Decentralised voltage control for active distribution networks

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***Abstract*–The technical challenges imposed by increasing connection of distributed generation (DG), Distribution Network Operators (DNOs) require new voltage control schemes to manage the networks in a more active manner. In a conventional centralised scheme, voltage regulation is primarily performed at the substation according to the existing and predicted load downstream. However, this operation may leave other parts of the network where DG units are connected to experience problems such as voltage rise. Among the range of existing active network management schemes, a decentralised control wherein a distributed generator performs appropriate control actions at the point of connection to improve overall network performance may be a useful option. Aimed at minimising the impact of DG on the network's voltage profile, this work examines a decentralised control of DG. A power factor control–voltage control (PFC-VC) technique is demonstrated through a time-series analysis, considering firm and intermittent power generation. Results show that the proposed technique is able to effectively mitigate voltage rise.**

***Index Terms*—Active network management, distributed generation, distribution networks, voltage control.**

I. Introduction

A large expansion in the connection of new distributed generation (DG) capacity to the distribution networks has been seen in the last decade, mainly driven by the UK government's targets and incentives. Renewable generation technologies, such as wind power, will typically be connected to remote parts of medium and low-voltage distribution networks where they are particularly vulnerable to changes in network conditions. This presents Distribution Network Operators (DNOs) with several technical constraints that can limit the connection capacity of new DG. One of the most significant issues arising from the increasing integration of DG is voltage rise [1], [2].

In a traditional voltage control arrangement, voltage regulation is mainly performed by an on-load tap changer (OLTC) at a transformer substation. In order not to interfere with the existing voltage regulation, DG units are normally required by DNOs to operate within a power factor range (e.g., 0.95 leading/lagging), but due to commercial reasons, DG owners commonly maintain a constant power factor close (or equal) to unity. Being the generators unable to provide voltage support, voltage problems are therefore solved primarily by the OLTC transformers.

A range of active network management (ANM) schemes have been proposed offering a feasible solution that can mitigate the impact of DG connection, including voltage rise. Current ANM schemes may be classified as centralised, semi-coordinated and decentralised control strategies. The former provides voltage regulation from the substation to the rest of the network, potentially including a wide deployment of communication systems to coordinate different devices (OLTC, voltage regulators, etc.). The semi-coordinated and decentralised control strategies are, on the other hand, aimed at locally controlling the DG unit in an active way while coordinating it with a limited number of other network devices. These approaches can improve the overall network performance while limiting the need of large investment on communication systems. The OLTC at the substation can be, for instance, coordinated with the reactive power exchanges between the DG units and the feeders to improve the voltage profile [3]. The optimal settings of the OLTC and other network devices such as switched capacitors or static Var compensators, can also be used to minimise the power losses [4]. It has also been proposed, the use of genetic algorithms in order to obtain the optimal voltage control strategies [5]. In terms of only controlling the reactive power injection or absorption of DG units, a purely decentralised approach was presented in [6], where the network topology was used to calculate the reactive power needed to cancel out the effects of the active power injection.

In this work, a decentralised voltage control technique for a single generator is proposed to mitigate voltage rise. Here, at normal conditions, the generator will operate in constant power factor mode. Only at times when the voltage deviates above or below the statutory limits, the generator will be regulated to absorb or inject an amount of reactive power that suffices the voltage constraints at the connection point.

A simplified 3-bus 11kV distribution network with a single DG unit is studied. A time-series analysis (24 hours) is considered for both the load and generation (firm and intermittent). Normal and contingency (loss of a circuit) operation are investigated.

This paper is organised as follows. Section II explains the principle of the proposed technique. In Section III, the data corresponding to the simplified network and the adopted generation profiles are presented. Different DG penetrations are analysed. Finally, conclusions and future work are provided in Section IV.

II. Voltage Regulation and Decentralised Control

The increasing connection of DG has created a significant impact on the voltage profile of distribution networks, particularly, when operated under the traditional control arrangement.

In passive distribution networks, voltages are controlled by an OLTC transformer where voltage targets are set according to, for instance, seasonality. Depending on locations, these voltage limits may be flexible. Generally, the transformer's tap setting is adjusted to ensure that voltage at the end of the LV feeder does not exceed the lower limit. Nonetheless, the presence of new generation can cause a significant voltage rise in LV networks where lines are highly resistive.

