Optimal Integration of RES-based DGs with Reactive Power Support Capabilities in Distribution Network Systems

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***Abstract*—One of the major changes currently involving distribution network systems (DNSs) is the ever-increasing integration of renewable-based distributed generation (DG), wind and solar PV types in particular. This is dramatically influencing the planning and operation of distribution systems, in general. The traditional "fit-and-forget" approach is outdated. Current developments in the DNS would require new, efficient and robust planning and operation tools to support smooth integration of such DGs. The present work focuses on an optimal integration of renewable-based DGs with reactive power support capabilities. Accordingly, a stochastic mixed integer linear programming (S-MILP) model is developed that takes into account the optimal integration of RES-based DGs and reactive power sources. The developed model is tested using a standard IEEE distribution system. Test results show that integrating DGs with reactive power support capability significantly enhances voltage stability and improves the overall cost in the system. Simulation results show that setting the reactive power support capability of the RES-based DGs from 0.95 leading to 0.95 lagging leads to the maximum penetration level of wind and solar PV power in the system.**

***Index Terms*--distributed generation, distribution network, optimal integration, reactive power support, renewable energy sources.**

I. NOMENCLATURE

A. Sets/Indices

c/Ω^c	Index/set of capacitor banks
i/Ω^i	Index/set of buses
$g/\Omega^g/\Omega^{DG}$	Index/set of generators/DGs
k/Ω^k	Index/set of branches
s/Ω^s	Index/set of scenarios
t/Ω^t	Index/set of planning stages
w/Ω^w	Index/set of snapshots
$\varsigma/\Omega^\varsigma$	Index/set of substations

B. Parameters

$ER_g^N, ER_g^E, ER_\varsigma^{SS}$	Emission rates of new and existing DGs, and energy purchased, respectively (tCO2e/MWh)
g_k, b_k, S_k^{max}	Conductance, susceptance and flow limit k
$IC_{g,i}, IC_k, IC_{c,i}$	Investment cost of DG, line and capacitor banks, respectively (M€)
L	Total number of linear segments
LT_g, LT_k, LT_c	Lifetimes of DG, line, energy storage system and capacitor banks, respectively (years)
MC_c	Maintenance cost of capacitor bank per year (M€)
MC_g^N, MC_g^E	Maintenance costs of new and existing DGs (M€/yr)
MC_k^N, MC_k^E	Maintenance cost of new and existing line (M€/yr)
MP_k, MQ_k	Big-M parameters associated to active and reactive power flows through branch k, respectively
N_i, N_ς	Number of buses and substations, respectively
$OC_{g,i,s,w,t}^N, OC_{g,i,s,w,t}^E$	Operation cost of unit energy production by new and existing DGs (€/MWh)
Q_c^0	Rating of minimum capacitor bank (MVAr)
V_{nom}	Nominal voltage (kV)
α_l, β_l	Slopes of linear segments
$\lambda_{s,w,t}^{CO_2e}$	Price of emissions (€/tons of CO_2 equivalent)
$\lambda_{s,w,t}^{\varsigma}$	Price of electricity purchased (€/MWh)
ρ_s, π_w	Probability of scenario s and weight (in hours) of snapshot group w
$\upsilon_{s,w,t}$	Penalty for unserved power (€/MW)

C. Variables

$\delta_{i,s,w,t}$	Unserved power at node i
$D_{s,w,t}^i, Q_{s,w,t}^i$	Active and reactive power demand at node i
$P_{g,i,s,w,t}^N, P_{g,i,s,w,t}^E$	Active power produced by new and existing DGs
$P_{\varsigma,s,w,t}^{SS}, Q_{\varsigma,s,w,t}^{SS}$	Active and reactive power imported from grid
P_k, Q_k, θ_k	Active and reactive power flows, and voltage angle difference of link k, respectively
$p_{k,s,w,t,l}, q_{k,s,w,t,l}$	Step variables used in linearization of quadratic flows
PL_k, QL_k	Active and reactive power losses, respectively
$PL_{\varsigma,s,w,t}, QL_{\varsigma,s,w,t}$	Active and reactive losses at substation ς
$Q_{i,s,w,t}^c$	Reactive power injected by capacitor bank at node i
$Q_{g,i,s,w,t}^N, Q_{g,i,s,w,t}^E$	Reactive power provided by new and existing DGs
$u_{g,i,t}, u_{k,t}$	Utilization variables of existing DG and lines
$x_{g,i,t}, x_{c,i,t}, x_{k,t}$	Investment variables for DG, capacitor banks and distribution lines

