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Minimizing the Reactive Support for Distributed Generation: Enhanced Passive Operation and Smart Distribution Networks

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***Abstract*— Renewable distributed generation (DG), primarily wind power, will represent the lion's share of the new generation capacity that will be connected to distribution systems. However, while both firm and variable generation present our traditionally passive distribution networks with well established technical challenges, the requirements and practices related to the power factor operation of these generation plants might lead to undesirable effects at the transmission level with the reactive power support needed by high penetrations of DG capacity potentially impacting on weak areas of the transmission grid. In this work, this problem is formulated as the minimization of the reactive support for DG and is investigated using two different operational perspectives: adopting passive but enhanced power factor and substation settings, and implementing Smart Grid control schemes. These two approaches are modeled using a tailored multi-period AC Optimal Power Flow technique that caters for the variability of demand and generation, and considers N-1 contingencies. The results demonstrate that the enhanced passive approach is able to achieve a performance almost as good as smart grid control without the need for any additional investment.**

***Index Terms*—Distributed generation, smart grids, optimal power flow, N-1 contingencies, wind power.**

I. Introduction

ENVIRONMENTAL and fuel security concerns have been translated in the last decade into targets set by governments to diversify their energy mixes. In 2007, European leaders signed up to an EU-wide target where 20% of their overall energy needs have to be sourced from renewable energy sources by 2020. A large volume of renewable generation capacity is therefore expected to be connected to both transmission and distribution networks. In the UK alone, 10-GW of distributed generation (DG) capacity have been forecast by Distribution Network Operators (DNOs) to connect in the period of 2010-2015 [1], with wind power potentially having a significant share.

Although DG presents distribution networks –traditionally designed as passive circuits– with well established technical challenges [2], current requirements and practices related to the power factor operation of these generation plants might lead in the future to undesirable levels of reactive power absorption from the transmission grid, presenting voltage security issues [3, 4].

Depending on the characteristics of the distribution network and where a potential generation plant will connect to, specific reactive power (or voltage support) capabilities will be required. In most European countries it is common for DNOs to require generators to be capable of operating within a given power factor range. In the UK, for instance, the range is 0.95 inductive/capacitive [5]. While in certain cases this minimum requirement might change slightly due to the particularities of the local distribution circuit and to comply with the transmission grid code, the large majority of DG operators in countries with similar schemes will adopt unity power factor (or the closest possible) in order to maximize their profit as it is solely based on MWh. In rural areas, where a high penetration of renewable generation exists, unity power factor is often not possible as voltage rise is a serious issue. Electricity Supply Board Networks, the Irish distribution network operator, requests wind generators to keep power factor between 0.92 and 0.95 inductive [4]. In Spain, also with large volumes of distribution-connected renewable generation capacity, network operators have realized the importance of adequate reactive power regulation and in 2007 introduced an incentive-based time-of-the-day power factor settings [6] to encourage generators to (voluntarily) help network operation.

Local statutory requirements mean that DG plants might always or partly draw reactive power. The aggregated effect of such absorption combined with the (weak) var support capability of local transmission grids might result in unacceptable depletion of reactive reserves for the system operator or poor voltage profiles [3, 7, 8]. The occurrence of coincident transmission circuit outages may act as a limit on DG penetration in such cases [9]. Although this problem could be tackled by reactive power compensation at the distribution

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substation with capacitors or static var compensators, the corresponding investment would potentially have to be borne by the DNO. A less capital intensive solution would be to make use of the significant reactive power capabilities of DG plants already required by connection codes [10].

This paper is focused on the benefits that better use of the reactive power capabilities of DG units can deliver to distribution and transmission systems. Moving beyond the optimal sizing and siting of DG, covered extensively in the literature [11-18], this work examines the scope for minimizing the reactive support provided by the transmission network to the distribution network. Two alternative operational perspectives are investigated: (1) the adoption of enhanced pre-defined fixed generator power factors and substation settings, termed here as Enhanced Passive Operation (EPO), and; (2) the implementation of Smart Grid control schemes using control and monitoring schemes to optimize power factor and voltage settings in real-time to better integrate and exploit distribution network assets and participants. The former extends the complexity of the methodology presented by the authors in [3] by taking into account the non-linearities of the problem, as well as adopting a more robust and realistic approach. The Smart Grid approach considers active control of the power factor capabilities of the generators and the real-time control of substation on load tap changers. These two approaches are modeled using an optimization framework previously developed in [18] where a tailored multi-period AC Optimal Power Flow technique is used to cater for the variability of demand and generation, as well as thermal and voltage limits. Here, this novel framework is extended to also consider contingencies (e.g., N-1 security).

This paper is laid out as follows: Section II briefly presents the mathematical formulation of the problem from the Enhanced Passive Operation and Smart Grid perspectives. In section III, a simple example is used to show how both schemes work. In section IV, the methodology is applied to a typical Irish distribution network with the results from the two approaches showing that the EPO approach is able to achieve broad performance parity with Smart Grid control schemes suggesting that it could be used as an interim alternative.

II. Enhanced Passive Operation And Smart Distribution Network: Problem Formulation

The AC Optimal Power Flow (OPF) technique [19], traditionally used for economic dispatch of transmission-connected generation, has also proved to be a very robust and flexible tool for problems related to DG planning and optimization [18, 20-23]. Here, the AC OPF, formulated as a non-linear programming problem, will be used as the framework for the two different approaches: the enhanced passive operation and the smart grid-based operation.

In addition to accounting for thermal and voltage constraints, the OPF is tailored to cater for the variability of both demand and generation (multiple periods or demand/generation scenarios) [18, 22], as well as for N-1 contingencies (e.g., loss of a line) [20, 24]. The latter, also known as Security Constrained OPF, ensures that no limits are exceeded even during contingencies that might occur in the system. Effectively multiple topologies are simultaneously analyzed.

