Strategic Distribution Network Planning with Smart Grid Technologies

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***Abstract*— this paper presents a multiyear distribution network planning optimization model for managing the operation and capacity of distribution systems with significant penetration of Distributed Generation (DG). The model considers investment in both traditional network and smart grid technologies including Dynamic Line Rating (DLR), Quadrature-Booster (QB), and Active Network Management (ANM) while optimizing the settings of network control devices and, if necessary, the curtailment of DG output taking into account its network access arrangement (firm or non-firm). A set of studies on a 33 kV real distribution network in the UK has been carried out to test the model. The main objective of the studies is to evaluate and compare the performance of different investment approaches, i.e. incremental and strategic investment. The studies also demonstrate the ability of the model to determine the optimal DG connection points to reduce the overall system cost. The results of the studies are discussed in this paper.**

***Index Terms*—Optimal Power Flow, distribution network planning, smart grid**

I. Nomenclature

A. Constants

Bbr_i	susceptance of the i^{th} branch
$CapacityL^S_{i,t}$	seasonal capacity of line *i* in the t^{th} operating condition (MVA)
$CapacityL^D_{i,t}$	dynamic capacity of line *i* in the t^{th} operating condition (MVA)
$CapacityTr_i$	capacity of transformer *i* (MVA)
$DLRcandidate$	set of overhead lines which are potential for new DLR installation
$EndYr$	final year of planning horizon
$endYr_{ep}$	last year of ep^{th} epoch
Gbr_i	conductance of the i^{th} branch
K_y	coefficient factor to bring the cost to present value from year y
$QBcandidate$	set of potential new Quadrature Boosters
NDG	set of DG with non-firm access
$StrYr_{ep}$	the start year of ep^{th} epoch
$SVCcandidate$	set of buses which are potential for new SVC installation
$Tcandidate$	set of potential new transformers
Th	set of operating conditions
Δ	delta matrix of the network
$\pi^{Tr}_{i,ep}$	annuitized cost of reinforcing transformer *i* in the ep^{th} epoch, (£/MVA.yr)
π^{QB}_{ep}	annuitized cost of installing a QB in ep^{th} epoch (£/MVA.yr)
$\pi^{VL}_{i,ep}$	annuitized variable cost of reinforcing line *i* in the ep^{th} epoch (£/MVA.yr)
$\pi^{fixL}_{i,ep}$	fixed cost of reinforcing line *i* in ep^{th} epoch (£)
π^{DLR}_{ep}	annuitized cost of installing DLR in the ep^{th} epoch (£/yr)
$\pi^{SVC}_{i,ep}$	annuitized cost of installing SVC at bus *i* in ep^{th} epoch, (£/Mvar.yr)
$\pi^{fixCon}_{i,j,ep}$	fixed cost of connecting DG *i* to its j^{th} candidate point in the ep^{th} epoch (£)
$\pi^{VarCon}_{i,j,ep}$	variable cost of connecting DG *i* to its j^{th} candidate point in the ep^{th} epoch (£/MVA.yr)
π^{ec}_y	cost of generation curtailment in the y^{th} year (£/MWh)
$\tau(t)$	duration of the t^{th} operating conditions (hours)
y	The number of compounding periods between the reference year and the year of the epoch in question

B. Functions

C^{Tr}_{ep}	cost of new transformers in the ep^{th} epoch (£)
C^{QB}_{ep}	cost of new Quadrature Boosters in the ep^{th} epoch (£)
C^{DLR}_{ep}	cost of new DLR installation in the ep^{th} epoch (£)
C^{line}_{ep}	cost of new lines reinforcement in the ep^{th} epoch (£)
C^{svc}_{ep}	cost of new SVCs installation in the ep^{th} epoch (£)
Cap_{QB_i}	capacity of QB installed in series with line *i* (MVA)
$Cost^{DGcur}_{ep}$	total DG curtailment cost in the ep^{th} epoch (£)
$Cost^{DGcon}_{ep}$	total DG connection cost in the ep^{th} epoch (£)
$C_{Curt_{ep}}$	costs of the total energy curtailment of non-firm DG or newly added DG

C. Variables

$B^{DLR}_{i,ep}$	decision variable to install DLR at line *i* in the ep^{th} epoch (binary)
$deltacap_{i,t}$	difference between dynamic and static capacity of line *i* in the t^{th} operating condition
$F^L_{i,ep}$	decision variable to reinforce line *i* (binary)

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$L_{i,ep}$ additional capacity for line i in the ep^{th} epoch (MVA)

$P_{i,t,ep}^{max}$ maximum output of DG_i in the t^{th} operating condition in the ep^{th} epoch (MW)

$P_{gen_{i,t,y}}$ active power output of DG_i in the t^{th} operating condition of year y in the ep^{th} epoch (MW)

$Q_{svc_{i,ep}}$ SVC installed capacity at bus i in the ep^{th} epoch (MVar)

$QB_{i,ep}$ decision variable to install a QB in series with line i in the ep^{th} epoch (binary)

$QBtap_{i,j,t,y}$ the phase shifter angle of the QB which connects between bus i and j at time t and year y (rad)

$Tr_{i,ep}$ additional capacity for transformer i in the ep^{th} epoch (MVA)

$S_{i,j}$ unit commitment of generator i in operating condition j

II. Introduction

High penetration of Distributed Generation (DG), driven by the increasing investment in low carbon generation, often triggers network reinforcement. The "fit and forget" approach to network investment, arising from generation connection, leads to suboptimal solutions, causing overinvestment in networks with high connection costs but low utilization[1]. In addition, these higher costs and/or the uncertainty of future connection costs can make the financial risk of generation investment unattractive to developers. Instead of reinforcing the network using only traditional network solutions, alternative lower-cost solutions have been explored. These solutions use new smart technologies and control techniques to provide flexibility and release latent network capacity that has not been historically accessible. Some examples, which have been put into practice [2], include Active Network Management (ANM), Dynamic Line Rating (DLR) Quadrature Boosters (QBs) (known as phase shifters), Static VAr Compensators (SVCs), and novel protection systems which improve reverse power flow.