D. Functions

EC_t^{SS}	Expected cost of energy purchased from upstream
$ENSC_t$	Expected cost of unserved power
$EmiC_t^{DG}$	Expected emission cost of DG power production
$EmiC_t^N, EmiC_t^E$	Expected emission cost of power production using new and existing DGs, respectively
$EmiC_t^{SS}$	Expected emission cost of purchased power
$InvC_t^{CAP}, MntC_t^{Cap}$	NPV investment/maintenance cost of capacitor banks
$InvC_t^{DG}, MntC_t^{DG}, EC_t^{DG}$	NPV investment/maintenance/expected energy cost of DGs, respectively
$InvC_t^{LN}, MntC_t^{LN}$	NPV investment/maintenance cost of a line

II. Introduction

A. Aims and Motivations

Increasing demand for electricity, environmental and climate change concerns are triggering a policy shift all over the world, especially when it comes to electric power production. Policy makers of various nations have been introducing targets to achieve large-scale integration of "clean" electric energy sources, and consequently, reduce the heavy dependence on fossil fuels for energy production. Moreover, the recent developments in a climate change conference held in Paris (COP21) are expected to further accelerate renewable integration in many electric distribution network systems (DNSs). Because of all this, appropriately designed planning tools are required to support an optimal integration of such resources. In other words, the dynamic and optimal placement and sizing of DGs in distribution systems is becoming extremely important in both technical and economic terms. This is especially relevant with DGs based on renewable energy sources (RESs) because of their inherently intermittent nature, which introduce significant uncertainty and variability as well as many technical problems to the system [1]. These are some of the issues that limit the level of integration of such DGs.

This is partly due to the fact that most of the conventional wind and solar type DGs "consume" reactive power or mostly operate at a unity power factor. This makes large-scale integration of such DGs more challenging because of the resulting technical issues unless this is done in coordination with different smart-grid enabling technologies such as reactive power sources, energy storage systems, advanced network switching systems, etc. In addition to such coordination, all DGs need to satisfy various criteria and grid codes set by the regulatory body and/or network operator. In this regard, reactive power support capability is among the "mandatory" grid code requirements, which has been predominantly fulfilled by conventional power plants. However, this is very likely to change in the future; renewable DGs will also be required to produce and absorb reactive power, when needed. Taking this into consideration, the present work aims to develop a coordinated and dynamic stochastic planning tool for optimal integration of reactive power sources, renewable-based DGs with reactive power support capabilities and network reinforcements in DNSs. To this end, a stochastic mixed integer linear programming (S-MILP) model is developed, employing a linearized AC model.

B. Literature Review

The DG placement and sizing subject have attracted special interest from researchers in recent years. An excellent review of previous works related to this subject area, published prior to the year 2013, is presented in [2]. In [2] and [3], an analysis of several techniques used on the impact assessment of DG in the electrical system is presented. Most of these techniques analyze the distribution system to determine rules that can be used for DG integration [4]. Important issues related to the connection of DG units are the network topology, DG capacity and suitable location; because, each bus in the system has an optimal level of DG integration; otherwise, system losses may increase [5].

Recently, several methods have been proposed for planning and operation or in some cases for both location and sizing of DGs in distribution systems. In general, these methods can be classified as heuristic [6]–[12], numerical [13]–[16] and analytical [13] based methods. Heuristic methods apply advanced artificial intelligence algorithms, such as genetic algorithms (GA) [6], [7], particle swarm optimization (PSO) [7]–[9], harmony search (HS) [10], [11] and big bang crunch (BBC) [12]. Numerical methods are algorithms that seek numerical solution to a given problem. Some of the most recent works use nonlinear mixed integer programming (MINLP) [13], mixed integer linear programming (MILP) [14], [15], and AC optimal power flow (OPF)-based [16] methods for solving the aforementioned problem.