Optimization analysis of systems with variable renewable generation requires use of production data at around hourly resolution. This creates a substantial computational burden particularly when using medium to large networks, where multiple DG units and control schemes are concerned. The use of multi-periods reduces this burden yet, critically preserves the behavior and inter-relationships between resources and demand [18, 22]. Here, discretization and aggregation processes are applied according to the characteristics of 'similar' periods. For example, Fig. 1 (top) presents a week-long snapshot of hourly demand and wind power data for Ireland in 2006 [3]. Fig. 1 (bottom) shows the discrete values following allocation of the original data into a series of 7 bins covering specific ranges ({0}, (0,0.2pu], (0.2pu,0.4pu],…, (0.8pu,1.0pu), {1.0}) in which the mean values (e.g., 0.3pu for the (0.2pu,0.4pu] range) characterize each new hour. The aggregation process groups hours in which the same combination of demand and generation occur. The arrows in Fig. 1 (bottom) show hours where demand is 0.7pu and wind is 0.10pu; these conditions occur for a total of 18 hours in this particular week. This combination constitutes a 'period' to be evaluated along with other combinations of different overall duration in the optimization problem.

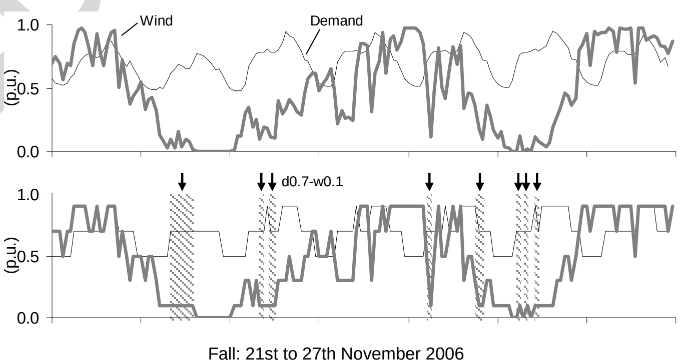

Fig. 1. (Top) Week hourly demand and wind power for Ireland, 2006 [3]. (Bottom) Discretized data processed before aggregating the coincident hours of each demand-generation scenario.

The multi-periodicity of demand/generation scenarios and multiple topologies from N-1 contingencies, is achieved by providing each scenario, *m*, and topology, *k*, with a different set of power flow variables. These are bound by a unique, *inter-period* set of variables for the generation power factor angles (a proxy of their power factors) and the voltage at the substation – all used throughout the analysis.

For a given installed capacity of DG, the objective function of this tailored OPF will be the minimization of the total reactive power hours (varh) provided by the grid supply point to the distribution network. The reactive power, however, at a given period has to be squared (or its absolute value applied) in order to avoid promoting overall capacitive behavior of the generation plants; an approach that ensures more consistency than that presented previously in [3]. Thus, considering the main network topology (normal operation), k_{MAIN}, and multiplying the imports/export of reactive power of each period m by its corresponding duration, τ_m, the objective function is formulated as follows:

$$\text{Min} \sum_{m \in M} q^2_{GSP,m,k_{\text{MAIN}}} \tau_m \qquad (1)$$

subject to the typical AC OPF constraints across all periods (M) and all topologies (K), i.e., $\forall m \in M$ and $\forall k \in K$. The constraints (below) include bus voltage and branch thermal limits as well as N-1 security. Other constraints such as voltage step change, which can be implemented within the same framework [21], are not considered here to ensure clarity. Voltages at bus b (B, set of buses) are constrained by max/min levels $V_b^{(+,-)}$:

$$V_b^- \le V_{b,m,k} \le V_b^+ \quad \forall b \in B \qquad (2)$$

Power flows at each end of lines and transformers, l (L, set of lines):

$$\left(f^{(1,2),P}_{l,m,k} \right)^2 + \left(f^{(1,2),Q}_{l,m,k} \right)^2 = \left(f_l^+ \right)^2 \quad \forall l \in L \qquad (3)$$

where $f^{(1,2),P}_{l,m,k}$ and $f^{(1,2),Q}_{l,m,k}$ are the active and reactive power injections at each end of the branch (denoted 1 and 2) and f_l^+ is the apparent power flow limit on the branch. Active and reactive power injections into each end of the lines are governed by Kirchhoff's voltage law:

$$f^{(1,2),(P,Q)}_{l,m,k} = f^{KVL(P,Q)}_{l,(1,2),m,k}(\mathbf{V}_{m,k}, \delta_{m,k}) \quad \forall l \in L \qquad (4)$$

where $f^{KVLP}_{l,(1,2),m,k}(\mathbf{V}_{m,k}, \delta_{m,k})$ and $f^{KVLQ}_{l,(1,2)}(\mathbf{V}_{m,k}, \delta_{m,k})$ are standard Kirchhoff voltage law expressions. With on load tap changing transformers and voltage regulators, the appropriate terms in (4) for the voltage at the start bus of the line must be divided by the tap ratio $t_{l,m,k}$ within the range $t_l^- \le t_{l,m,k} \le t_l^+$.

Kirchhoff's current law describes the active and reactive nodal power balance, $\forall b \in B$:

$$\sum_{l \in L | \beta_l^{1,2} = b} p^{\text{L}}_{b,m,k} + d_b^P \eta_m = \sum_{g \in G_b | \beta_g = b} p_g \omega_m + \sum_{x \in X | \beta_x = b} p_{x,m,k} \qquad (5)$$

$$\sum_{l \in L | \beta_l^{1,2} = b} q^{\text{L}}_{b,m,k} + d_b^Q \eta_m = \sum_{g \in G_b | \beta_g = b} p_g \omega_m \tan(\phi_g) + \sum_{x \in X | \beta_x = b} q_{x,m,k} \qquad (6)$$

Here, $(p,q)^{\text{L}}_{b,m,k}$ are the total power injections into lines at bus b; and $d_b^{(P,Q)}$ are the peak active or reactive demands at the same bus. Generation units have constant maximum active power capacities, i.e., $p_g = p_g^{\text{constant}}$. The generator output in each period m, that varies with the renewable resource is described by its production relative to the capacity, ω_m, i.e., the *instant* power output is $p_g \cdot \omega_m$. Similarly, η_m expresses the demand level in period m relative to the overall peak value, i.e., the *instant* load is $d_b^{(P,Q)} \cdot \eta_m$. This captures the variability in load and resource (as presented in section 2).

The distribution network has external connections at the grid supply substation and may have interconnectors. It is assumed that both can export power so the import/export constraints x (X, set of external sources), are:

$$\left. \begin{aligned} p_x^- \le p_x \le p_x^+ \\ q_x^- \le q_x \le q_x^+ \end{aligned} \right\} \quad \forall x \in X \qquad (7)$$

where the grid supply point is the reference bus b_{GSP} with zero voltage angle, i.e., $\delta_{b_{GSP}} = 0$.