In contrast to the "fit and forget" approach, ANM requires closer interaction between network planning, commercial network access, generation connection arrangements, and real-time network operation. ANM allows the network operator to limit the generator's export when the network is constrained. Applying ANM has the mutual benefit of allowing additional embedded generation to be connected while minimizing major network reinforcement.

The application of ANM and other smart grid technologies requires new distribution network planning tools. Determining the least-cost network design while optimizing the real-time network control requires models which are able to balance operational costs and investment costs. With the applications of smart technologies, the spectrum of investment possibilities increases significantly. The distribution network planners will require information about the timing, location, and type of investment, as well as the settings of the control devices, in order to plan their networks in an optimal way.

Pilo et al [3] describes the broad challenges faced in modern distribution network planning and provides an overview of the up-to-date solution methodologies which involve traditional and heuristic optimization approaches. Other comprehensive reviews can also be found in [4]-**Error! Reference source not found.**. A range of control strategies has also been investigated to optimize distribution network investment, for example by controlling demand [5], voltage control [7], storage **Error! Reference source not found.**, DLR [8], QB[10] and DG[10][[12]. For network operation, ANM concept [13]**Error! Reference source not found.** is used to control those active devices. The feasibility of this concept has been demonstrated in practice [14].

Other groups of studies focus on the new commercial arrangements between DG customers and the network operator needed for the ANM concept [16] which provides alternative to the traditional firm access. In general, cost benefit analysis is used to determine the trade-off between investment and smart operation, e.g. purchasing services from DG or demand customers [17]. In addition, reliability aspect has also been taken into account [18]. As the investment decisions have to be evaluated across a number of years, multiyear formulations are implemented [18][19].

While the short-term benefits of ANM have been demonstrated, the trade-off between the investment in ANM, smart technologies, and traditional network solutions in the long term has not yet been fully investigated. This is because deferring reinforcement may not be a long-term solution and, at some point, the networks will have to be reinforced if the need for new capacity increases. The results of **Error! Reference source not found.** demonstrate that best practice is to allow all investment options including both smart technologies and the traditional network reinforcement to be considered, so that the overall cost across the multi-year time horizon is minimized. This can be challenging under current regulation, e.g. in the UK, which requires that distribution network companies offer the 'minimum cost' scheme to the customers based on relatively short-term incremental investment approach unless strategic investment that enables economies of scale and leads to more sustainably and economically efficient network while maintaining appropriate levels of security of supply has been explicitly agreed with the regulator.

Therefore, the objective of this paper is to demonstrate the trade-off between smart technologies, commercial solutions, and traditional network solutions to enable better integration of new DG taking into account long-term development of distribution networks. For this purpose, a multiyear distribution network planning problem has been formulated and solved. This uses an AC Optimal Power Flow (OPF) algorithm to optimize the network reinforcement plan while maximizing the use of existing assets and actively managing the real-time operation of the network. The objective function balances the cost of network investment with the reduction in operating cost.

Unlike many existing models, which consider limited types of technologies for network reinforcement, this paper considers both the traditional reinforcement options, such as upgrading the capacity of transformers, cables and overhead lines, as well as smart solutions, including DLR, SVC and

QBs. As well as the investment options, ANM of DG output, transformer tap setting and SVC settings are optimized in the model to manage thermal and voltage constraints. The model also makes decisions about DG connection points when there is more than one option available to reduce the overall system cost in the long term. The multiyear distribution network planning problem was solved using two different planning approaches to compare their relative performance. These are referred to as strategic and incremental approaches.

Once developed, the model was tested using actual distribution network data. Unlike most planning models, which only consider two extreme operating conditions (min gen max load, max gen min load), the model considers hundreds of different operating conditions for each year. Each of the operating conditions is a unique combination of load, wind speed and seasonal temperature to cover a wide range of possible operational conditions in the real network. The modelling of uncertainty in demand and output of variable generation has also been reported in [18] and [20]. The model is also designed to support the network planners in developing new commercial agreements with DG owners, allowing non-firm access while returning the benefits of cheaper network access to the DG operators, thus reducing network reinforcement costs and increasing overall DG carrying capacity for the distribution system operators.

The structure of the paper is as follows. Section III describes the problem formulation and section IV presents the solution methodology. The case studies and the results are discussed and analyzed in section V. Section VI summarizes the contribution and the conclusions of the work.

III. Problem Formulation

A multiyear distribution network problem has been formulated to determine the least-cost plan for new capacity and voltage management of a distribution network for a predetermined future scenario. The cost function of the optimization problem consists of the summation of capital costs (network reinforcement costs, DG connection costs) and operational costs (DG curtailment costs, cost of load-shedding). As the problem involves costs incurred in different years, the present value approach is used to enable costs to be evaluated in a consistent way.