A Power Factor Control-Voltage Control (PFC-VC) technique is proposed here based on [7]. It combines the behaviour of a generator's operation in two modes: constant power factor control (PFC) and voltage control (VC). In PFC mode, the P/Q ratio of a generator is kept constant, with the reactive power following the variation of the real power. In most cases, DG owners will operate at power factors close to unity to ensure the availability of the generator's full real power output. However, VC mode, where reactive power is injected or absorbed to compensate for voltage variation, can potentially help maintaining the voltages within the statutory limits. This is particularly helpful during certain demand-generation scenarios or even network configurations (e.g., outage of a line). Consequently, the proposed PFC-VC scheme combines the advantages of both operating modes.

In the proposed PFC-VC scheme, it is assumed that the operating power factor of a DG unit is permitted to vary, although within its reactive power capabilities. While the latter depends on the size and type of the generator, a 0.85 absorbing/injecting Vars is adopted in this work. The PFC-VC operational scheme is illustrated in Fig. 1. When the voltage at the connection point is within the statutory limits, the constant PFC mode is adopted. At times of voltage deviating from the limits, the generator will be assigned to VC mode.

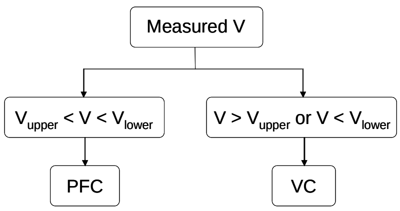


Fig. 1. Diagram of the PFC-VC operational scheme.

III. Case Study

In this section, firstly the characteristics of the analysed network, including demand and generation, are presented. Then, results obtained for the different cases are discussed.

A. Network Characteristics

The simplified 3-bus 11kV distribution network used in this work is shown in Fig. 2. An OLTC transformer steps down 33kV at bus 1 to 11kV at bus 2. The impedance for the line section 2-3 (double circuit) is 3.802+*j*3.042pu. For the contingency analysis, i.e., considering the outage of one of the parallel lines, the impedance becomes 1.901+*j*1.521pu. A DG unit and a single demand point are connected to bus 3.

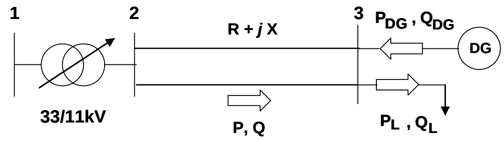


Fig. 2. Simplified 3-bus 11kV distribution network. S_{base}=100MVA.

B. Demand and generation profiles

Given that firm and intermittent DG are considered in this study, profiles for combined heat and power (CHP) and wind power generation are adopted. Hourly demand and wind speed data correspond to the area of central Scotland, measured in 2003 [8]. The wind data has been processed and applied to a generic wind power curve [8]. The 24-hour period of 14th August 2003 (shown in Fig. 3) was selected. This specific summer day presented the highest wind power outputs during August, thus can be considered as a "worst case scenario" with minimum demand and maximum generation. The maximum and minimum demand during this 24-hour period are 2.2 and 1.43MW, respectively. The maximum demand in 2003 is 4,298.5MW (used to calculate p.u. values). Load power factor is equal to 0.95 lagging (absorbing reactive power).

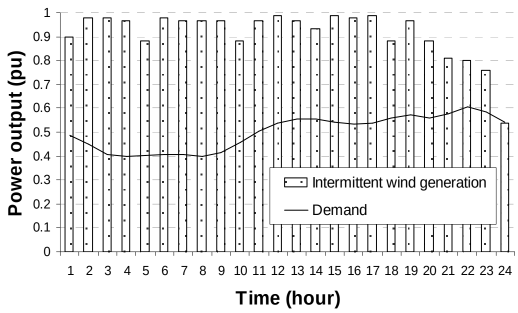


Fig. 3. Daily demand and generation profiles [8].

C. Results

The proposed control scheme will be applied to the two types of generation considering the 24-hour period. First, the normal operation (double circuit of line section 2-3) of DG is studied, considering different levels of capacity penetration. The contingency case, where the outage of one parallel line occurs during two hours, is investigated in the sequence. The methodology was developed in Python language and simulated using PSS/E software.

In the analysis, the PFC-VC scheme was tested against the, constant power factor control mode (PFC) and the reactive power control approach (Q* control). The latter approach, presented in [6], alleviates voltage rise problems by injecting or absorbing an amount of reactive power calculated as a function of the line impedance and the active power output of the DG unit (see the Appendix for further details).