A. Enhanced Passive Operation of DG units and the On Load Tap Changer

Distributed generation plants typically operate at a constant power factor that presents most benefit for active power production. However, connection codes mean that actual reactive power capabilities are significant (e.g., $\cos(\phi_g) = 0.90$ inductive/capacitive). By incentive or by requirement, generators could operate at enhanced pre-defined fixed power factors that, when combined with adequate substation (voltage) settings, minimize reactive support from the transmission grid whilst ensuring voltage, thermal and security limits [3].

To obtain the set of *fixed* power factors that minimizes (1), the power factor angle of each generator, ϕ_g, will become a variable for the entire studied horizon and contingencies. These power factor angles will be constrained by the angles corresponding to the limiting power factors ($\phi_g^{(+,-)}$):

$$\phi_g^- \le \phi_g \le \phi_g^+ \qquad (8)$$

Target voltage settings at the substations' on load tap changer are normally defined seasonally to cater for voltage drops during maximum load whilst ensuring excessive voltage rise does not occur where DG connections exist. By coordination of the reactive power operation of the generators with the substation target voltage, the overall performance of the system can be significantly increased [24]. Thus, for the EPO approach, the voltage at the substation secondary, $V_{b_{OLTC}}$, is considered as a variable whose final value (as with the power factor angles) is constant across all periods and for all network topologies.

$$V_{b_{OLTC},m,k} = V_{b_{OLTC}} \qquad (9)$$

B. Smart Grid Control Schemes

To facilitate understanding of the potential influence of Smart Grid control schemes on the minimization of the reactive power support from the transmission grid two schemes have been implemented: adaptive power factor control and coordinated voltage control [18]. Rather than applying a fixed enhanced power factor and voltage settings across all periods (EPO approach), the optimization is conducted independently for each period, mimicking time-domain control. This planning-orientated analysis assumes that measurement and control infrastructures to support the control schemes are in place, and that response delays are negligible.

With the envisaged adaptive power factor control generation plants are able to provide a 'dispatchable' power factor. To incorporate this into the OPF framework, the power factor angle of each generator, $\phi_{g,m}$, is considered as a variable at each of the analyzed periods, and constrained by the corresponding limiting power factor angles:

$$\phi_g^- \le \phi_{g,m} \le \phi_g^+ \tag{11}$$

As for the coordinated voltage control, at each period the secondary voltage of the on load tap changer will be treated as a variable, rather than fixed, parameter, while maintaining its value within the statutory range:

$$V_{b_{OLTC}}^- \le V_{b_{OLTC},m,k} \le V_{b_{OLTC}}^+ \tag{10}$$

III. Applying the EPO and Smart Grid Schemes

This section briefly exemplifies how both the EPO and the Smart Grid schemes are applied to a distribution circuit with DG. Fig. 2 shows a test feeder capable of exporting power upstream. Voltage limits are $\pm$ 10% of the nominal values and the corresponding line data are in p.u. on a 100-MVA base. Load bus A also has a 7-MW CHP unit (constant output) connected. A simple demand profile of 2-MW minimum and 4-MW maximum demand, applies for a duration of 2000 and 6760 hours, respectively. This simple case study is characterized by only two demand/generation periods (scenarios) as the CHP has constant production. To simplify the analysis the target voltage at bus Tx is kept at 1.00pu in all cases (no coordinated voltage control). Both techniques were coded in the AIMMS optimization modeling environment [25] and solved using the CONOPT 3.14A NLP solver.

With the CHP unit operating at (say) 0.95 inductive power factor, the total reactive power drawn in a year from the transmission network would be 32.3-Gvarh. For the EPO approach, a single, fixed power factor can be found that minimizes the reactive power drawn whilst also meeting thermal and voltage constraints. For this case, operating the CHP unit at 0.984 capacitive power factor sees the feeder export a modest 7.6-Mvarh of reactive power, a very significant reduction. The Smart Grid approach will find a separate optimal power factor for each of the two periods mimicking idealized control able to change generator power factor settings as required. Two capacitive power factors of 0.992 and 0.981 are obtained for minimum and maximum demand, respectively. These counteract the local reactive demand (including losses) to deliver zero net reactive draw (0-varh), exceeding the performance of the EPO approach.

This example illustrates how the schemes work, but the next section shows their application to challenging realistic situations in an actual rural distribution network with several renewable generators and additional voltage control schemes.

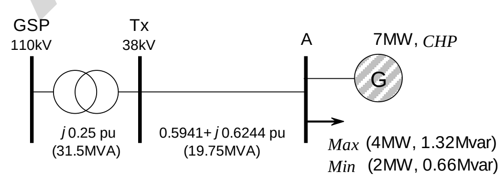

Fig. 2. 38-kV test feeder with one CHP unit (constant generation).

IV. Case Study

Here, the technique is applied to an actual section of the Irish distribution network with rural characteristics that, although relatively small, is typical of the type of networks where most wind generation is connecting. The business as usual operation is discussed followed by the EPO and Smart Grid control schemes.

A. 5-bus Irish Network

The one-line diagram of a typical rural section of the Irish 38-kV distribution network is shown in Fig. 3. Corresponding line data (S_b=100-MVA) is included in Table I. The feeders are supplied by one 31.5-MVA 110/38-kV transformer (capable of handling reverse power flows). The voltage at the grid supply point is assumed to be nominal. In the original configuration (no DG), the on-load tap changer at the substation has a target voltage of 1.078pu (41-kV) at the busbar, well within the $\pm$ 10% nominal voltage limits of Irish practice. The maximum demand of the network is 15.12-MW. The main network topology, k_{MAIN}, is the one with line A-S open, as presented in Fig. 3. The N-1 contingencies considered are the outages of lines Tx-A and Tx-S as shown in Fig. 4.

In order to investigate how high penetrations of generation capacity with a diverse number of sources and locations will require different power factor settings, as well as particular voltage settings for the on-load tap changer, four wind power plants and a biomass power plant are connected to the network. The total installed capacity is 32-MW (see Fig. 3), exceeding the total peak demand by 110%. The generators are capable of providing power factors in the range 0.90 inductive/capacitive. Under current Irish connection requirements the *business as usual* scenario would see all generators operated at 0.95 inductive power factor (absorbing reactive power).