Each planning period, referred to as an epoch, consists of a few years. Each year has many operating conditions with different combinations of load and wind profiles and seasonal temperatures This is explained in more detail in section V.. For each epoch in the model, all investments occur at the beginning of the respective epoch.

The cost function for each epoch is:

$$Cost_{ep} = Cost_{ep}^{Re} + Cost_{ep}^{DGcon} + Cost_{ep}^{DGcur} + Cost_{ep}^{Lshed} \quad (1)$$

The reinforcement cost per epoch can be obtained as the summation of the different terms described as follows:

$$Cost_{ep}^{Re} = C_{ep}^{Tr} + C_{ep}^{QB} + C_{ep}^{DLR} + C_{ep}^{line} + C_{ep}^{svc} \quad (2)$$

The transformer investment cost can be expressed as:

$$C_{ep}^{Tr} = \sum_{y=StrYr_{ep}}^{EndYr} \sum_{\mathrm{i\in Tcandidate}} K_y \, Tr_{i,ep} \, \pi_{i,ep}^{Tr} \quad (3)$$

$$K_y = \frac{1}{(1+discount\ rate)^y} \quad (4)$$

The quadrature booster investment cost can be expressed as:

$$C_{ep}^{QB} = \sum_{y=StrYr_{ep}}^{EndYr} \sum_{\mathrm{i\in QBcandidate}} K_y \, QB_{i,ep} Cap_{QB_i} \pi_{ep}^{QB} \quad (5)$$

The $QB_{i,ep}$ is the decision binary variable for installing a new QB at line *i* in epoch *ep*. The capacity of the QB should be the same as the capacity of the related line as the QB is installed in series with lines.

The DLR investment cost can be expressed as:

$$C_{ep}^{DLR} = \sum_{y=StrYr_{ep}}^{EndYr} \sum_{\mathrm{i\in DLRcandidate}} K_y \, B_{i,ep}^{DLR} \, \pi_{ep}^{DLR} \quad (6)$$

The DLR decision variable $B_{i,ep}^{DLR}$ is also a binary variable.

The line reinforcement cost can be expressed as:

$$C_{ep}^{line} = \sum_{y=StrYr_{ep}}^{EndYr} \left(\sum_{\mathrm{i\in Lcandidate}} K_y \, L_{i,ep} \, \pi_{i,ep}^{VL}\right) + \sum_{i\in Lcandidate} F_{i,ep}^{L} \, \pi_{i,ep}^{fixL} \quad (7)$$

Line reinforcement cost consists of two terms: a fixed cost and a variable cost. The variable cost depends on the amount of added capacity. Different fixed costs are applied to different corridors depending on the length of the corridors. $F_{i,ep}^{L}$ is a binary decision variable associated with the reinforcement of line *i* in epoch *ep*.

The SVC investment cost can be expressed as:

$$C_{ep}^{svc} = \sum_{y=StrYr_{ep}}^{EndYr} \sum_{i\in SVCcandidate} K_y \, Q_{svc_{i,ep}} \, \pi_{i,ep}^{svc} \quad (8)$$

The connection cost of a new DG is expressed as:

$$Cost_{ep}^{DGcon} = \sum_{i\in DG_{ep}^{new}} \Big[\sum_{j\in ConSet_i} D_{i,j} \, \pi_{i,j,ep}^{fixCon} + \sum_{y=StrYr_{ep}}^{EndYr} \Big(\sum_{j\in ConSet_i} K_y \, D_{i,j} \, \pi_{i,j,ep}^{VarCon}\Big)\Big] \quad (9)$$

DG_{ep}^{new} is a set of new DG which are going to be connected to the network in epoch *ep*. For each new DG ($Newdg_i$), there is a set of candidate entry points for grid connection ($ConSet_i$). $D_{i,j}$ is a binary decision variable which shows whether or not $Newdg_i$ will be connected to the j^{th} candidate of connection points.

The DG curtailment cost can be expressed as:

$$Cost_{ep}^{DGcur} = C\_Curt_{ep}^{Non-firm\ DG} + C\_Curt_{ep}^{new\ DG} \quad (10)$$

$C\_Curt_{ep}^{Non-firm\ DG}$ and $C\_Curt_{ep}^{new\ DG}$ are the costs of the total energy curtailment of non-firm DG and newly added DG.

$$C_{Curt_{ep}}^{Non-firm\ DG} = \sum_{y=Stryr_{ep}}^{endYr_{ep}} k_y \times \sum_{i\in NDG} \sum_{t\in Th} [\pi_y^{ec} \times \tau(t) \times (P_{i,t,ep}^{max} - P_{gen_{i,t,y}})] \quad (11)$$

$$C\_Curt_{ep}^{new\ DG} = \sum_{y=Stryr_{ep}}^{endYr_{ep}} k_y \times \sum_{i\in DG_{ep}^{new}} \sum_{t\in Th} [\pi_y^{ec} \times \tau(t) \times (P_{i,t,ep}^{max} - \sum_{j\in ConSet_i} P_{gen_{j,t,y}})] \quad (12)$$

$$\forall j \in ConSet_i \quad 0 \le Pgen_{j,t,y} \le S_{i,j} \times P_{i,t,ep}^{max} \tag{13}$$

$$\sum_{j \in ConSet_i} S_{i,j} = 1 \tag{14}$$

$$S_{i,j} \le D_{i,j} \tag{15}$$

To avoid complexity in the model, the binary decision variable $D_{i,j}$ is not used in (13). Instead a continuous variable $(S_{i,j})$ is used which is related to $D_{i,j}$ in (15). Equations (14) and (15) guarantee that one and only one of the DG in candidate connection points will have the same capacity as DG_i and the rest have zero capacity.

