectively.

2 | METHODOLOGY

2.1 | Typical Q(U) control

The typical Q(U) injects or absorbs reactive power based on the voltage at the point where the inverter is integrated. Mathematically, it uses a piecewise linear curve to describe the relation between the voltage at the integration point and reactive power supply from the DG. The droop curve of this controller is shown in Figure 1.

Based on this curve, the reactive power (Q) for any voltage is calculated using (1), where Q_max is the maximum reactive power that the DG can inject or absorb. The interval between U_2 and U_3 acts as a deadband, and thus no reactive power is supplied when the voltage at the integration point is between these values. Reactive power is absorbed when the voltage exceeds U_3 for the inductive operation, whereas it injects reactive power when the voltage is below U_2. The amount of reactive power absorption and injection is determined by the droop:

\[
Q(U) = \begin{cases} 
  Q_{\text{max}}, & U < U_1 \\
  \frac{Q_{\text{max}}}{U_1 - U_2}(U - U_1) + Q_{\text{max}}, & U_1 \leq U \leq U_2 \\
  0, & U_2 < U \leq U_3 \\
  \frac{Q_{\text{max}}}{U_3 - U_4}(U + U_3), & U_3 < U \leq U_4 \\
  -Q_{\text{max}}, & U > U_4 
\end{cases}
\]  

\[ (1) \]

2.2 | Voltage sensitivity function by surface fitting technique

From Figure 2, the magnitude of change in the voltage at bus 2 is dependent on the sensitivity of the bus to active and reactive power injected at the bus. This is expressed mathematically in (2):

\[
\Delta V_{PCC} = \frac{\partial V_{PCC}}{\partial P_{DG}} \Delta P_{DG} + \frac{\partial V_{PCC}}{\partial Q_{DG}} \Delta Q_{DG}  
\]

where \( V_{PCC} \) is the voltage at bus 2, which is the PCC; \( P_{DG} \) and \( Q_{DG} \) are the active and reactive power injections, respectively, from the DG into the grid; \( \partial V_{PCC}/\partial P_{DG} \) and \( \partial V_{PCC}/\partial Q_{DG} \) are the voltage sensitivity coefficients for active and reactive power, respectively. These coefficients determine how sensitive the voltage is to power injections at the bus. Methods such as finding the inverse of the Jacobian matrix extracted from load flow calculations and the perturb and observe approach that is also based on power flow calculations are used in various works to calculate these sensitivities. However, the setback of these approaches is that running the power flow during network operation requires remote access to the entire network. Thus, to overcome the challenge of remote monitoring, a fitting-function-based sensitivity approach was proposed and validated in [20]. The authors compared this method with the Jacobian matrix and obtained similar results and hence used it in this work. This method is based on using different combinations of demand and generation offline power flow to generate a non-linear function. Based on the results obtained for voltages at the bus of interest, the surface fitting technique [21] is used to develop a linear function—that is, \( V_{PCC} \) as a function of \( P_{DG} \) and \( Q_{DG} \), expressed in (3):

\[
V_{PCC} = f(P_{DG}, Q_{DG}) 
\]

The sensitivity values are then calculated by finding the partial derivatives expressed in (4) and (5). They are utilised for all possible load and generation changes in the network:

\[
\frac{\partial V_{PCC}}{\partial P_{DG}} = \frac{\partial f(P_{DG}, Q_{DG})}{\partial P_{DG}} 
\]  

\[ (4) \]
\[
\frac{\partial V_{PCC}}{\partial Q_{DG}} = \frac{\partial f(P_{DG}, Q_{DG})}{\partial Q_{DG}} \quad (5)
\]

The fitting function approach implemented in this work is based on random values for demand and generation to incorporate the variability of load and DG profiles. The scope of this work is limited to the reactive power of DG for voltage control, and thus calculation of the voltage sensitivity coefficient with respect to reactive power expressed in (5) is of interest in this work. Also, this work does not consider active power curtailment, and hence priority is always given to active power. Lastly, DG is assumed to be provided by a photovoltaic (PV) generator.