Analytical methods are based on the search for the optimal DG location for a given DG size under different load models. Therefore, these methods fail to represent accurately the behavior of the DG optimization problem involving two decision variables, both for optimum DG size and optimal DG location. In [17], authors present a technique with a probabilistic basis for determining the capacity and optimal placement of wind DG units to minimize energy losses in distribution systems.

Many of the previous works in the literature on areas related to the DG placement and sizing problem only consider the optimal location of a single DG unit, mostly of conventional DGs. The simultaneous consideration of placement, timing and sizing of DG units (especially RESs with reactive power capabilities), along with the placement, timing and sizing of reactive power sources, seems to be far from being addressed in the literature. In connection to this, the increase in RES-based DG penetration increases the uncertainty and the fluctuations of the system production. If the placement and proper sizing is not taken into account, the benefits of DG integration may not be exploited; instead, this may result in the degradation of system efficiency, increased cost of electricity and energy losses.

C. Contributions

The main contributions of this work are threefold:

- A multi-stage and stochastic optimization model, which simultaneously considers the integration of reactive power sources, renewable DGs with reactive power support capabilities and network reinforcements;
- The use of a linearized AC network model for the analysis, which captures well the inherent characteristics of electric networks, and balances accuracy with computational burden;
- An extensive analysis related to the impact of enforcing reactive power support capability in renewable type DGs on the RES integration level, system cost and losses.

D. Paper Organization

The rest of this paper is organized as follows. Section III presents a brief description of the developed mathematical model. Numerical results are discussed in Section IV. The final section, Section V, concludes this paper.

III. Problem Formulation

As mentioned earlier, this work develops an integrated optimization model that simultaneously finds the optimal placement and sizing DGs (particularly, focusing on wind and solar) and reactive power sources such as capacitor banks. The entire model is formulated as an S-MILP optimization. In addition, instead of the customary direct current (DC) network models, a linearized AC model is used here to better capture the inherent characteristics of the network system.

A. Objective Function

The problem is formulated as a multi-objective stochastic MILP with an objective of overall cost minimization as in (1). The objective function in (1) is composed of Net Present Value (NPV) of five cost terms each weighted by a certain relevance factor $\alpha_j; \forall j \in \{1,2,\dots,5\}$. Note that, in this work, all cost terms are assumed to be equally important; hence, these factors are set to 1. However, depending on the relative importance of the considered costs, different weights can be adopted in the objective function. The first term in (1), $TInvC$, represents the total investment costs under the assumption of perpetual planning horizon [18]. In other words, "the investment cost is amortized in annual installments throughout the lifetime of the installed component", as is done in [19].

Here, the total investment cost is the sum of investment costs of new and existing DGs, feeders and capacitor banks, as in (2). And, this cost is computed as in (7)-(9).

The second term, TMC, in (1) denotes the total maintenance costs, which is given by the sum of individual maintenance costs of new and existing DGs as well as that of feeders and capacitor banks in the system at each stage and the corresponding costs incurred after the last planning stage, as in (3). Note that the latter depend on the maintenance costs of the last planning stage. A perpetual planning horizon is also assumed here. The individual maintenance costs are computed according to Eqs. (10)-(12).

The third term TEC in (1) refers to the total cost of energy in the system, which is the sum of the cost of power produced by new and existing DGs, and purchased from upstream at each stage as in (4). Eq. (4) also includes the total energy costs incurred after the last planning stage under the assumption of perpetual planning horizon. These depend on the energy costs of the last planning stage. The detailed mathematical expressions for computing the cost of DG energy and that of purchased power are given in (13) and (14), respectively. The fourth term $TENSC$ represents the total cost of unserved power in the system, given as in (5). And, this is computed using (15). The last term $TEmiC$ gathers the total emission costs in the system, given by the sum of emission costs for the existing (17) and new DGs as well that of purchased power (18).