A. *Modeling of smart technologies*

1) QB Modeling

The following equations are used to model the QB in the power flow formulation [25].The equations show the real and reactive flow through line *i* which is between bus *a* and *b*.

$$P_{a,b} =$$

$$V_a{}^2 \times \mathrm{Gbr_i} - V_a V_b \times [Gbr_i \cos(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b}) +$$

$$Bbr_i \sin(\delta_{a,} - \delta_b + I_i^{QB} \times QBtap_{a,b})] \tag{16}$$

$$Q_{a,b} =$$

$$-V_a{}^2 \times \mathrm{Bbr_i} - V_a V_b \times [Gbr_i \sin(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b}) -$$

$$Bbr_i \cos(\delta_a - \delta_b + I_i^{QB} \times QBtap_{a,b})] \tag{17}$$

$\mathrm{I_i^{QB}}$ is a binary variable which indicates if a QB is installed at line i.

2) DLR Modelling

The thermal capacity of overhead lines can be calculated by many different methods [22]-**Error! Reference source not found.**. Based on the IEEE Std 738-2006 [22] for an overhead line, considering the maximum permissible temperature of the conductor, thermal ampacity will be obtained as follows:

$$I^2 R(T_c) + q_s = q_c + q_r \tag{18}$$

q_r and q_s are radiative cooling and solar heating. Convective cooling (q_c) is made of two forces: natural and forced. Natural convection q_{cn} depends on the conductor temperature, ambient temperature, overall diameter of the conductor and the air density.

$$q_{cn} = 0.0205 \rho_f{}^{0.5} D^{0.75} (T_C - T_a)^{1.25} \tag{19}$$

Forced convection is the cooling provided by wind. There are two types of forced convection, one for low wind speeds and another for high wind speeds. Referring to IEEE standard, the larger value of the natural and the two forced convection components is used.

$$q_{clow} = [1.01 + 0.0372 \left(\frac{D\rho_f V_w}{\mu_f}\right)^{0.52}] k_f K_{angle} (T_c - T_{a)} \tag{20}$$

$$q_{chigh} = [0.0119 \left(\frac{D\rho_f V_w}{\mu_f}\right)^{0.6}] k_f K_{angle} (T_c - T_{a)} \tag{21}$$

To include the impact of DLR on the ampacity of overhead lines in this study, the ambient temperature and wind speed in (20) and (21) are recorded for different conditions. With a different convective cooling value in every operating condition $\mathrm{deltacap_{i,t}}$ is calculated for the overhead line i at condition (t). $\mathrm{deltacap_{i,t}}$ is the difference between the static seasonal capacity of line i and its dynamic line capacity at condition t.

$$deltacap_{i,t} = CapacityL_{i,t}^D - CapacityL_{i,t}^S \tag{22}$$

Equations (26) and (27) are the thermal constraints for overhead lines taking into account the increased capacity enabled by DLR.

B. *Network Constraints*

The problem has the following constraints.

1) Generators limits

$$i \in firm\ DGs \qquad Pgen_{i,t,y} = P_{i,t,ep}^{max} \tag{23}$$

$$i \in nonfirmDGs \quad P_{i,t,ep}^{min} \le Pgen_{i,t,y} \le P_{i,t,ep}^{max} \tag{24}$$

2) Voltage constraints: voltages of buses should remain in security limits in all time

$$\forall i \in Nbus \qquad \underline{V} \le V_{i,t,y} \le \bar{V} \tag{25}$$

3) Thermal constraints:

- Lines

$$\forall i \in NLines$$
$$P_{i,t,y}{}^2 + Q_{i,t,y}{}^2 \le \left(CapacityL_{i,t}^S + DLR_{i,ep} \times deltacap_i + \sum_{s=1}^{ep} L_{i,s}\right)^2 \tag{26}$$

$$0 \le DLR_{i,ep} \le B_{i,ep}^{DLR} \tag{27}$$

To avoid complexity in the model, the binary decision variable $B_{i,ep}^{DLR}$ is not used in (26). Instead, to model the impact of DLR, a continuous variable $DLR_{i,ep}$ is used which is related to $B_{i,ep}^{DLR}$ in (27).

- Transformers

$$\forall i \in NTrans$$

$$P_{i,t,y}{}^2 + Q_{i,t,y}{}^2 \le (CapacityTr_i + \sum_{s=1}^{ep} Tr_{i,ep})^2 \tag{28}$$

IV. Solution Method

The cost function in (1) is the cost of the ep^{th} epoch. There are two different approaches for solving the multi-epoch planning problem: *incremental planning* and *strategic planning*.

In the incremental approach, planning is started from the initial network (epoch 0) and the OPF is run to find the least cost feasible solution for epoch 1. The solution of epoch 1 is used as the initial network for solving the problem in epoch 2, and the process is repeated until all epochs have been evaluated. The objective function of the distribution network planning optimization problem for each epoch with the incremental approach can be expressed as:

$$\forall ep \in 1..N_{ep} \qquad Minimize \quad Cost_{ep} \tag{29}$$

Then the total cost is the sum of the cost per epoch.