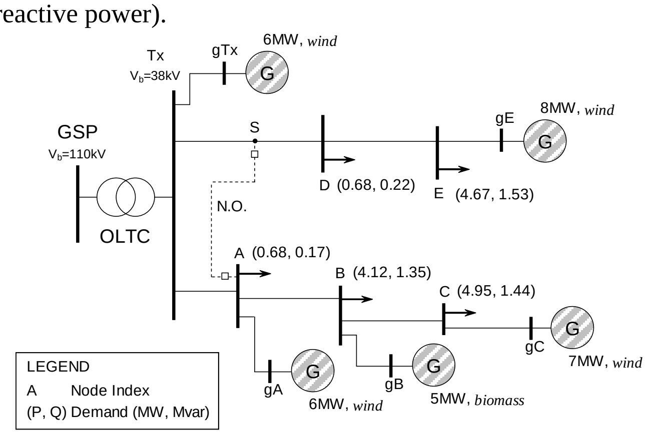

Fig. 3. 38-kV 5-bus network one-line diagram during maximum load conditions. Five distributed wind power generation sites are considered.

TABLE I
Line and Transformer parameters for the 38-kV 5-bus network

Line	R	X	Smax
GSP - Tx	-	0.2500	0.3150
Tx - A	0.0296	0.0863	0.3817
A - B	0.5941	0.6244	0.1975
B - C	0.3875	0.4072	0.1975
Tx - S	0.0669	0.0800	0.3817
S - D	1.0591	1.1130	0.1975
D - E	0.1550	0.1629	0.1975

Line	R	X	Smax
A - gA	0.1292	0.1357	0.1975
B - gB	0.1292	0.1357	0.1975
C - gC	0.1292	0.1357	0.1975
D - gD	0.1292	0.1357	0.1975
E - gE	0.1292	0.1357	0.1975
A - S	0.0697	0.0733	0.1975

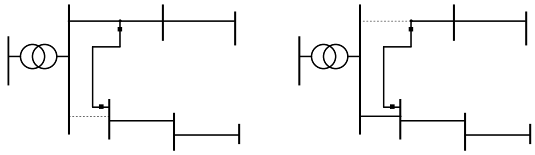

Fig. 4. N-1 topologies considered. Dashed lines indicate outages.

As set out in section 2, the time-varying characteristics of demand and (wind) generation over a given time period are handled with aggregated output/demand scenarios instead of the full output/demand time series. A year's hourly data for demand, two wind generation profiles (one per feeder) and a biomass generation profile are broken into 5 demand ranges ([0,20%],(20%,40%],…) and 7 ranges per generation profile ({0}, (0,20%], (20%,40%],…,{100%}). An example of this discretization is shown in Fig. 5 for the week of the 21st November 2006. The process reduces the computationally demanding 8760 hour time series to only 198 periods, whilst keeping sufficient representation of the original load and generation behavior. The original load factor of 0.64, and the generation capacity factors of 0.40, 0.34 and 0.86, for wind 1, 2 and the biomass profiles, respectively, were marginally affected by this. Table A-I (Appendix) presents the number of aggregated hours for each of the considered periods (i.e., demand/wind generation 1, 2/biomass generation scenarios).

B. Business As Usual (BAU) Operation

The BAU operation of the 38-kV network from Fig. 3 will result in a high reactive power demand to be supplied by the transmission grid given the inductive behavior of loads and generators. Without generation units the network has annual imports of 33.4-Gvarh and 76.6-Gvarh when wind farms operate at constant 0.95 inductive power factors.

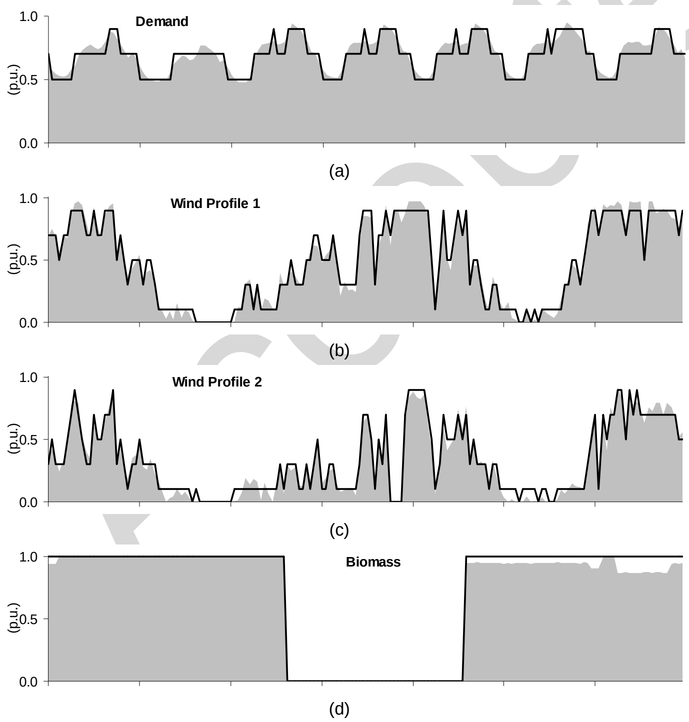

Fig. 5. (Grey areas) Week hourly (a) demand, (b, c) wind and (d) biomass power generation profiles for Ireland, 2006 [3].; (Thick black lines) Discretised data processed before aggregating the coincident hours of each demand-generation scenario.

By recomposing the results from the multi-period analysis it is possible to create the *quasi* time-series behavior in order to illustrate the different reactive power requirements. The week presented in Fig. 5 was selected to show the behavior of the proposed methodologies during particular scenarios, such as low biomass power output/high wind power output and vice-versa. Fig. 6-a shows the breakdown of the total imports of reactive power. As expected, the Mvarh required by all the generation units follow the combined generation pattern, with the 1st, 4th and 7th days presenting larger absorption (due to higher production). It can also be noticed that these larger volumes of generation result in larger reactive power losses.