To determine the surface fitting function, the following steps are followed:

- For demand and generation, 50 different levels are created. Thus, load demand varies from 0% to 100% of peak value in steps of 0.0067 p.u. This is repeated for the PV peak active power output, resulting in 150 x 150 combinations.
- To consider reactive power from the DG, different power factor values ranging from 0.95 to 1.00 in steps of 0.01 are considered. Thus, there will be 135,000 (150 x 150 x 6) combinations.
- Load flow analysis is carried out for 135,000 combinations of load (demand) and DG output for active and reactive power.
- Based on the results obtained, the surface fitting technique will be used to generate a non-linear polynomial function in the form of (6) for each bus of interest, where \( Z_x \) are the constant coefficients that are determined using the curve fitting toolbox in Matlab [22]. This toolbox uses numerical optimization algorithms to calculate coefficients. Subsequently, the voltage sensitivity coefficient with respect to reactive power is calculated in accordance with (5):

\[
V_{CP}(P_{DG}, Q_{DG}) = \sum_{x=0}^{3} \sum_{y=0}^{3} Z_x \cdot P_{DG}^x \cdot Q_{DG}^y \quad (6)
\]

2.3 | Local voltage stability index

Estimation of the stability of local bus voltages using local measurements is of interest in distribution networks with limited communication facilities. As such, the idea of estimating the Thevenin equivalent at a node of interest (local bus) in power networks is quite significant. This is because the Thevenin equivalent represents the system’s operational conditions (line impedances, active and reactive load demand etc.) seen from the node of interest, and hence it can be used to determine voltage stability through a voltage stability index (VSI) [23]. Subsequently, it has been adopted in this work. The VSI was developed using Tellegen’s theorem and adjoint networks. It was based on the principle of circuit theory, which states that the system reaches maximum transferable power when the load impedance becomes equal to the Thevenin impedance, beyond which the system becomes unstable. The index as defined in (7, 8):

\[
VSI = \left| \frac{Z_L - Z_{TH}}{Z_L} \right| \quad (7)
\]

\[
Z_L = \left| \frac{\Delta V}{\Delta I} \right| ; \quad Z_{TH} = \left| \frac{\Delta V}{\Delta I} \right| \quad (8)
\]

where \( Z_{TH} \) is the complex Thevenin impedance, \( Z_L \) is the complex load impedance, \( \Delta V \) is the complex voltage at a bus, \( \Delta I \) is the complex current at a bus, \( \Delta I \) is the change in two successive complex current measurements, and \( \Delta V \) is the change in voltage for two successive complex voltage measurements.

This makes it possible to estimate VSI locally, because it depends only on currents and voltages, which can be determined locally at the bus of interest. Index values range from 0 to 1, with 1 for normal condition and 0 representing the voltage collapse point. The Thevenin impedance can only be determined when there are changes in the current and voltage, thus, making the index more sensitive to changes in current and voltage. The challenge with this index is to determine the minimum threshold \( (I_{min}) \) for the change in current \( (\Delta I) \). For this study, the minimum threshold value for change in current is 0.015 p.u.; this is based on the previous work done in [23]. Thus, the Thevenin impedance is only calculated if the current is above this threshold; otherwise it is zero.

2.4 | Adaptive functionality

The adaptive functionality as proposed in this paper is explained in Figure 3. This functionality has two main blocks, namely a sensitivity-fitting function and voltage-stability blocks. The theoretical framework for these blocks was explained in Sections 2.2 and 2.3.