In the strategic approach, planning is done for all epochs simultaneously. This approach results in the least cost plan for the entire planning period. The strategic approach can be expressed as:

$$Minimize\ \sum_{i\in 1}^{N_{ep}} Cost_{\ ep} \tag{30}$$

The optimization problem described here is formulated as a mixed-integer non-linear problem, solved using the commercial optimization software FICO Xpress [24]. It is well known that the global solution may not be always found for this type of complex problems (discrete and non-linear) unless we exploit the solution space using heuristic approaches. However, in practice, the solution will provide some guidance to the network planner on the direction of the optimal solution. At this stage, the performance of the model is sufficient to meet the objective of the paper.

V. Case Studies

A. Description

The methodology proposed has been tested on a real 33 kV distribution network with 29 buses and 36 branches, as shown in Fig.1. The network was derived from the real distribution network in UK near Cambridge area **Error! Reference source not found.**. This area of the network is connected to the upstream network via two connection points, bus 2 and bus 27, via 132/33 kV transformers. Power can be exported to or imported from the upstream network at both connection points. The network is also connected to the downstream 11 kV network via five 33/11 kV primary substations. Each of these substations has two 33/11 kV transformers. The network has 7 load buses that are connected at both 33 kV and 11 kV levels. The peak demand is 101 MW and a uniform power factor of 0.98 is assumed to apply to all loads.

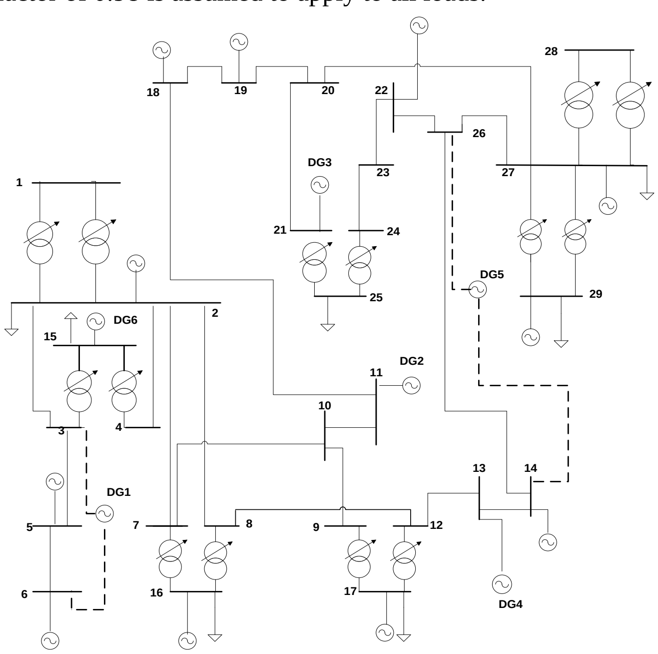

Fig. 1. Network diagram

The system has 11 DG (wind farms), with a total generation capacity of 160 MW. The planning horizon is 16 years, divided into 4 epochs of equal duration (4 years). This represents 2 distribution price control periods in the UK, which was changed on 1 April 2015 from 5 years to 8 years per period. During this planning horizon, new DGs (wind farms) are to be connected. The projected plan for DG connection is as follows:

- DG 1 at bus 6 or bus 3: 7.5 MW at 1st epoch,
- DG 2 at bus 11: 6 MW at 1st epoch, another 4 MW at 2nd epoch
- DG 3 at bus 21: 17.5 MW at 1st epoch
- DG 4 at bus 13: 10 MW at 2nd epoch, another 2 MW at 3rd epoch
- DG 5 at bus 14 or bus 26: 6 MW at 2nd epoch, another 4 MW at 3rd epoch
- DG 6 at bus 15: 5 MW at 4th epoch

The load profile remains the same for all the loads in all four epochs. This assumes that the load growth has been offset by increased energy efficiency and that net load growth is negligible, except for the load at bus 25 which will increase by 20% from the second epoch onwards as a result of a new connection. This is a scenario used to create a case where the network reinforcement is driven only by new DG connection, except for bus 25.

In this model as the objective function makes a balance between the investment cost and the operating cost of the network and the investment cost is compared to the operating cost, it is very important to profile a wide range of possible operating conditions of the network and have the duration of each of the profiles. Here, each year is divided into 300 different operating conditions with a unique combination of load and wind profiles and seasonal ambient temperature (spring/autumn, summer and winter). The duration of each operating condition may not be the same; the sum of duration of all credible operating conditions in a year is equal to 8760 hours.

Each operating condition is characterized with demand level (d), wind output profile (w) and seasonal temperature and it has a share of $\tau(t)$ hours in a year. The characteristic load profiles and wind profiles have be derived from year round hourly profiles. 10 different demand levels and 10 different wind outputs have been considered. In each season ten different demand levels have been defined and then a probability density function (pdf) of wind output has been defined for each demand level. This procedure is done for three different seasons (3x10x10). The same approach is found in [18].

B. Network constraints:

Before connecting the new DGs, the system is sufficient to integrate all DGs with no curtailment, i.e. a passive network. After connecting new DGs, some voltage and thermal constraints will be present in the network, which could result in DG curtailment if no reinforcement is planned to overcome the problems.

The first constrained area is between bus 2 and bus 6. When DG1 is connected to bus 6, the voltages at buses 5 and 6 will reach the highest statutory limit and lines L3-5 (a line connecting bus 3 and bus 5) and L2-3 will reach their thermal limits in some of the operating conditions, especially when demand is low during high wind conditions. For DG1, the initial connection offer is at bus 6, with a 7 km long circuit from the DG1. There is an alternative connection point for this DG on bus 3 with a 10 km circuit length.