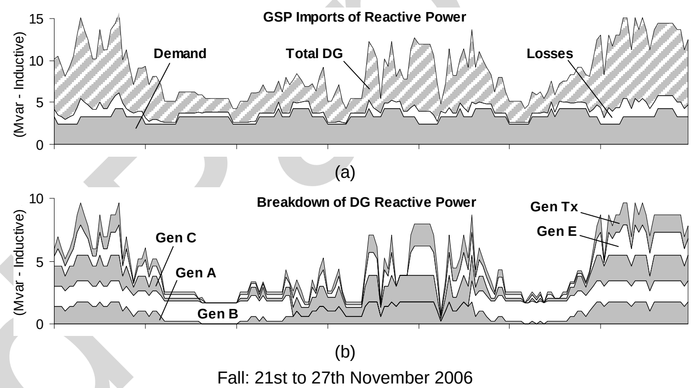

Fig. 6. BAU Approach: (a) Breakdown of the imports of reactive power (inductive behavior) into demand, losses and the reactive requirements of generation units. (b) Breakdown of the total reactive power requirements (inductive behavior) for each generation unit.

The breakdown of the reactive power imports for each generator is also presented in Fig. 6-b. Given the relatively similar nominal capacities of the generators, and the fact that they all operate at 0.95 inductive power factors, the Mvarh required by each of them is directly proportional to their real power output. This can be seen during the second half of the last day, where all the generators have large exports. Another example occurs during the second half of the second day, when only biomass generation is available.

C. Enhanced Passive Operation (EPO)

Finding the most adequate, or 'optimal', power factor and voltage settings that minimize the reactive power consumption from the transmission grid, i.e., solves (1), is not necessarily a complex task when only a snapshot of demand and generation is considered [24]. However, given the inherent variability of demand and (renewable) generation, such a single-period analysis will not result in the overall minimization of varh, and could potentially lead to thermal and/or voltage issues (with or without N-1 security constraints). The corresponding complexity of taking into account this variability can be dealt with by the multi-period AC OPF technique. Fig. 7 shows the net annual Gvarh imports resulting in each of the cases analyzed considering the variability of demand and generation (wind and biomass).

Table II presents the corresponding enhanced settings.

If only enhanced, independent power factor settings are applied (pf), the net annual imports from the BAU case (76.6-Gvarh) decrease by more than 70% taking into account only the normal operation of the network (k_{MAIN}), and by 55% with N-1 contingencies being considered. It can also be noted that, the N-1 constraint makes generation units B and E become more inductive. In fact, the resulting new power factors are mainly driven by voltage (rise) constraints produced by the reverse active power flows. Hence, while it is possible for generators A and Tx (electrically close to the substation) to have a capacitive behavior, the other generation units have to operate mainly with inductive power factors.

Incorporating the target voltage at the on load tap changer as a variable in the formulation (pf+V case) decreases the required reactive power support from transmission even further. With only k_{MAIN} , net annual imports of 3.1-Gvarh are possible. However, including N-1 contingencies this figure goes up marginally, resulting in 3.2-Gvarh imported, i.e., approximately 4% of the BAU requirements. In terms of the resulting power factors, the lower values for the target voltage at busbar (originally 1.078pu), made viable a dominating capacitive behavior (although the security constrained case required generator C to be inductive).

For the same week, Fig. 8 shows the quasi time-series behavior of the reactive power requirements of the network when adopting the EPO approach (pf+V, N-1 case). From the results in Fig. 8-a and Fig. 8-b it is evident that the generators, as a whole, counteract the inductive requirements of the load and losses, resulting in much less inductive power being demanded from the transmission grid compared to the BAU (see Fig. 6-a). Only during situations where generation is large relative to demand (e.g., days 1 and 7), the network becomes capacitive, providing reactive Mvar support to the transmission grid. However, although this occurs half of the time during the studied year, the maximum reactive power exported to transmission is fairly small and never exceeds 1.3-Mvar. The variability of the reactive power requirements of each generation unit, 'proportionally' following their corresponding real power outputs, can also be seen in Fig. 8-c.

The EPO methodology is clearly able to find the enhanced settings for both the power factor of generation units and the target voltage at the substation busbar in order to minimize the varh demanded by the distribution network. The reduction across the year is substantial and can considerably improve operation of the local transmission system without sophisticated control systems.

It is also evident that the voltage setting of the substation on load tap changer plays a major role, providing more flexibility and allowing a better operation of the network and distributed generation units. The proposed methodology also shows the importance of considering N-1 contingencies as they create a more complex search space for the enhanced solutions. This effect is particularly noticeable when only the power factors are adjusted (i.e., pf case in Fig. 7), although still advantageous compared to the BAU case.

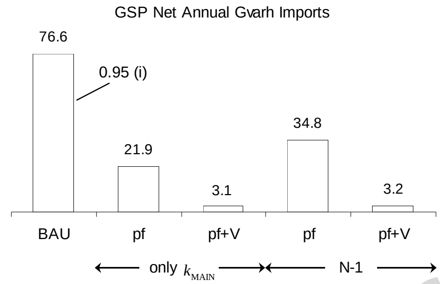

Fig. 7. Net annual Gvarh imports resulting from the cases considering fixed enhanced settings for power factor (pf) and the target voltage at the on load tap changer (+V), as well as N-1 constraints.

TABLE II
ENHANCED SETTINGS FOR THE CASES PRESENTED IN FIG. 7

DG unit	Enhanced Power Factor			
	only k_{MAIN}		N-1	
	pf	pf+V	pf	pf+V
A	0.900 (c)	1.000	0.900 (c)	0.900 (c)
B	0.976 (c)	0.900 (c)	0.999 (i)	0.900 (c)
C	0.900 (i)	0.956 (c)	0.900 (i)	0.984 (i)
Tx	0.900 (c)	0.952 (i)	0.900 (c)	1.000
E	0.971 (i)	0.943 (c)	0.958 (i)	0.993 (c)
Enhanced V_{b1} (pu)	--	1.002	--	1.020