The adaptive functionality only works when the voltage at the PCC is not within the specified deadband (0.97 to 1.03 p.u.) of the Q(U) control. Otherwise, \( Q_{SF} \) which is the amount of reactive power determined by the voltage sensitivity function, is determined based on DG active power, reactive power and voltage at the PCC \( (V_{PCC}) \). Because the reactive power of DG is limited by the capacity of the inverter in MVA, a limiting factor, \( S_{lim} \), which is the rating of the inverter, is added to the voltage sensitivity block. Priority is given to active power, and the inverter is oversized by 1.1 times the peak active power of the DG, thus making room for reactive power during peak generation from the DG if \( Q_{SF} \) determined by the fitting function is more than the maximum allowable reactive power \( (Q_{limf}) \). This is the maximum amount of reactive power compensation from the DG at a time; it is dependent on the current operating active power of the DG and the \( S_{lim} \), and
then the generated $Q_{SF}$ will equal $Q_{max}$. The $Q_{SF}$ is determined from (9) as follows:

$$Q_{SF} = \frac{V_{\text{target}} - V_{\text{PCC}}}{\partial V_{\text{PCC}} / \partial Q_{DG}}$$

(9)

where $V_{\text{target}}$ is the target voltage, which is the desired or expected voltage at the bus after the injection or absorption of $Q_{SF}$. Its value is carefully chosen to keep the voltages closed to the limit of the dead band of the Q(U) control. However, it can be set to any desired value within the grid code limit that the system operator desires. Herein, it is set to 0.965 and 1.035 p.u. for the capacitive and inductive mode, respectively.

The voltage stability block ensures that $Q_{SF}$ determined by the sensitivity function will not destabilise the voltage at the PCC. It does this by calculating the VSI using (7). The consecutive measurement samples used in the calculation of the index in this work is before and after the addition of reactive power from the DG. To calculate $Z_{TH}$, $\Delta V_r$ and $\Delta I_r$ are calculated from (10) and (11):

$$\Delta V_r = |V_{\text{target}} - V_{\text{PCC}}|$$

(10)

$$\Delta I_r = |S_{\text{after} Q / V_{\text{target}}} - (S_{\text{before} Q / V_{\text{PCC}}})|$$

(11)

where $S_{\text{after} Q}$ and $S_{\text{before} Q}$ are the effective load in MVA after and before, respectively, the addition of reactive power from DG, because DG is modelled as a negative load. Because the index is more sensitive to changes in voltage and current, the minimum threshold for $\Delta I_r$ for calculating this index is set to 0.015 p.u. If $\Delta I_r$ is below this threshold, then $Z_{TH}$ is set to zero. The minimum VSI index value is set to 0.2. This can be set to a higher value based on the preference of the system operator if the latter wants to ensure more stability. If the calculated VSI is less than 0.2, then $V_{\text{target}}$ is adjusted by either increasing or decreasing it by 0.002 p.u. for the inductive or capacitive mode, respectively. Because the fitting function utilises the full capacity of the inverter in controlling the voltage, the reactive power injected or absorbed ($Q_{new}$) equals $Q_{SF}$ if the absolute $Q_{SF}$ is more than the absolute of $Q$ (the amount of reactive power determined by the standard Q(U) control).

### 2.5 Centralised voltage control scheme

To validate the performance of the proposed Q(U) control with adaptive functionality, it is compared with a centralised voltage control (CVC) scheme. The CVC scheme is an active scheme that relies on communication facilities to determine the optimal reactive power setting of each inverter to maximise the VSI of the network. Thus, this CVC scheme is an optimization algorithm with the reactive power settings of each inverter as the decision variables. They are programmed as continuous variables. The maximum amount of reactive power injected or absorbed is determined by the size of the inverter in MVA. The size of the inverter (MVA) is set as 1.1 times peak MW capacity, based on work done by the authors of [24] to determine the optimal inverter size for efficient utilization of reactive power resources. Thus, at peak MW power, the maximum reactive power injected or absorbed is 0.45 p.u. The optimization tool for this algorithm is the genetic algorithm (GA). The GA is an evolutionary technique based on the principle of natural selection.