The second constrained asset is the line connecting buses 10 and 11. Connecting DG2 to bus 11 will overload L 7-10 and L10-11. To prevent the overloading of these two lines, the output of DG2 should be curtailed in some of the conditions.

The third constrained asset is bus 25. DG3 will cause unacceptable voltage rise at this bus. As a consequence, the output of DG3 needs to be curtailed in a number of operating conditions.

The last constrained asset is the line connecting buses 13 and 14. Connecting DG4 will increase the flow through L8-12 and L12-13. To prevent the overloading of these lines, the outputs of DG4 and DG5 are curtailed in some operating conditions, especially during high wind conditions. For DG5, the initial connection offer is to connect at bus 14 with 3 km long line from the DG. There is also an alternative connection point for this DG, at bus 26, with 5 km circuit length.

C. Case studies

The proposed optimization model has been applied to the problem descried here. There are six case studies with different planning options and solution approaches. Tables A.1 and A.2 in Appendix show the reinforcement costs used in the study.The simulation studies were carried out using a HP Z800 workstation with double 3.3 GHz processors and 192 GB RAM, and the solution time was in the range of few hours. It is important to highlight as the studies can be classified as planning studies, this magnitude of computation time is not critical.

In order to demonstrate the effectiveness of smart solutions, and the advantages of having non-firm connection for DGs, the planning is applied to four different cases with different planning options. The first four studies are solved using the incremental approach. In the fifth case study, case study 1 is repeated, this time with the strategic approach to identify the difference between the incremental and the strategic planning. In these five case studies the initial connection offers for the new DG are used. In the last case study the model also optimizes the connection points of DG1 and DG5 with the strategic approach. Table 1 shows the list of case studies and the planning options for each.

TABLE I
CASE STUDIES DESCRIPTION

case study	investment approach	smart assets	traditional assets	DG curtailment	alternative DG connection point
1	incremental	✓	✓	✓	
2	incremental		✓	✓	
3	incremental	✓	✓		
4	incremental			✓	
5	strategic	✓	✓	✓	
6	strategic	✓	✓	✓	✓

Table 2 shows the summary of the results for the 6 case studies. The costs represent the net present value of investment costs and DG curtailment over the 16 year planning horizon. The connection cost in the table indicates only the connection costs of DG1 and DG5. As the other 4 DGs have no alternative connection points, their connection costs are not included in the model's cost function as the model does not optimize their connection points. Table 3 shows the details of planning and production from DG in cases 1, 5 and 6. The results for case 2 and 3, and the costs of different planning options are presented in Table A.3 in the Appendix.

TABLE II.
PLANNING COSTS IN 6 CASE STUDIES

case study	investment cost (£)		DG curtailment (%)	DG curtailment cost (£)	connection cost (£)	Total planning cost (£)
	smart	traditional				
1	1,297,076	681,951	0.49%	426,424	488,866	2,894,317
2	0	6,622,828	4%	3,321,277	488,866	10,432,971
3	1,464,181	1,503,509	0%	0	488,866	3,456,556
4	0	0	18%	10,684,834	488,866	11,173,700
5	1,177,261	615,248	0.36%	300,158	488,866	2,581,533
6	1,139,496	146,947	0.34%	283,519	726,697	2,296,659

1) Case study 1:

In the first epoch, DG1 is connected to bus 6 with 7.5 MW of capacity. A new SVC is proposed to be installed at bus 6 to minimize the voltage driven DG curtailment due to the voltage rise effect. The connection of DG1 will result in 7.5 MW of additional loading on L3-5 and L2-3. In this epoch, L3-5 has almost reached its nominal capacity in the initial network so it needs to be reinforced by implementing DLR. The dynamic rating of L3-5 is sufficient for accommodating extra generation from bus 6 to 5.

TABLE III
THE PLANNING RESULTS IN CASE STUDY 1, 5 AND 6

Case study	1		5		6	
Epoch	Item	Amount	Item	Amount	Item	Amount
epoch 1	SVC B6	3.6 Mvar	SVC B6	3.6 Mvar	SVC B6	2.9 Mvar
	SVC B25	1 Mvar	DLR L3-5		QB L11-18	18.69 MVA
	DLR L3-5		QB L11-18	18.69 MVA	DG 1	848 MWh
	DG 1	887 MWh	DG 1	1437 MWh	DG 3	542 MWh
	DG 2	2189 MWh	DG 3	391 MWh		
	DG 3	966 MWh				
epoch 2	Rei* L8-12	6.6 MVA	Rei L12-13	14.6 MVA	DLR L12-13	
	DLR L12-13		Rei L8-12	11 MVA	DLR L26-17	
	QB L11-18	18.69 MVA	DG 1	755 MWh	DG 1	881 MWh
	DG 1	809 MWh	DG 4	61 MWh	DG 4	21 MWh
	DG 4	852 MWh				
epoch 3	Rei L8-12	5.1 MVA	DG 1	784 MWh	DG 1	881 MWh
	Rei L12-13	5.7 MVA	DG 4	1231 MWh	DG 3	482 MWh
	DG 1	758 MWh			DG 4	873 MWh
	DG 4	859 MWh				
epoch 4	Rei L2-3	2.5 MVA	Rei L2-3	2.5 MVA	Rei L2-3	2.5 MVA
	DG 1	781 MWh	DG	945 MWh	DG 1	803 MWh
	DG 4	858 MWh	DG	1229 MWh	DG 2	317 MWh
	DG 6	432 MWh	DG	163 MWh	DG 3	108 MWh
					DG 4	927 MWh

* "Rei" refers to reinforcement

Also in the first epoch, DG2 is planned to be connected to bus 11. DG2 will be connected to the network via two circuits, L10-11 and L11-18. L10-11 reaches its maximum loading limit when DG2 is connected, as the flow direction is from bus 11 towards bus 10. DG2 output will be curtailed under some operating conditions. However, the volume of curtailment is not significant enough to trigger the need for network reinforcement.