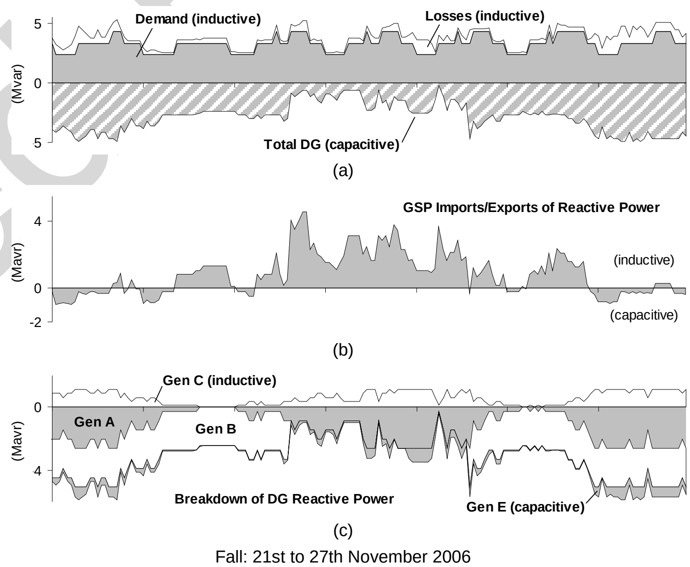

Fig. 8. EPO Approach: (a) Breakdown of the imports of reactive power (inductive/capacitive behavior) into demand, losses and the reactive requirements of generation units. (b) Imports of reactive power. (c) Breakdown of the total reactive power requirements (inductive/capacitive behavior) for each generation unit.

D. Smart Grid Control Schemes

With the Smart Grid-like control schemes presented in subsection II.B, generators' power factors and the target voltage at the substation are all expected to adapt such that the reactive power needs of the network are minimized across the year, whilst also considering N-1 constraints. Such flexibility means that at every period power factor and voltage settings will be tuned accordingly, making it possible, at least in principle, to achieve results better than the EPO approach.

The net annual Gvarh imports from the BAU, EPO (pf+V) and Smart Grid cases are shown in Fig. 9 (all cases considering N-1 constraints). Compared to the BAU case, the implementation of Smart Grid control schemes lead to an impressive reduction of 97%. As expected, the Smart Grid approach is able to achieve even lower net imports than the EPO, reducing the 3.2-Gvarh figure by more than 30%.

The time-series of the reactive power requirements of the network for the Smart Grid approach is depicted in Fig. 10 for the same week. Despite resource variability, the ability to fine tune the power factor and voltage settings allows the reactive power from the generation units to balance the inductive behavior of the demand and losses most of the time (Fig. 10-a). This results in zero varh imports/exports for many periods (in fact more than 80% of the time during the studied year). The net inductive behavior occurs when the combined DG reactive capability is smaller than that of the demand and losses (Fig. 10-b). The variability of the reactive power injection from the generation units due to their adaptive power factor behavior can also be seen in Fig. 10-c. Differently from the EPO approach (Fig. 8-c), the participation of each generator largely depends on the demand and the available generation (whilst respecting voltage, thermal and N-1 constraints). This is clearly shown during the first day: Gen B has a ‘reduced’ contribution of reactive power, allowing Gen C and the other generators to ‘step in’ and contribute accordingly.

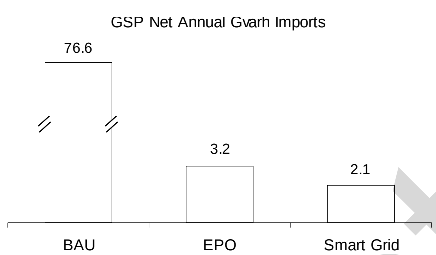

Fig. 9. Net annual Gvarh imports resulting from the business as usual (BAU), enhanced passive operation (EPO, pf+V) and Smart Grid cases all considering N-1 constraints.

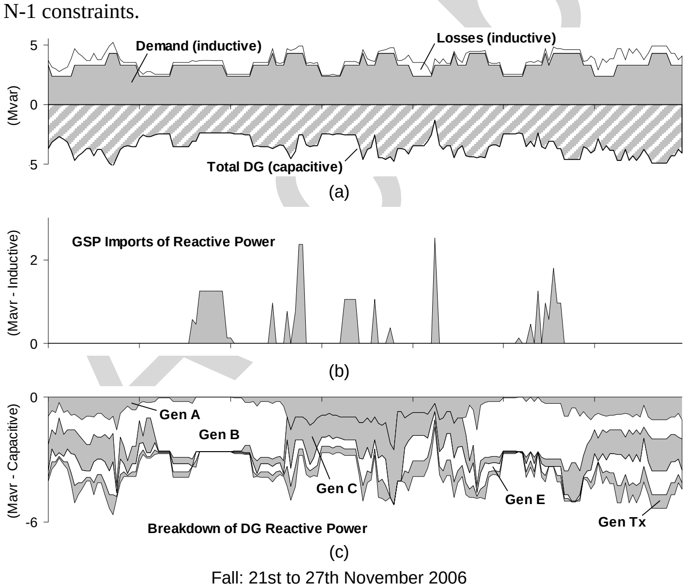

Fig. 10. Smart Grid Approach: (a) Breakdown of the imports of reactive power (inductive/capacitive behavior) into demand, losses and the reactive requirements of generation units. (b) Breakdown of the total reactive power requirements (inductive/capacitive behavior) for each generation unit. (c) Imports of reactive power.

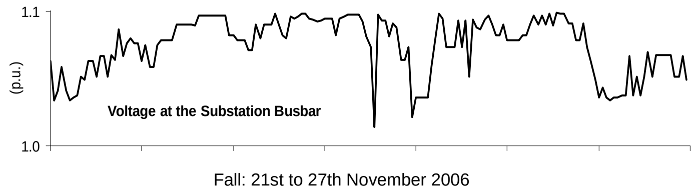

Fig. 11. Smart Grid Approach: Voltage (p.u.) at the substation busbar.

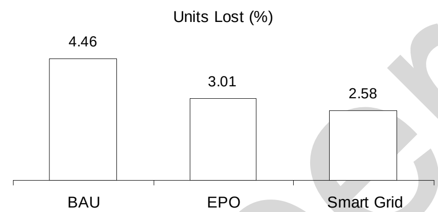

Fig. 12. Units lost resulting from the business as usual (BAU), enhanced passive operation (EPO, pf+V) and Smart Grid cases all considering N-1 constraints.

The resulting coordinated target voltage at the substation busbar is shown in Fig. 11. As it was also the case for the EPO approach, the substation voltage is a critical component in making the Smart Grid approach highly flexible.