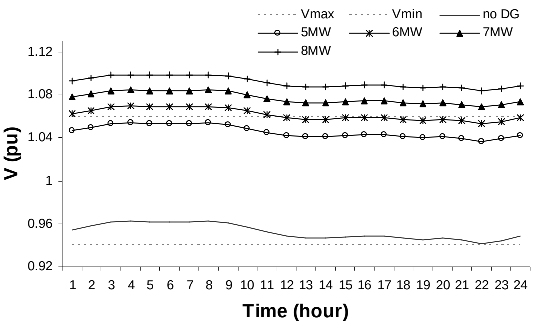
Normal Operation

A CHP unit, representing a firm power output type of generation, is analysed first. Different nominal (maximum) capacities are examined, from 5 to 8MW, operating at unity power factor. As it can be observed in Fig. 4-a, increasing MW output of the CHP unit operating in constant power factor mode (PFC) creates an unacceptable voltage rise, particularly when the generator is larger than 6MW. Using the Q* control, the generator absorbs an amount of reactive power that is beyond its reactive capability in order to reduce the voltage rise (Fig. 4-b). This results in a sudden drop of voltage at which, in some cases, the voltage profile may be worsened. The proposed PFC-VC scheme is able to maintain the upper voltage level for any DG output (Fig. 4-c).

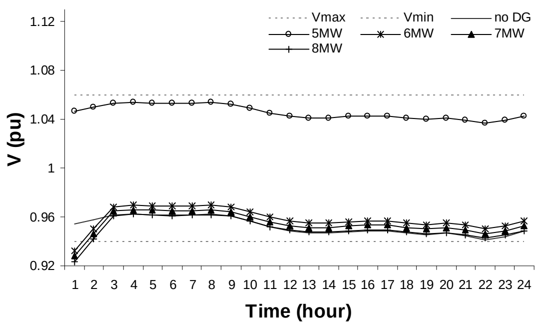
Comparisons of voltage profiles and tap positions for the 6MW CHP unit with PFC, Q* control and PFC-VC are shown in Fig. 6. It can be seen that there is an increase in tapping actions when Q* control approach is used while for PFC and PFC-VC, no tap change occurs.

Wind generation was considered for the intermittent type of DG. Different nominal outputs (from 5 to 8MW, operating at unity power factor) were also analysed. Results show that, as expected, the larger the wind farm (PFC mode) the more voltage rise problems (Fig. 5-a). When adopting the Q* control, similar results to that of the firm generation are obtained. The approach attempts to reduce the voltage rise by absorbing reactive power. As seen in Fig. 5-b, the voltage profile rapidly drops as a consequence. On the other hand, with the proposed PFC-VC, the voltage profile is improved and the upper voltage level is always maintained (Fig. 5-c).

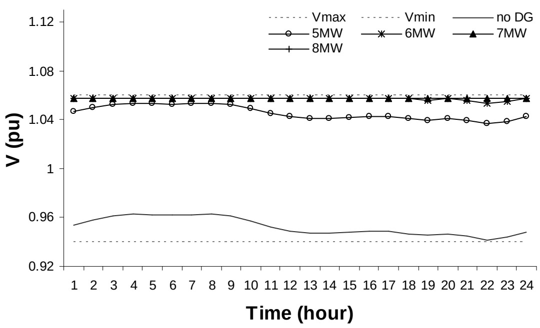
Focusing on the wind farm generating 7MW (Fig. 7), likewise, there is a change in the tap positions when applying PFC and Q* control approach while the PFC-VC scheme produces zero tap change. This could be beneficial when considering a larger time interval, i.e. annual demand and wind profiles. Adopting the PFC-VC scheme could result in less tapping actions, extending the transformer's lifetime.



(a)

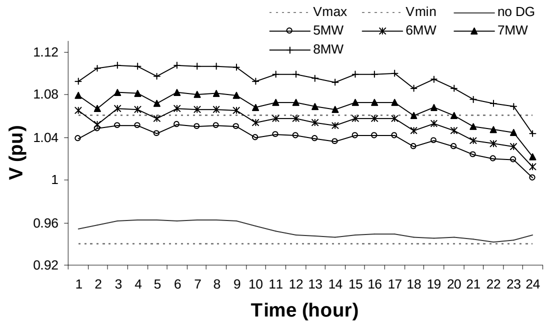


(b)

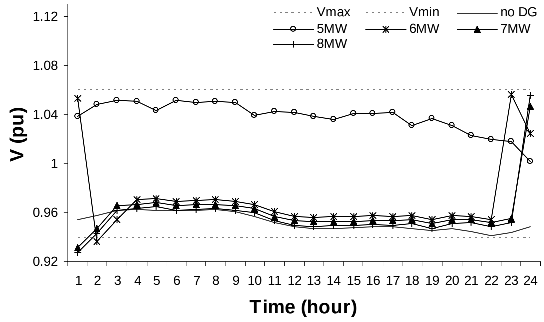


(c)

Fig. 4. Voltage profiles at bus 3 for increasing MW of the firm generation (CHP) operating with PFC (a), Q* control (b) and PFC-VC (c).