$$Minimize\ TC = \alpha_1 * TInvC + \alpha_2 * TMC + \alpha_3 * TEC + \alpha_4 * TENSC + \alpha_5 * TImiC \quad (1)$$

$$TInvC = \underbrace{\textstyle\sum_{t\epsilon\Omega^t}(1+r)^{-t}(InvC_t^{DG} + InvC_t^{LN} + InvC_t^{CAP})/r}_{NPV\ of\ investment\ cost} \quad (2)$$

$$TMC = \underbrace{\textstyle\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ (MntC_t^{DG} + MntC_t^{LN} + MntC_t^{Cap})}_{NPV\ of\ maintenance\ costs} + \underbrace{(1+r)^{-T}(MntC_T^{DG} + MntC_T^{LN} + MntC_T^{Cap})/r}_{NPV\ maintenance\ costs\ incured\ after\ stage\ T} \quad (3)$$

$$TEC = \underbrace{\textstyle\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ (EC_t^{DG} + EC_t^{SS})}_{NPV\ of\ operation\ costs} + \underbrace{(1+r)^{-T}(EC_T^{DG} + EC_T^{SS})/r}_{NPV\ operation\ costs\ incured\ after\ stage\ T} \quad (4)$$

$$ENSC = \underbrace{\textstyle\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ ENSC_t}_{NPV\ of\ reliability\ costs} + \underbrace{(1+r)^{-T}ENSC_T/r}_{NPV\ reliability\ costs\ incured\ after\ stage\ T} \quad (5)$$

$$TEmiC = \underbrace{\textstyle\sum_{t\epsilon\Omega^t}(1+r)^{-t}\ (EmiC_t^{DG} + EmiC_t^{SS})}_{NPV\ emission\ costs} + \underbrace{(1+r)^{-T}(EmiC_T^{DG} + EmiC_T^{SS})/r}_{NPV\ emission\ costs\ incured\ after\ stage\ T} \quad (6)$$

$$InvC_t^{DG} = \textstyle\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}\frac{r(1+r)^{LT_g}}{(1+r)^{LT_g}-1}IC_{g,i}(x_{g,i,t} - x_{g,i,t-1})\ ;where\ x_{g,i,0} = 0 \quad (7)$$

$$InvC_t^{LN} = \textstyle\sum_{k\epsilon\Omega^\ell}\frac{r(1+r)^{LT_k}}{(1+r)^{LT_k}-1}IC_k(x_{k,t} - x_{k,t-1})\ ;\ where\ x_{k,0} = 0 \quad (8)$$

$$InvC_t^{CAP} = \textstyle\sum_{c\epsilon\Omega^c}\sum_{i\epsilon\Omega^i}\frac{r(1+r)^{LT_c}}{(1+r)^{LT_c}-1}IC_c(x_{c,i,t} - x_{c,i,t-1})\ ;where\ x_{c,i,0} = 0 \quad (9)$$

$$MntC_t^{DG} = \textstyle\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}MC_g^N\, x_{g,i,t} + \sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}MC_g^E\, u_{g,i,t} \quad (10)$$

$$MntC_t^{LN} = \textstyle\sum_{k\epsilon\Omega^{e\ell}}MC_k^E\, u_{k,t} + \sum_{k\epsilon\Omega^{n\ell}}MC_k^N x_{k,t} \quad (11)$$

$$MntC_t^{Cap} = \textstyle\sum_{c\epsilon\Omega^c}\sum_{i\epsilon\Omega^i}MC_c x_{c,i,t} \quad (12)$$

$$EC_t^{DG} = \textstyle\sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}(OC_{g,i,s,w,t}^N P_{g,i,s,w,t}^N + OC_{g,i,s,w,t}^E\, P_{g,i,s,w,t}^E) \quad (13)$$

$$EC_t^{SS} = \textstyle\sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{\varsigma,\Omega^\varsigma}\lambda_{s,w,t}^\varsigma P_{\varsigma,s,w,t}^{SS} \quad (14)$$

$$ENSC_t = \textstyle\sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\sum_{i\epsilon\Omega^i}\pi_w\upsilon_{s,w,t}\delta_{i,s,w,t} \quad (15)$$

$$EmiC_t^{DG} = EmiC_t^N + EmiC_t^E \quad (16)$$

$$EmiC_t^N = \textstyle\sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}\lambda_{s,w,t}^{CO_2e}ER_g^N P_{g,i,s,w,t}^N \quad (17)$$

$$EmiC_t^E = \textstyle\sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{g\epsilon\Omega^g}\sum_{i\epsilon\Omega^i}\lambda_{s,w,t}^{CO_2e}ER_g^E P_{g,i,s,w,t}^E \quad (18)$$

$$EmiC_t^{SS} = \textstyle\sum_{s\epsilon\Omega^s}\rho_s\sum_{w\epsilon\Omega^w}\pi_w\sum_{\varsigma\epsilon\Omega^\varsigma}\sum_{i\epsilon\Omega^i}\lambda_{s,w,t}^{CO_2e}ER_\varsigma^{SS}P_{\varsigma,s,w,t}^{SS} \quad (19)$$