A side benefit of minimizing the reactive power consumption from the transmission grid is the reduction of energy losses. Fig. 12 shows the energy losses as a percentage of the energy delivered to the demand, for the BAU, EPO and Smart Grid cases. The full EPO scheme (pf+V case with N-1 contingencies), is able to reduce BAU losses by 32%. This figure goes up to 42% for the Smart Grid approach. Nonetheless, it is important to highlight that the impact on energy losses and its interaction with distributed generation will mainly depend on the economic and technical objectives of the network operator and the corresponding regulatory framework [22].

It is clear that the Smart Grid approach brings about significant benefits towards reducing the reactive requirements of the distribution network. However, as demonstrated here, the majority of those benefits are not far beyond that delivered by the EPO approach. In fact, the perceived low-risk, low-cost nature of the EPO makes it an ideal interim (if not permanent) measure that can be implemented without the need for new infrastructure. It will be crucial, however, to have in place adequate regulatory and/or commercial mechanisms to encourage its adoption by DG owners.

V. Discussion

This work has demonstrated that in the particular case where (variable) distributed generation units are used to decrease the reactive power import needs of distribution networks, it is possible for the relatively simple Enhanced Passive Operation approach to achieve performance comparable with complex Smart Grid schemes. However, it has to be understood that appropriately implemented Smart Grids will not necessarily be solely devoted to a single specific purpose, such as reactive power minimization, where active control of voltage and power factor settings are required. For instance, Smart Grid schemes enable the network to swiftly adapt to unexpected contingencies (also known as self-healing networks). These and many other envisaged characteristics of future Smart Grids should be taken into account when comparing them with other alternatives. Consequently, the EPO approach and similar techniques can be considered as transitional schemes that allow better distribution network performance without the capital investment in further infrastructure.

It is worth mentioning that the use of different power factor settings would lead to different pre-fault currents and voltages, potentially requiring adjustment of the protection settings. In the examples shown, however, it is assumed that the protection system settings adequately cater for the new generator modes. This aspect is clearly an area for future work.

The technique can also be further expanded to cater for other contingencies, such as the loss of a generator. This can be achieved by including multiple generator configurations in a similar fashion to the N-1 security constraint, e.g. [21]. The EPO approach can also be adapted for seasonal power factor settings, as it is done in Spain [6]. In this case, instead of a year analysis, the periods have to be divided seasonally and the corresponding settings calculated. However, only marginal improvements are to be expected.

VI. Conclusions

The aggregate reactive power required from generators operating mostly at inductive power factors combined with the (weak) var support capability of the local transmission grid might result in operational difficulties. Here, this problem was explored by examining the ability of distributed generation to provide reactive capability. Two operational perspectives were investigated: adopting fixed but enhanced power factor and substation settings, and implementing Smart Grid control schemes. These two approaches are modeled using a tailored multi-period AC Optimal Power Flow technique that caters for the variability of demand and generation, and considers N-1 contingencies.

The first approach (Enhanced Passive Operation, EPO), demonstrated potential for minimizing reactive power through the adoption of better settings. The Smart Grid approach, as expected, outperformed this approach but not substantially. When considering the cost, effort and risk associated with implementing Smart Grid controls, the low-risk, low-cost nature of the EPO makes it an ideal interim (if not permanent) measure that can be implemented without the need for new infrastructure.

VII. Acknowledgement

The authors would like to thank John Scott (KEMA Consulting) and David Harrison (E.ON UK Central Networks) for useful discussions related to this work.

VIII. Appendix: Analytical Data

Table A-I presents the number of aggregated hours (H) for each of the considered 198 periods characterized by different loading and generation levels for demand (D), wind generation (W1 and W2) and biomass (B). Data used in [3] was adapted in order to better characterize worst case scenarios. Thus, wind generation above 0.98pu and biomass generation above 0.7pu were converted to 1.00pu. The load factor and the capacity factor of the wind 1 profile resulted in an error below 1%. Capacity factors of wind 2 and the biomass profiles carried an error of 3 and 5%, respectively. The relatively large error of the biomass was due to the 'on and off' modeling of the source.