(a)



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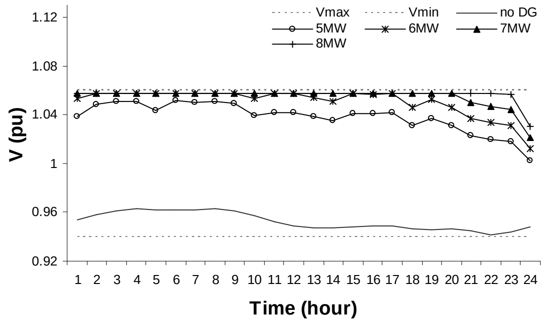
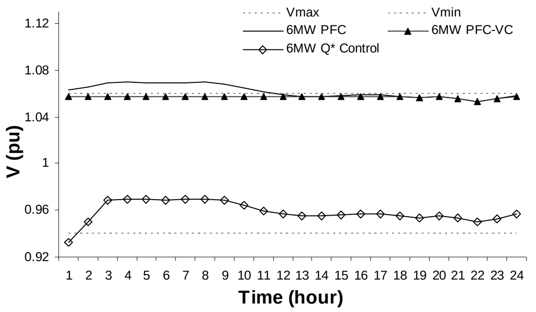
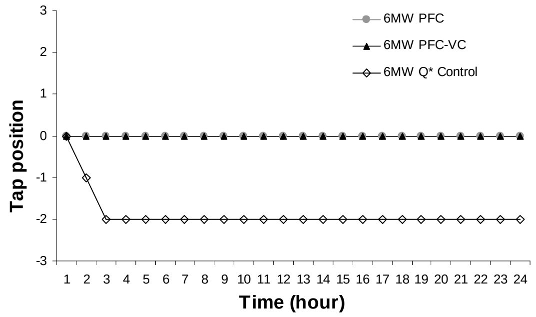


(c)

Fig. 5. Voltage profiles at bus 3 for increasing MW of the intermittent generation (wind turbine) operating with PFC (a), Q* control (b) and PFC-VC (c).

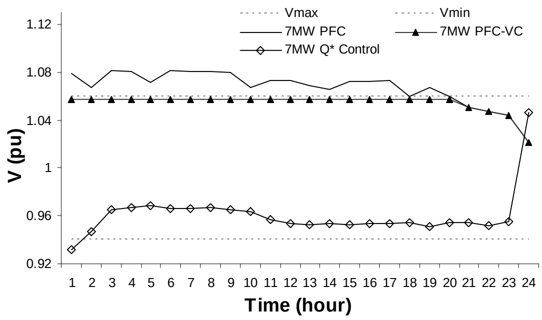


(a)

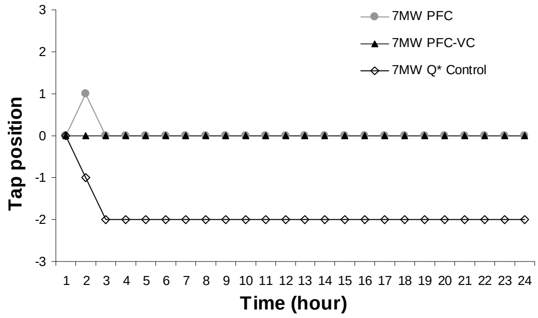


(b)

Fig. 6. Comparisons of voltage profiles (a) and tap positions (b) for each scheme at 6MW CHP.



(a)



(b)

Fig. 7. Comparisons of voltage profiles (a) and tap positions (b) for each scheme at 7MW wind farm.

Contingency Operation

Changes in the network configuration might produce adverse effects on the voltage regulation strategies previously analysed. Here, the outage of one parallel line (bus 2-bus 3) between 6-8am will be considered. For the firm generation, the 5MW CHP unit was studied. A sudden voltage step change exceeding the upper limit during the line outage period appears when using the constant power factor control mode (PFC, Fig. 8). The Q* control, on the other hand, produces a sudden decrease in voltage. As for the PFC-VC scheme, the CHP unit is able to securely mitigate the voltage step change due to the outage.