![Flowchart for Q(U) with adaptive functionality](image)
The objective function of this active scheme is to maximise VSI as shown in (7). Both equality and inequality constraints are expressed in (12–16) as follows:

\[ P_{Gi} - P_{Di} = \sum_{j=1}^{N} |V_j| \left( |G_{ij}| \cos(\delta) + |B_{ij}| \sin(\delta) \right) = 0 \]  

\[ Q_{Gi} - Q_{Di} = \sum_{j=1}^{N} |V_j| \left( |G_{ij}| \sin(\delta) - |B_{ij}| \cos(\delta) \right) = 0 \]  

\[ \delta = \delta_i - \delta_j \]  

\[ V_i^{\min} \leq V_i \leq V_i^{\max} \]  

\[ S_l \leq S_l^{\max} \]

where \( P_{Gi} \) is the active power generated at bus \( i \), \( P_{Di} \) is the active power load at bus \( i \), \( Q_{Gi} \) is the reactive power generated at bus \( i \), \( Q_{Di} \) is the reactive power load at bus \( i \), \( G_{ij} \) and \( B_{ij} \) are the real and imaginary parts of the complex admittance between buses \( i \) and \( j \), respectively, and \( \delta \) is the voltage angle between buses \( i \) and \( j \). \( V_j \) is the complex voltage at bus \( i \), \( S_l \) is the complex apparent power flowing through a transmission line. The voltage limit for each bus is \pm 5\%.

The flowchart shown in Figure 4 is used to explain this CVC scheme. This is implemented in Matlab using the GA toolbox. The optimization parameters are shown in Table 1.

**Figure 4** Centralised voltage-control flowchart

| Table 1 | Parameters for genetic algorithm |
|---------|---------------------------------|
| GA Parameter | Value |
| Number of generations | 100 |
| Population size | 50 |
| Crossover function (rate) | 0.8 |
| Stall generations limit | 70 |
| Tolerance | \( 1 \times 10^{-6} \) |

The test network used in this work is the 16-bus generic medium-voltage system as shown in Figure 5. This is adopted to represent a typical Ghanaian distribution network. The total load on the system is 38.94 MVA. It has two OLTC connected between buses 1 and 2 and a voltage regulator (VR) between buses 8 and 9. The VR is an autotransformer equipped with a tap changer. The taps setting of the VR and OLTC are set to 0.97 and 0.92 p.u., respectively. This is to create low voltages at the ends of the feeder during peak demand period, which is typical of weak medium-voltage networks. Other parameters such as the base loads, transmission line parameters and maximum allowable complex power \( S_l^{\max} \) flowing through each transmission line are obtained from test system data [25]. Even though, most medium-voltage networks are equipped voltage-control devices such as OLTC and VR, the interactions between DG and these devices are not considered in this work. This is because even if they are considered, they will be operated in different time scales as implemented in works such as [26–28], because DGs have a faster response because of its power electronic interface as compared to mechanically switched OLTC or capacitor banks.

### 3 | TEST CASE

#### 3.1 | Test network

The test network used in this work is the 16-bus generic medium-voltage system as shown in Figure 5. This is adopted to represent a typical Ghanaian distribution network. The total load on the system is 38.94 MVA. It has two OLTC connected between buses 1 and 2 and a voltage regulator (VR) between buses 8 and 9. The VR is an autotransformer equipped with a tap changer. The taps setting of the VR and OLTC are set to 0.97 and 0.92 p.u., respectively. This is to create low voltages at the ends of the feeder during peak demand period, which is typical of weak medium-voltage networks. Other parameters such as the base loads, transmission line parameters and maximum allowable complex power \( S_l^{\max} \) flowing through each transmission line are obtained from test system data [25]. Even though, most medium-voltage networks are equipped voltage-control devices such as OLTC and VR, the interactions between DG and these devices are not considered in this work. This is because even if they are considered, they will be operated in different time scales as implemented in works such as [26–28], because DGs have a faster response because of its power electronic interface as compared to mechanically switched OLTC or capacitor banks.

#### 3.2 | Test scenarios

To validate the performance of the proposed scheme, two test scenarios are simulated and analysed:

- Scenario 1: This consists of a single DG with peak megawatt capacity of 8 MW. Thus, the inverter is 8.8 MVA as explained in Section 2.5. This is connected at the tail end of
the feeder (bus 11) and is used to validate the efficiency of the proposed concept in mitigating the voltage-regulation problem in weak MVGs by comparing it with the Q(U) control with fixed parameters and when there is no DG on the grid.