TABLE A-I. MULTI-PERIODS - DEMAND AND GENERATION SCENARIOS

	D	W1	W2	B	H		D	W1	W2	B	H		D	W1	W2	B	H
1	0.37	0	0	0	2	67	0.5	0.7	0.9	1	65	133	0.7	0.9	0.1	1	4
	0.37	0	0	1	15		0.5	0.7	1	1	5		0.7	0.9	0.3	0	1
3	0.37	0	0.1	1	1	69	0.5	0.9	0.1	1	1	135	0.7	0.9	0.3	1	11
	0.37	0.1	0	0	1		0.5	0.9	0.3	0	1		0.7	0.9	0.5	0	10
5	0.37	0.1	0	1	6	71	0.5	0.9	0.3	1	12	137	0.7	0.9	0.5	1	62
	0.37	0.1	0.1	0	5		0.5	0.9	0.5	0	6		0.7	0.9	0.7	0	39
7	0.37	0.1	0.1	1	29	73	0.5	0.9	0.5	1	36	139	0.7	0.9	0.7	1	211
	0.37	0.1	0.3	1	1		0.5	0.9	0.7	0	21		0.7	0.9	0.9	0	73
9	0.37	0.1	0.5	1	1	75	0.5	0.9	0.7	1	149	141	0.7	0.9	0.9	1	530
	0.37	0.3	0.1	1	13		0.5	0.9	0.9	0	40		0.7	0.9	1	0	3
11	0.37	0.3	0.3	1	5	77	0.5	0.9	0.9	1	284	143	0.7	0.9	1	1	14
	0.37	0.3	0.5	1	2		0.5	0.9	1	0	3		0.7	1	0	0	1
13	0.37	0.5	0.3	1	1	79	0.5	0.9	1	1	1	145	0.7	1	0.5	1	1
	0.37	0.5	0.5	1	2		0.5	1	0.7	0	1		0.7	1	0.7	1	1
15	0.37	0.5	0.7	1	1	81	0.5	1	0.9	1	8	147	0.7	1	0.9	0	1
	0.37	0.7	0.3	1	1		0.7	0	0	0	55		0.7	1	0.9	1	10
17	0.37	0.7	0.5	1	1	83	0.7	0	0	1	463	149	0.9	0	0	0	11
	0.37	0.7	0.9	1	7		0.7	0	0.1	0	5		0.9	0	0	1	46
19	0.37	0.9	0.7	1	5	85	0.7	0	0.1	1	65	151	0.9	0	0.1	0	1
	0.37	0.9	0.9	1	2		0.7	0	0.3	1	1		0.9	0	0.1	1	12
21	0.5	0	0	0	22	87	0.7	0	0.5	1	1	153	0.9	0.1	0	1	12
	0.5	0	0	1	429		0.7	0.1	0	0	22		0.9	0.1	0.1	0	31
23	0.5	0	0.1	0	6	89	0.7	0.1	0	1	130	155	0.9	0.1	0.1	1	152
	0.5	0	0.1	1	44		0.7	0.1	0.1	0	107		0.9	0.1	0.3	0	3
25	0.5	0	0.5	1	1	91	0.7	0.1	0.1	1	800	157	0.9	0.1	0.3	1	14
	0.5	0.1	0	0	13		0.7	0.1	0.3	0	4		0.9	0.1	0.5	1	2
27	0.5	0.1	0	1	87	93	0.7	0.1	0.3	1	70	159	0.9	0.1	0.9	0	1
	0.5	0.1	0.1	0	60		0.7	0.1	0.5	0	1		0.9	0.3	0.1	0	8
29	0.5	0.1	0.1	1	690	95	0.7	0.1	0.5	1	11	161	0.9	0.3	0.1	1	57
	0.5	0.1	0.3	0	1		0.7	0.1	0.7	1	5		0.9	0.3	0.3	0	6
31	0.5	0.1	0.3	1	46	97	0.7	0.1	0.9	1	1	163	0.9	0.3	0.3	1	49
	0.5	0.1	0.5	0	1		0.7	0.3	0	0	1		0.9	0.3	0.5	1	13
33	0.5	0.1	0.5	1	9	99	0.7	0.3	0	1	8	165	0.9	0.3	0.7	1	3
	0.5	0.1	0.7	1	3		0.7	0.3	0.1	0	24		0.9	0.3	0.9	1	1
35	0.5	0.1	0.9	1	3	101	0.7	0.3	0.1	1	243	167	0.9	0.5	0.1	0	1
	0.5	0.3	0	1	6		0.7	0.3	0.3	0	36		0.9	0.5	0.1	1	12
37	0.5	0.3	0.1	0	16	103	0.7	0.3	0.3	1	312	169	0.9	0.5	0.3	0	3
	0.5	0.3	0.1	1	169		0.7	0.3	0.5	0	4		0.9	0.5	0.3	1	45
39	0.5	0.3	0.3	0	14	105	0.7	0.3	0.5	1	60	171	0.9	0.5	0.5	0	1
	0.5	0.3	0.3	1	220		0.7	0.3	0.7	0	5		0.9	0.5	0.5	1	27
41	0.5	0.3	0.5	0	1	107	0.7	0.3	0.7	1	9	173	0.9	0.5	0.7	0	1
	0.5	0.3	0.5	1	54		0.7	0.3	0.9	1	4		0.9	0.5	0.7	1	12
43	0.5	0.3	0.7	0	2	109	0.7	0.5	0	1	1	175	0.9	0.5	0.9	1	4
	0.5	0.3	0.7	1	9		0.7	0.5	0.1	0	10		0.9	0.7	0	0	1
45	0.5	0.3	0.9	1	3	111	0.7	0.5	0.1	1	36	177	0.9	0.7	0.1	0	2
	0.5	0.5	0	1	4		0.7	0.5	0.3	0	17		0.9	0.7	0.1	1	1
47	0.5	0.5	0.1	0	5	113	0.7	0.5	0.3	1	226	179	0.9	0.7	0.3	0	1
	0.5	0.5	0.1	1	42		0.7	0.5	0.5	0	17		0.9	0.7	0.3	1	16
49	0.5	0.5	0.3	0	15	115	0.7	0.5	0.5	1	185	181	0.9	0.7	0.5	0	4
	0.5	0.5	0.3	1	141		0.7	0.5	0.7	0	2		0.9	0.7	0.5	1	30
51	0.5	0.5	0.5	0	5	117	0.7	0.5	0.7	1	69	183	0.9	0.7	0.7	0	2
	0.5	0.5	0.5	1	108		0.7	0.5	0.9	1	16		0.9	0.7	0.7	1	32
53	0.5	0.5	0.7	0	3	119	0.7	0.7	0	0	1	185	0.9	0.7	0.9	1	20
	0.5	0.5	0.7	1	46		0.7	0.7	0	1	7		0.9	0.9	0	0	1
55	0.5	0.5	0.9	0	2	121	0.7	0.7	0.1	1	5	187	0.9	0.9	0	1	4
	0.5	0.5	0.9	1	10		0.7	0.7	0.3	0	6		0.9	0.9	0.1	0	1
57	0.5	0.7	0	1	4	123	0.7	0.7	0.3	1	52	189	0.9	0.9	0.1	1	1
	0.5	0.7	0.1	0	1		0.7	0.7	0.5	0	22		0.9	0.9	0.3	0	1
59	0.5	0.7	0.1	1	11	125	0.7	0.7	0.5	1	185	191	0.9	0.9	0.3	1	3
	0.5	0.7	0.3	0	4		0.7	0.7	0.7	0	15		0.9	0.9	0.5	0	1
61	0.5	0.7	0.3	1	32	127	0.7	0.7	0.7	1	133	193	0.9	0.9	0.5	1	28
	0.5	0.7	0.5	0	10		0.7	0.7	0.9	0	8		0.9	0.9	0.7	0	13
63	0.5	0.7	0.5	1	100	129	0.7	0.7	0.9	1	63	195	0.9	0.9	0.7	1	91
	0.5	0.7	0.7	0	8		0.7	0.7	1	1	3		0.9	0.9	0.9	0	10
65	0.5	0.7	0.7	1	95	131	0.7	0.9	0	0	2	197	0.9	0.9	0.9	1	167
	0.5	0.7	0.9	0	6		0.7	0.9	0	1	6		1	0.7	0.7	1	1

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