B. Constraints

In the interest of problem tractability, a linearized AC network model, which was first introduced in [20] in the context of transmission expansion planning problem and further extended in [21] for distribution system planning, is employed here. Hence, the linearized active and reactive power flows in [20] and [21] are included here. The apparent power flow S_k through an existing (20) and new (21) line, given by $\sqrt{P_k^2 + Q_k^2}$, should be less than or equal to its rated value.

$$P_{k,s,w,t}^2 + Q_{k,s,w,t}^2 \le u_{k,t}(S_k^{max})^2 \quad (20)$$

$$P_{k,s,w,t}^2 + Q_{k,s,w,t}^2 \le x_{k,t}(S_k^{max})^2 \quad (21)$$

The quadratic expressions in (27) and (28) are linearized using a piecewise linearization, considering a sufficiently large number of partitions, L. Here, an incremental approach (which is based on first-order approximation of the nonlinear curve) is used because of its relatively simple formulation and easy implementation [22]. In this case, the associated linear constraints are:

$$P_{k,s,w,t}^2 \approx \textstyle\sum_{l=1}^L \alpha_{k,l}p_{k,s,w,t,l} \quad (22)$$

$$Q_{k,s,w,t}^2 \approx \textstyle\sum_{l=1}^L \beta_{k,l}q_{k,s,w,t,l} \quad (23)$$

$$P_{k,s,w,t}^+ + P_{k,s,w,t}^- = \textstyle\sum_{l=1}^L p_{k,s,w,t,l} \quad (24)$$

$$Q_{k,s,w,t}^+ + Q_{k,s,w,t}^- = \textstyle\sum_{l=1}^L q_{k,s,w,t,l} \quad (25)$$

where $p_{k,s,w,t,l} \le P_k^{max}/L$ and $q_{k,s,w,t,l} \le Q_k^{max}/L$.

The flow-based active (26) and reactive (27) power losses in line k are adopted here. The respective active and reactive power balances are enforced by:

$$PL_{k,s,w,t} = r_k(P_{k,s,w,t}^2 + Q_{k,s,w,t}^2)/(V_{nom})^2 \quad (26)$$

$$QL_{k,s,w,t} = x_k(P_{k,s,w,t}^2 + Q_{k,s,w,t}^2)/(V_{nom})^2 \quad (27)$$

$$\textstyle\sum_{g\epsilon\Omega^{DG}}(P_{g,i,s,w,t}^E + P_{g,i,s,w,t}^N) + P_{\varsigma,s,w,t}^{SS} + \sum_{in,k\epsilon i}P_{k,s,w,t} - \sum_{out,k\epsilon i}P_{k,s,w,t} + \delta_{i,s,w,t} = D_{s,w,t}^i + PL_{\varsigma,s,w,t} + \sum_{k\epsilon i}\tfrac{1}{2}PL_{k,s,w,t}\ ;\ \forall\varsigma,\forall\varsigma\epsilon i \quad (28)$$

$$\textstyle\sum_{g\epsilon\Omega^{DG}}(Q_{g,i,s,w,t}^E + Q_{g,i,s,w,t}^N) + \sum_{c\epsilon\Omega^c}Q_{i,s,w,t}^c + Q_{\varsigma,s,w,t}^{SS} + \sum_{in,k\epsilon i}Q_{k,s,w,t} - \sum_{out,k\epsilon i}Q_{k,s,w,t} = Q_{s,w,t}^i + QL_{\varsigma,s,w,t} + \sum_{in,k\epsilon i}\tfrac{1}{2}QL_{k,s,w,t} + \sum_{out,k\epsilon i}\tfrac{1}{2}QL_{k,s,w,t}\ ;\ \forall\varsigma,\forall\varsigma\epsilon i \quad (29)$$

The active and reactive capacity limits of existing generators are given by (30) and (31), respectively. In the case of new generators, the corresponding constraints are given by (32) and (33).