- **Scenario 2**: The second scenario involves the connection of multiple DGs. In this scenario, five DGs are connected to buses, 7, 10, 11, 13 and 16. Buses 7, 10 and 11 represent the tail ends of the feeder associated with low-voltage situations during peak load, and buses 13 and 16 characterise locations that have low demand, such as rural areas, and hence have high voltages. Each DG is rated at 5.5 MVA with a peak active power capacity of 5 MW. The DGs operating with Q(U) control with adaptive functionality will be compared with the Q(U) control with fixed parameters and an active CVC scheme. Because CVC requires two consecutive measurements to calculate the objective function, the simulation starts from the second hour on the first day.
- **Scenario 3**: This scenario is similar to scenario 2 with the same DG location and fitting function. The only difference in this scenario is that the operating conditions of grid are changed to demonstrate the effectiveness of the scheme in dealing with disturbances such as changes in load, DG and line impedances. Two main subscenarios are created: (a) There is a simultaneous increase in both DG and load output by 10%. (b) The line impedances are increased by 10% of the base value.

The values for $U_1$, $U_2$, $U_3$, $U_4$ for the Q(U) control as described in Figure 1 and in (1) for both scenarios are respectively set to 0.93, 0.97, 1.03 and 1.07 (all p.u.) based on an earlier work done by the authors of [29]. The displacement

**FIGURE 5** 16-Bus medium-voltage distribution network

**FIGURE 6** Typical Ghanaian demand and photovoltaic active power profile
factor was limited to $\cos \phi = 0.95$ for each inverter. Each scenario is examined against a time series simulation of 1 week with hourly resolution. Hourly load profiles for 25–31 Aug 2016 obtained from Ghana Grid company is used and PV active power output based on solar irradiance data from [30] for the same period is used for the simulation. This is shown in Figure 6.

To compute the load at any hour, the base load obtained from the test system described in Section 3.1 is multiplied by the per-unit value of demand profile shown in Figure 6 for that same hour. Similarly, for DG output active power, the peak active power is multiplied by the PV curve (Figure 6) for that particular hour. These curves provide the worst-case test scenario because the peak PV period coincides with load periods and vice versa. Also, for each scenario, the sensitivity function is developed for each bus using the steps described in Section 2.2. The voltage values for these scenarios are compared against the Ghana grid code voltage limit of ±5% [31].

The curve-fitting toolbox in Matlab is used to generate the sensitivity function [22]. GA toolbox also in Matlab is used for the optimization. The power flow simulations are implemented in MATLAB/Matpower software [32].

4 | SIMULATION RESULTS

4.1 | Scenario 1—single distributed generation scenario

The results ($V_{CP}$, $P_{DG}$, $Q_{DG}$) from the different combinations (150 x 150 x 6) of load flow are used to develop a three-dimensional surface as shown in Figure 7. The surface has six black lines representing the six selected power factors. Based on this surface, a non-linear polynomial non-linear function as expressed in (17) is generated using surface fitting technique.

$$V_{CP} = z_0 + z_1Q_{DG} + z_2P_{DG} + z_3Q_{DG}^2 + z_4P_{DG}Q_{DG}$$

(17)

The value of the parameters of this function are shown in Table 2.

| Bus no. | $z_0$ | $z_1$ | $z_2$ | $z_3$ | $z_4$ |
|---------|-------|-------|-------|-------|-------|
| 11      | 1.028 | 0.01647 | 0.02422 | 0.000522 | 0.002765 |

Henceforth in this paper, the $Q(U)$ control with fixed parameters is denoted as $Q(U)_{fix}$, $Q(U)$ control with adaptive functionality is denoted as $Q(U)_{adapt}$ and the centralised control is denoted as CVC. These notations are used in explaining the results.