Similar results can be observed in the intermittent generation analysis. As shown in Fig. 9, a sudden voltage rise is detected during the line outage period (PFC). In response to this, the PFC-VC scheme acts to improve the network's voltage profile and maintains the voltage threshold whereas the Q* control approach causes a rapid decrease in the voltage level of the connection point.

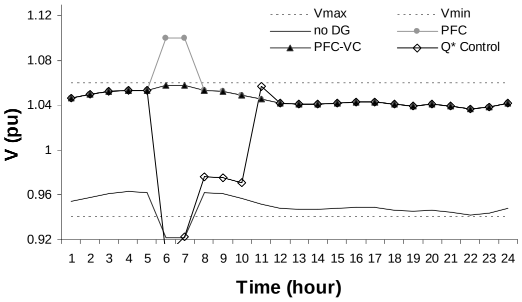


Fig. 8. Voltage profiles at bus 3 of a double circuit network for a 5 MW CHP unit operating with PFC, PFC-VC and Q* control.

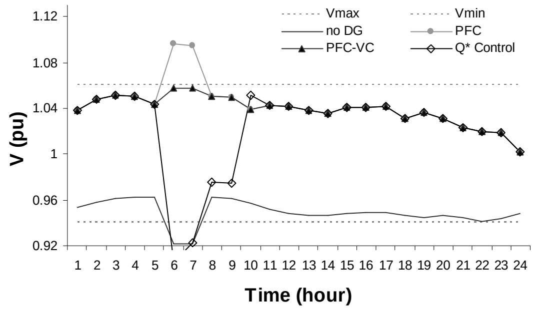


Fig. 9. Voltage profiles at bus 3 of a double circuit network for a 5MW wind farm operating with PFC, PFC-VC and Q* control.

IV. Conclusions

In this study, a power factor control-voltage control approach for DG was proposed in order to provide a robust voltage regulation strategy. Firm and intermittent distributed generation were considered under two key cases: increased penetration of DG and changes in the network topology. Simulations in a 24-hour analysis were carried out. Results show that the PFC-VC approach for DG is able to maintain the network voltage within the statutory limits, whereas a generator operating in constant power factor mode contributed to voltages outside the desired range. In the worst cases when a large amount of power from DG is connected, the generator operated with constant power factor created an unacceptable voltage rise above the upper limits while the PFC-VC responded efficiently to improve the network's voltage profile. Results from both scenarios also show that the use of Q* control approach could worsen the voltage level. The PFC-VC scheme was able to restrain the voltage rise and maintain the network's voltage profile.

Future work will concentrate on improving the DG-OLTC coordination considering a more complex distribution network. The effect of DG units operating in different modes while situated close to each other will also be explored. Intermittent generation considering different levels of variability of wind power output under various time intervals will also be examined. The proposed decentralised approach might represent a feasible solution particularly for rural networks where major investments required by sophisticated centralised schemes can not be justified.

V. Appendix

The distributed reactive power control approach (Q* control) to mitigate voltage rise caused by active power injection from distributed generation consists of finding the value of reactive power required (Q_G*) such that the voltage rise caused by the DG unit's active power output (P_G) is minimised according to [6]. By knowing that the complex current injected by the distributed generation unit may be estimated as

$$\bar{I}_G = \left(\frac{P_G + jQ_G}{\bar{V}_G}\right)^* = \frac{P_G - jQ_G}{V_G \cos\delta - jV_G \sin\delta} \qquad (1)$$

where δ is the angle difference between the complex voltages at the distributed generation unit connected bus ($\bar{V}_G$) and the secondary side of the transformer (equivalent to V_3 and V_2, respectively, as shown in Fig. 2). By solving the quadratic equations resulting from writing the zero voltage drop equation due to (1) into real and imaginary parts, the amount of Q_G* can be approximate by

$$Q_G * \approx \frac{X}{R^2 + X^2} - \sqrt{\left(\frac{X}{R^2 + X^2}\right)^2 - P_G{}^2 + \frac{2RP_G}{R^2 + X^2}} \qquad (2)$$

where R and X are the feeder resistance and impedance, respectively (see Fig. 2). The resulting reactive power (Q_G*) is used to solve the voltage rise problem induced by P_G.

Acknowledgement

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