$$P_{g,i,s,w,t}^{E,min}u_{g,i,t} \le P_{g,i,s,w,t}^E \le P_{g,i,s,w,t}^{E,max}u_{g,i,t} \quad (30)$$

$$Q_{g,i,s,w,t}^{E,min}u_{g,i,t} \le Q_{g,i,s,w,t}^E \le Q_{g,i,s,w,t}^{E,max}u_{g,i,t} \quad (31)$$

$$P_{g,i,s,w,t}^{N,min}x_{g,i,t} \le P_{g,i,s,w,t}^N \le P_{g,i,s,w,t}^{N,max}x_{g,i,t} \quad (32)$$

$$Q_{g,i,s,w,t}^{N,min}x_{g,i,t} \le Q_{g,i,s,w,t}^N \le Q_{g,i,s,w,t}^{N,max}x_{g,i,t} \quad (33)$$

It should be noted that, for wind and solar PV generators, the upper bound $P_{g,i,s,w,t}^{max}$ should be equal to the actual power production level at a given hour, which in turn depends on the level of primary energy source (wind speed or solar radiation). And, the lower bound $P_{g,i,s,w,t}^{max}$ in this case is simply set to zero. In addition, when the problem involves wind and solar type DGs with reactive power support capabilities such as doubly fed induction generator (DFIG) based wind turbine and voltage source inverter (VSI) based PV, the following constraints are used:

$$-\tan(\cos^{-1}(pf_g)) * P_{g,i,s,w,t}^E \le Q_{g,i,s,w,t}^E \le \tan(\cos^{-1}(pf_g)) * P_{g,i,s,w,t}^E \quad (34)$$

$$-\tan\left(\cos^{-1}(pf_g)\right) * P^N_{g,i,s,w,t} \le Q^N_{g,i,s,w,t} \le \tan(\cos^{-1}(pf_g)) * P^N_{g,i,s,w,t} \quad (35)$$

The above two inequalities show that the wind and solar type DGs are capable of operating between pf_g leading power factor (capacitive) and pf_g lagging power factor (reactive). This means such DGs are capable of "producing" and "consuming" reactive power depending on operational situations in the system.

Inequality (36) ensures that the reactive power produced by the reactive power sources (capacitor banks) is bounded between zero and the maximum possible capacity. The logical constraints in (37) ensure that an investment decision already made cannot be reversed.

$$0 \le Q^c_{i,s,w,t} \le x_{c,i,t} Q^0_c \quad (36)$$

$$x_{k,t} \ge x_{k,t-1}; \quad x_{g,i,t} \ge x_{g,i,t-1}; \quad x_{c,i,t} \ge x_{c,i,t-1} \quad (37)$$

Distribution systems are normally operated radially. There are two conditions that must be fulfilled in order a DNS to be radial. First, the solution must have $N_i - N_\varsigma$ circuits. Second, the final topology should be connected. Eq. (38) represents the first necessary condition for maintaining the radial topology of DNS.

$$\textstyle\sum_{k\in\Omega^{ij}} OR(x_{k,t}, u_{k,t}) = N_i - N_\varsigma \quad ;\forall t \quad (38)$$

For the sake of simplicity, every corridor in the system is assumed to be candidate for line investment/reinforcement. Hence, in a given corridor, we can have either an existing branch or a new one, or both connected in parallel. The "OR" function in (38) takes these possible combinations into account. The nonlinearity introduced by the "OR" function is handled using the following set of linear constraints:

$$z_{k,t} \le x_{k,t} + u_{k,t};\ z_{k,t} \ge x_{k,t};\ z_{k,t} \ge u_{k,t};\ 0 \le z_{k,t} \le 1 \quad ;\forall t \quad (39)$$

Then, the radiality constraints in (38) can be reformulated as:

$$\textstyle\sum_{k\in\Omega^{ij}} z_{k,t} = N_i - N_\varsigma \quad ;\forall t \quad (40)$$

IV. Numerical Results

The radial DNS, shown in Fig. 1, is used to test the proposed planning model. Data for this system can be found in [23].