For easy comparison, the results for only the first day are shown here. The reactive power injected or absorbed by the inverter and voltage profile at bus 11 is shown in Figure 8a,b, respectively. When there was no DG (PV) the bus experienced low voltages (below the lower limit of 0.95 p.u.) during the peak demand (19th to 21st hour). For the $Q(U)_{fix}$ control, it was able to regulate the voltage well except during the peak solar hours (11th to 14th hour) where the voltage exceeded the regulatory limit of 1.05 p.u. This was because the reactive power absorbed by the DG was not sufficient to reduce the voltage rise at the bus. However, $Q(U)_{adapt}$ was able to regulate the voltage within the regulatory range of 0.95 to 1.05 p.u. during the entire period including peak demand and solar hour period. This was because it utilised the full reactive power capability of the inverter and also considered the voltage sensitivity coefficient with respect to reactive power of bus 11.

4.2 | Scenario 2—multiple distributed generation scenarios

The values for the sensitivity-fitting function similar to (17) are shown in Table 3 for buses 11, 10, 13, 16 and 7 where the DGs are integrated.

The results for voltages and reactive power compensation for the entire 1-week period for the five DG buses operating with the proposed scheme are shown in Figures 9 and 10. In Figure 9, there was a general voltage rise during the peak solar hours of the PV (from hour 11 to hour 14 each day). But the
**Table 3** Parameters for multiple distribution scenarios

| Bus No. | Parameters for fitting function |
|---------|---------------------------------|
|         | $z_0$ | $z_1$ | $z_2$ | $z_3$ | $z_4$ |
| 11      | 1.028 | 0.03766 | 0.03928 | 0.002271 | 0.006284 |
| 10      | 1.044 | 0.03628 | 0.02869 | 0.002207 | 0.004062 |
| 13      | 1.025 | 0.01237 | 0.003264 | 0.00053 | −0.0002774 |
| 16      | 1.025 | 0.01606 | 0.008906 | 0.000553 | 8.62E-06 |
| 7       | 0.9859 | 0.0208 | 0.0133 | 0.00096 | 0.0006683 |

$Q(\text{U})_{\text{adap}}$ control was able to regulate the voltage within the acceptable grid code ranges of 0.95 to 1.05 p.u. for all DG-connected buses at all times. This was achieved by absorbing sufficient reactive power to mitigate the voltage rise phenomenon as shown in Figure 10 during this period.

Also, during peak demand period (from the 17th to 20th hour each day), the DGs operating with $Q(\text{U})_{\text{adap}}$ at buses 11, 10, 13, 16 and 7 injected the needed reactive power to keep the voltage within the regulatory limit.

Figure 11a–d shows comparative voltage results of the proposed $Q(\text{U})_{\text{adap}}$ with the $Q(\text{U})_{\text{fix}}$ and active CVC scheme for only the first day of the week. It can be seen $Q(\text{U})_{\text{fix}}$ could not regulate the voltage at buses 11 and 10 to the acceptable grid code range, during the peak solar hours (11th to 13th hour). From Figure 11b, the voltage at bus 10 was 1.062, 1.053 and 1.064 p.u. at hours 11, 12 and 13, respectively, while for bus 11 in Figure 11a, it was respectively 1.072, 1.059 and 1.076 p.u. for the same period. This is more than the maximum grid code limit of 1.05 p.u., signifying that the generalized parameterisation of the $Q(\text{U})$ control will not always elicit good performance. Although from Figure 12a,b for DGs at buses 11 and 10, respectively, reactive power was absorbed during the peak solar hours, it was not enough to regulate the voltage. The reason being that, fixed parameterisation does not consider the uniqueness of each bus, as such it works only in some circumstances as seen in Figures 11c,d for buses 16 and 7, respectively. The $Q(\text{U})_{\text{adap}}$ achieved a comparable performance with the CVC scheme as it was able to regulate the voltage under all circumstances for DG connected buses as shown in Figure 11a–d. Throughout the 24-h period, the voltage was within the grid code limit (0.95 to 1.05 p.u.). This is commendable because the CVC relies on communication facilities to operate and the former does not, making it a cheaper option to implement.