In the second epoch, the capacity of DG2 increases to 10 MW. As L10-11 is already overloaded, a QB is installed at L11-18 to achieve optimal load sharing between L10-11 and L11-18. This allows for export of extra generation from DG2. If the QB is not an option in the reinforcement plan, connecting DG2 to bus 11 will result in reinforcing L7-10 and L10-11, which results in higher cost. The direction of flow in this part of the network is from bus 18 to 11 via L11-18, from bus 11 to 10 and from bus 10 to 7. Installing a QB at L11-18 can control the flow through this line and decrease the flow toward bus 11 in high wind conditions, preventing L10-11 from being overloaded. Therefore, with the QB, the network can integrate DG2 without any additional reinforcement. Fig. 2 shows the utilization of L11-18, L10-11and DG2 output power in 6 operating conditions. It shows that when the output of DG2 increases and L10-11 reaches its maximum capacity the flow through L11-18 decreases with QB to avoid L10-11 of being overload or DG2 of being curtailed.

In the second epoch, 10 MW DG4 and 6 MW DG5 are connected to buses 13 and 14. Their connection increases flows through constrained lines L12-13 and L8-12. L12-13 is an overhead line and so using a DLR can increase its capacity by up to 60%. L8-12 is an underground cable and it will be reinforced for an additional 6.6 MW of capacity. DG4 will still be curtailed in some conditions due to the thermal limits of these two lines.

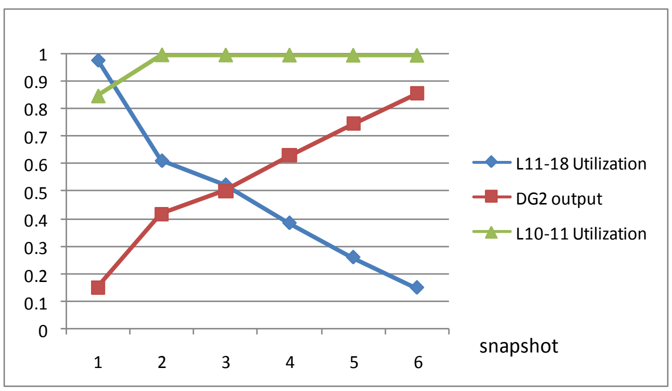

Fig. 2. Application of QB in controlling the flow through L11-18

In the third epoch, the capacity of DG5 increases by 4 MW and more capacity is needed in L8-12 and L12-13. Although L12-13 is equipped with DLR, more capacity is needed than its dynamic rating and, therefore, it is upgraded by 5.7 MW in the third epoch.

In the last epoch, L2-3 is reinforced. By connecting DG6 to bus 15, a part of the load at bus 15 will be supplied locally and a greater share of the DG generation from buses 5 and 6 will flow through L2-3 towards bus 2. This line has already reached its maximum capacity and so it shall be reinforced to avoid more DG curtailment.

2) Case study 2

When smart assets are not included as planning options, the SVC cannot be used to solve the voltage rise in the grid. Therefore, a new DG cannot be connected to the grid unless the extra generation will be exported to the upstream network to avoid voltage rise. In this case 132/33kV transformers have to be reinforced to increase the reverse power capacity from the 33kV network to the 132 kV network. As expected, the investment cost increases almost 3.6 times relative to the first case study where the use of smart solutions is considered as an option.

3) Case study 3

Both the smart and traditional reinforcement options are considered in the planning options but the newly added DG requires firm access to the grid and, therefore, DG curtailment is not an option. The total cost has increased by 19% and the investment cost has increased by 143% compared to case 1. The huge increase in the investment cost is due to the avoidance of curtailment of new DG as observed in the case study 1 when DG has non-firm access. This demonstrates that providing only firm access for DG can be an expensive option.

4) Case study 4

If there is no reinforcement of the grid, 18% of new DG generation capacity will be curtailed due to active voltage and thermal constraints in the network.

5) Case study 5

The total planning cost with the strategic approach is 11% less than the cost with the incremental approach. This reduction in cost is expected as the strategic approach finds the optimal solution for the whole study horizon, while the incremental approach finds the optimal solution for each epoch. Therefore the incremental approach does not necessarily result in the optimum solution for the whole planning horizon. With the strategic approach, investment in the QB is brought forward from epoch 2 to epoch 1 so it may prevent the curtailment of DGs 2 and 3 in the first epoch as well and therefore reduces the total planning costs. The 1 Mvar SVC at bus 25, in the incremental planning results, is not proposed in the case with the strategic approach. As the load in bus 25 increases in the second epoch there would be no need for a SVC, except for in the first epoch. Therefore, with strategic planning, it is not worth installing a SVC only for one epoch. In the second epoch, L8-12 and L12-13 are reinforced. Although DLR is an available option for L12-13, and its dynamic rating is sufficient for the second epoch, when considering the whole planning horizon, the DLR effect is not enough and traditional reinforcement would be needed as well. There is greater benefit from reinforcing the line in the first place and therefore avoiding further investment at a later date.