For the analysis in this paper, a 3-year planning horizon is considered, which is divided into yearly planning stages, and interest rate is set to 7%. The number of piecewise linear segments is limited to 5. This balances well accuracy with computation burden (see in [22]). Hourly snapshots in a given year (containing demand-generation patterns, electricity price profile, etc) are grouped into 200 operational snapshots via the so-called *k-means* clustering algorithm. For the sake of simplicity, all maintenance costs of components are assumed to be 2% of the corresponding investment costs. The expected lifetime of capacitor banks is assumed to be 15 years [24], while that of DGs and feeders is 25 years [19]. A maximum allowable deviation of 5% in bus voltages is considered. Node 1 is considered as a reference; hence, its voltage magnitude and angle are set to $1.05 * V_{nom}$ and 0, respectively.

The power transfer capacity of each feeder is 6.986 MVA, and all big-*M* parameters are set to 10, which is sufficiently higher than the power transfer capacity of all feeders. The investment cost of each feeder is assumed to be directly proportional to its impedance i.e. $C_{ij} = constant * Z_{ij}$ where the proportionality constant is 10,000 €/Ω.

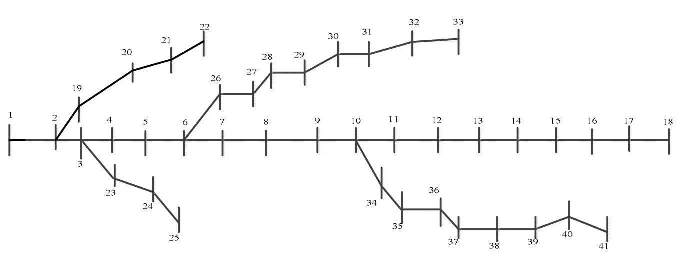

Fig. 1. Single-line diagram of the IEEE 41-bus radial DNS.

Wind and solar PV type DGs, each with a 1 MW installed capacity, are considered as potential candidates to be deployed in the system. The investment costs of these DGs are assumed to be 2.64 M€ and 3 M€, respectively [25]. Variable power generation sources (wind and solar, in particular) are assumed to be available in every node. This assumption emanates from the fact that distribution networks span over a small geographical area. Hence, the distribution of resources in this area can be considered to be the same. The size of minimum deployable capacitor bank is considered to be 0.1 MVAr. The unit cost of capacitor banks is assumed to be €25/kVAr.

To obtain appreciable investments in the system, the demand in the base case is increased by 50% to about 7 MW and 5 MVAr. In addition, yearly demand growths of 5%, 10% and 15% are considered. Emission prices in the first, second and third stages are set to 25, 45 and 60 €/tCO_2e, respectively. The emission rate of power purchased is arbitrarily set equal to 0.4 tCO_2e/MWh. The cost of unserved energy is taken to be to 3000 €/MWh. As mentioned from the outset, wind and solar PV type DGs with reactive power support capability are considered in the simulations. Examples in this case are doubly fed induction generator (DFIG) based wind turbines and voltage-source inverter (VSI) based PV generators. The power factor setting is varied to investigate its effects on selected system variables such as node voltage, losses, different costs and RES penetration level.

The profiles of average voltage deviations at each node corresponding to different power factor settings are shown in Fig. 2. One can see that there are no significant differences in these profiles, except for nodes where the distributed energy resources (DG and reactive power sources) are connected to. The differences at these nodes with changes in power factor settings can be explained by the fact that the amount of each DER installed at these nodes is different for different power factor values (see in Fig. 3). It is interesting to see from Fig. 3 that, when DGs with reactive power support capabilities are used, 45 to 48 MW DG power is installed in the considered system (which has a base case peak load of nearly 7 MW) throughout the planning horizon depending on the power factor setting.

As illustrated in Fig. 3, the size of combined wind and solar PV power installed at each node hardly varies regardless of the power factor setting as far as capacitor banks are installed to complement the required reactive power support (see Fig. 4) especially when the power factor setting is closer to unity. However, slight changes are observed in the amount of RES energy absorbed by the system for different power factor settings, which is depicted in Fig. 5. One can see in this figure that a power factor setting of about 0.95 results in the highest RES energy production compared to any other setting. It can also be seen in Fig. 6 that the overall cost (which is the sum of investment, maintenance, emission and energy costs) is the lowest at the same power factor.