Table 4 provides an overall grid performance of the entire grid for buses with and without DGs. The CVC showed a superior performance in terms of voltage regulation because the maximum and minimum voltage were within the grid code limit of ±5%. This is because it has an overall view of the grid as compared to the $Q(\text{U})_{\text{adap}}$ and $Q(\text{U})_{\text{fix}}$ controls which acts only locally. On the other hand, this resulted in the DGs supplying a total net reactive power of 595.91 MVAR, thereby worsening the VSI because of the large amount of reactive power. However $Q(\text{U})_{\text{adap}}$ control achieved better results as compared to the $Q(\text{U})_{\text{fix}}$ control. For example, $Q(\text{U})_{\text{adap}}$ had a total of 29 violations at buses where there was no DG integrated as compared to 37 violations of the fixed $Q(\text{U})$ control and also an improved overall VSI of 0.936.

4.3 | Scenario 3

The results for scenario 3 are shown in Figures 13 and 14 for the subscenario where there was a simultaneous increase in both load and DG output by 10% and Figures 15 and 16...
**FIGURE 10** Results for reactive power compensation by inverters for the period at buses 11, 10, 13, 16 and 7

**FIGURE 11** Results for voltage profile for $Q(U)_{\text{adap}}$, $Q(U)_{\text{fix}}$ and centralised voltage control (CVC) at buses (a) 11, (b) 10, (c) 16 and (d) 7
showing results when the line impedances are increased by also 10%. From these results, the scheme efficiently regulated the voltage at the DG connected buses within the acceptable grid code limit during both the peak DG and load period. It can be inferred that this scheme will be able to deal with changes in line impedance values as it is dependent on temperature and atmospheric condition which keeps changing with time. Also, works effectively with changes in load and DG.

### DISCUSSION

The idea of this paper is to propose an adaptive autonomous Q(U) control scheme for weak medium-voltage distribution grids with voltage regulating challenges. This control operates without communication facilities, eliminating the need for additional cost required for investment in sensors and measurement devices. Thus, the scheme is very beneficial for
**FIGURE 13** Results for voltage profile at buses 11, 10, 13, 16 and 7 after 10% increase in distributed generation and load

**FIGURE 14** Results for reactive power compensation by inverters for the period at buses 11, 10, 13, 16 and 7 after 10% increase in distributed generation and load

**FIGURE 15** Results for voltage profile at buses 11, 10, 13, 16 and 7 after 10% increase in line impedance

**FIGURE 16** Results for reactive power compensation by inverters for the period at buses 11, 10, 13, 16 and 7 after 10% increase in line impedance
developing countries like Ghana that have limitations on the amount of financial investment that will be made into the network. It presents distribution system operators an offline planning methodology that utilises reactive power resources of DGs for voltage-regulation purposes in dealing with the changing grid conditions as demonstrated by the simulation results.

The sensitivity-fitting function used in this scheme must be recalculated once there is a major topology change, such as significant changes in load, generation or substation. This does not occur suddenly, however, and may take several months to occur. This provides enough time for network planners to recalculate the fitting function.

6 | CONCLUSIONS

This work presented a Q(U) control with adaptive functionality on weak MVGs with voltages close to their lower limit, especially during peak demand periods. It considered the uniqueness of voltage sensitivity for each bus and the stability of the voltage at the PCC without the need for communication facilities on the network.

To access the performance of the proposed concept, the model was implemented on a 16-bus MVG that was saddled with voltage-regulation challenges at the ends of the feeder. Based on the results obtained, the scheme was able to regulate the voltages even at the weak buses during both peak load demand and peak solar hours. In addition, these results were compared with those of the active CVC scheme and Q(U) control with generalized parameters. In general, the proposed concept performed better than the Q(U) control with fixed parameters and achieved a performance comparable to that of the CVC without communication facilities, and hence this scheme can be relied on to provide voltage-control function in networks where such facilities are absent, especially in developing countries.

The Q(U) with adaptive functionality as proposed in this work could be beneficial to network planners and operators, as it eliminates the burden of determining the Q(U) parameters of each DG integrated in the network for optimal performance and helps improve the voltage-regulation problem on weak MVGs. The drawback of this approach, however, is that any time a major topology change occurs in the network, the fitting function must be recalculated.

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