L8-12 is reinforced only once and for 11 MW in the second epoch. This is to avoid paying the fixed cost twice as it is observed in the case with the incremental approach. The rest of the plan is the same as the results of the case study 1.

6) Case study 6

The alternative connection points have been chosen for both DGs 1 and 5. Although the alternative points involve longer circuits, and therefore higher costs, they will result in a cheaper plan when the curtailment and the system reinforcement costs of the network are considered. The total cost of case 6 is 89% of the total cost in case 5 (Table 2) although the connection cost has increased by 50% in case 6 compared to case 5.

Even before connecting DG1, the voltage at bus 6 has already reached its maximum limit in high wind profiles. In case study 1, when DG1 was connected to bus 6, a 3.6 Mvar SVC is installed at this bus to control the voltage and to prevent the DG curtailment. When DG1 is connected to bus 3, a SVC is still required at bus 6 to control the voltage but the capacity of the SVC is less, i.e. 2.9 Mvar, and also the curtailment of DG1 decreases as compared to the previous case. The curtailment of DG1 at bus 3 is 87% of its curtailment when it is connected to bus 6. The other difference between the two cases is that there is no need for reinforcing L3-5 by DLR as DG1 is connected to bus 3 and its generation will not flow through L3-5.

When DG5 is connected to bus 26 instead of bus 14, there would be no need to upgrade the capacity of L8-12 and L12-13. Dynamic rating of L12-13 will be enough to integrate the generation of DG4 at bus 13, and L8-12 does not need extra capacity. In this case L26-27 will be equipped with DLR as it has already reached its maximum capacity before connecting DG5 at bus 26. The curtailment of DG4 is 72% of its curtailment in case study 5.

VI. Conclusion

This paper demonstrates an approach that can be used to determine the optimal long-term development strategy for a distribution network, when considering traditional network reinforcement, smart grid technologies and commercial solutions. The developed methodology has been successfully tested on a real distribution network. It has been demonstrated that the proposed methodology encourages the use of active network management to optimize utilization of the existing network capacity and also increases the capacity of the network when required.

Two different investment strategies – incremental and strategic investment – have ben used to solve the multi-year planning problem. The incremental approach tends to overuse smart solutions, with the aim of deferring network reinforcement cost. This results in lower short-term costs but, in the end, the long-term costs are higher. On the other hand, the strategic investment approach optimizes the overall costs so that the long-term costs are minimized, but may result in higher short-term costs. For the future work, the model will be further developed to enable risk assessment considering the uncertainty in future system development and used to study the option value of smartgrid technologies which can provide flexibility for dealing with future uncertainty. Other improvement of the model will include security assessment which takes into account the contribution of DG to system security and improvement of the efficiency of the formulation in order to reduce the computation time and improve the overall performance.

VII. Appendix

1) Cost of Network Reinforcement

The reinforcement cost for 33 kV Over Head (OH) Line and Underground Cables (UC) are as follows:

Table A.1
The reinforcement cost for 33 kV Over Head (OH) Line

Cross section (mm^2)	OH			
	R (Ohm/km)	X (Ohm/km)	Capacity (MVA)	Reinforcement Price (£/MW/km)
95	0.398	0.400	13.430	3,946
185	0.205	0.360	19.140	2,769
300	0.126	0.340	24.860	2,132
630	0.060	0.280	43.440	1,220
1000	0.038	0.210	49.156	1,078

Table A.2.
The reinforcement cost for 33 kV Underground Cables

Cross section (mm^2)	UG			
	R (Ohm/km)	X (Ohm/km)	Capacity (MVA)	Reinforcement Price (£/MW/km)
95	0.398	0.127	13.430	25,838
185	0.205	0.114	19.140	18,130
300	0.126	0.105	24.860	13,958
630	0.060	0.094	43.440	7,988
1000	0.038	0.087	49.156	7,059

Investment cost of QB is £2,500/MVA/year and the cost of SVC is assumed £15/kVAr/year.

2) Results of case study no 2 and 3.

Table A.3
Results of case study no 2 and 3

Case study	2		3	
Epoch	Item	Amount	Item	Amount
epoch 1	Rei L3-5	4.3 MVA	Rei L2-3	2.5 MVA
	Rei L7-10	8 MVA	Rei L12-13	
	Rei L8-12	8 MVA	QB L11-18	18.69 MVA
	Rei L10-11	11 MVA	SVC Bus6	4Mvar
	Rei L12-13	10 MVA	SVC Bus1	1 Mvar
	Rei T1-2	10 MVA		
	DG1	4695MWh		
	DG3	8586 MWh		
epoch 2	Rei L7-10	2.7 MVA	Rei L8-12	12.3 MVA
	Rei L8-12	5.9 MVA	Rei L12-13	13.7 MVA
	Rei L10-11	3.5 MVA		
	Rei L12-13	6.1 MVA		
	Rei T1-2	8 MVA		
	DG1	3521 MWh		
	DG3	14764 MWh		
epoch 3	DG1	4302 MWh	Rei L2-3	5.9 MVA
	DG3	20 MWh	Rei L8-12	10 MVA
	DG5	18137 MWh	DLR L12-13	
epoch 4	Rei L12-13	1 MVA	Rei L2-3	3 MVA
	Rei T1-2	3.3 MVA	SVC Bus5	1 Mvar
	DG1	5781 MWh	SVC Bus29	1Mvar
	DG2	18067 MWh		
	DG5	23 MWh		

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