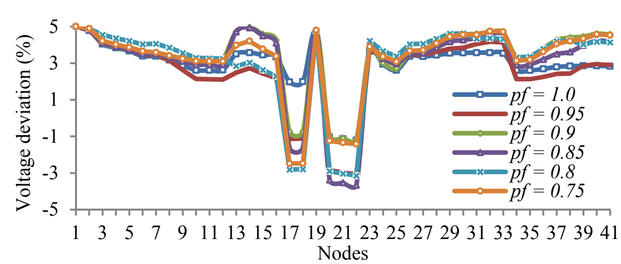

Fig. 2. Average voltage deviations at each node for different power factor values.

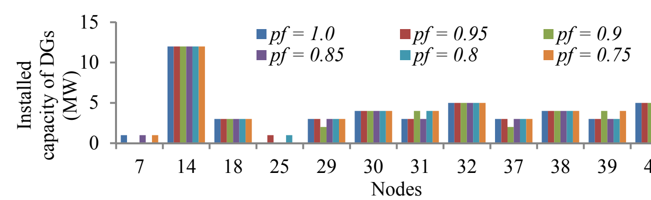

Fig. 3. Installed RES power at each node for different power factor settings.

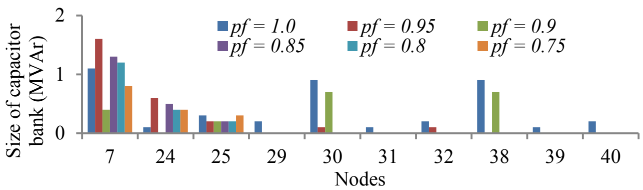

Fig. 4. Size of capacitor banks at each node and for different power factor values.

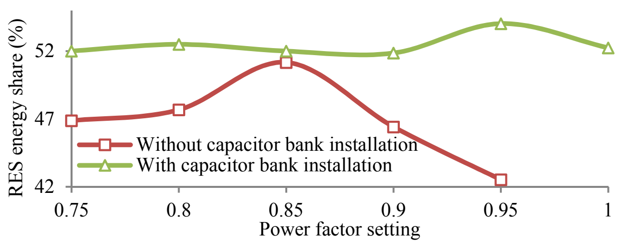

Fig. 5. Evolution of RES energy production share with varying power factor.

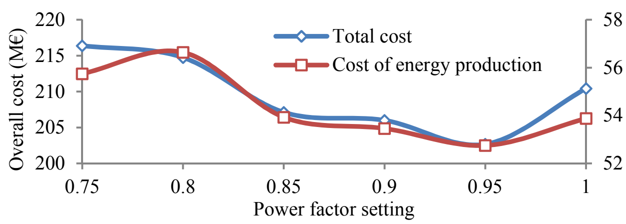

Fig. 6. Evolution of total energy and system costs with varying power factor.

Note that this is the case when reactive power sources are simultaneously deployed in the system. However, if this is not the case (i.e. without reactive power sources deployment), the optimal power factor setting is shifted to about 0.85. This is because the DGs need to partly cover the huge reactive power requirement.

V. Conclusions

This work has developed a multi-stage, multi-objective and stochastic model, employing a linearized AC network model that captures the inherent electrical characteristics of the network system. The proposed model jointly optimized the integration of distributed energy sources (particularly, focusing on RES-based DGs with reactive power support capability) along with network reinforcement needs. The standard IEEE 41-bus distribution system has been used to test the developed model and carry out the required analysis from the standpoint of the objectives set in this work. The results of the case study showed that simultaneous planning of reactive power sources and RES-based DGs with reactive power support capabilities largely enabled a substantially increased penetration of variable generation (wind and solar) in the system. In addition, significant reductions in system costs and network losses were attained, as well as in network investment needs. For the case study, more than 45 MW of DG capacity has been installed in the system within the three-years planning horizon. This can be put into perspective with the modified base-case peak load of about 7 MW. The results also showed that the optimal power factor setting for the considered DGs, which resulted in the highest penetration level of renewable power, was 0.95 when reactive power sources were jointly planned with the DGs. Generally, it has been demonstrated that the integration of RES-based DGs with reactive power support capabilities, along with reactive power sources, brings about significant improvements to the system such as reduction of losses, electricity cost and emissions, contributing also to voltage stability, which is essential for a correct system operation.

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