A Dynamic Approach for Distribution System Planning Considering Distributed Generation

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***Abstract*—Deregulation in the power system industry and invention of new technologies for producing electrical energy have led to innovations in distribution system planning (DSP). Distributed generation (DG) is one of the most attractive technologies that brings different kinds of advantages to a wide range of entities, engaged in power systems. In this paper, a new model for considering DGs in the DSP problem is presented. In this model, an optimal power flow (OPF) is proposed to minimize capital costs for network upgrading, operation and maintenance costs, and the cost of losses for handling the load growth for the planning horizon. The term "dynamic" is used to refer to the planning over a specific period so that dynamic distribution system planning is, in fact, proposed. Besides, a modified genetic algorithm is used to find the optimal topology solution. The effectiveness of this method is demonstrated through examination on a radial distribution network.**

***Index Terms*—Distributed generation (DG), distribution system planning (DSP), genetic algorithm (GA), optimal load flow (OPF).**

NOMENCLATURE

A. Indices

i, j	Bus indices.
k	Load-level index.
l	Substation bus index.
t	Time index (one year).
u	Substation transformers index.

B. Indicators

DG	Stands for distributed generation.
LB	Stands for load buses.
LL	Stands for load levels.
SS	Stands for substation.
U	Stands for substation transformers.

Manuscript received June 12, 2011; revised October 02, 2011; accepted March 31, 2012. Date of publication May 21, 2012; date of current version June 20, 2012. Paper no. TPWRD-00510-2011.

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Digital Object Identifier 10.1109/TPWRD.2012.2194744

C. Parameters

AC_{DG}	DG annual investment cost (U.S.$/MVA).
$AC_{l,u}$	Annual investment cost of transformer u installed in substation l ($).
CC	Equipment actual capital cost (U.S.$/MVA or U.S.$).
$C_{DG\ i}$	Cost of DG operation and maintenance (O&M) in (U.S.$/MWh).
C_{ij}	Total feeder reinforcement cost from bus i to j.
$C_{SS\ k}$	Electricity price for load level k in (U.S.$/MWh).
d	Discount rate.
LD_k	Duration of load level $k(h)$.
LT	Equipment lifetime (in years).
N_{LB}	Number of load buses.
N_{LL}	Number of load levels.
N_{SS}	Total number of system existing substations.
N_T	Total number of system buses.
N_U	Total number of installed transformers.
pf	System power factor.
S_{ij}^{Max}	Maximum capacity of feeder from buses i to j.
$S_{SS\ l}^{\mathrm{Max}}$	Maximum capacity of substation l.
T	Total planning years.
V_n	Nominal bus voltage (in kilovolts).
ΔV	Maximum acceptable voltage deviation (in kilovolts).
$\boldsymbol{Z_{ij}}$	Feeder impedance from bus i to j.

D. Variables

BK	Back up DG capacity (in megavolt amperes).
$\boldsymbol{I_{ij}}$	Complex value of feeder current between buses i and j in Amperes (in kiloamperes).
$IY_{DG\ i}$	Installation year of DG in bus I (independent variable).
$IY_{f,\ ij}$	Upgrading year for feeder from bus i to j (independent variable).
$IY_{l,u}$	Installation year of transformer u in substation l (independent variable).

S_{DG}^{M} DG maximum capacity (in megavolt amperes) (independent variable).

$S_{DG\ t,k,i}$ Power supplied by DG in year t, at load level k, and at bus i (in megavolt amperes).

S_{ij} Power flow in feeder from bus i to j (in megavolt amperes).

$S_{l,u}$ Power supplied by transformer u in substation l (in megavolt amperes).

$S_{SS\ l}$ Power delivered by substation l (in megavolt amperes).

V_i Voltage at bus i (in kilovolts).

β Present value conversion factor.

$\sigma_{\mathrm{DG\ i,t}}$ Decision variable that shows existence of DG at bus i in year t (independent variable).

$\sigma_{ij,\ t}$ Decision variable that shows the need for investment on feeder reinforcement between buses i and j in year t (independent variable).

$\sigma_{l,u,t}$ Decision variable which shows the existence of transformer u at substation l in year t (independent variable).

I. Introduction

DEREGULATION in the power systems industry has led to major changes in planning and operation issues in bulk electrical systems as well as in distribution systems. The main aim of these changes is to maximize the efficiency of energy usage in an electric power system. Introducing the competitive electricity markets is the first step toward reaching the efficiency in electric power consumption which may result in various entities to respond. As a consequence, electric utility distribution companies (DISCOs) are willing to meet their customers load growth in a way that captures the most economical benefits of the business, while maintaining an acceptable range of quality and reliability of supply. Therefore, DISCOs are eager to use new technologies and options for expansion plans, to reduce the cost of providing customers with a suitable power supply.

In traditional distribution systems, the flow of energy is in one direction, namely from the distribution substation transformer through distribution feeders to load-point transformers. Thus, traditional distribution systems planning (DSP) programs aim to expand a substation by installing new transformers or building new substations, as the load grows. If this additional equipment and load result in overloaded feeders, investing in reinforcement or construction of feeders may be required [1], [2]. In [3] and [4], the publications on traditional DSP strategies are reviewed.

Implementing distributed generation (DG), with many attractive economical and technical features, in medium- and low-voltage parts of the grid, is one of the alternatives to reinforce distribution systems. If DGs are properly placed in a network, some benefits, such as loss reduction, peak shaving, voltage control, ancillary services, higher power quality and reliability indices, deferral of transmission and distribution systems reinforcement, and environmental concerns may be achieved. Generally speaking, the advantages of using a DG can be summarized as follows [5]:

- short lead time and low investment risk since it is built in modules;
- small-capacity modules that can track load variation more closely;
- small physical size that can be installed at load centers and may not need government approval or search for utility territory and land availability;
- existence of a vast range of technologies [6].

On the other hand, locating DGs in a network may bring about some technical problems, such as voltage oscillations, increased fault currents, altering the power-flow direction, etc. Thus, for the installation of DG units with appropriate capacities in a grid, a large number of attributes should be considered and assessed. In DSP, as proposed in [7]–[9], the planning horizon is divided into several subperiods and the problem is solved by considering the investment and the operation costs. In [9]–[14], deferment of grid reinforcement is studied upon using DGs. A method for assessment of network capability for absorbing DG units is suggested in [15]. In [16], reliability issues are used for placement and sizing of DGs in a grid. Consideration of the tradeoff between the conflicting profits of a utility and the individual DG owners is presented in [17]. A market-based approach for allocation of DGs is proposed in [18] where the social welfare and DG owner benefits are maximized. In [19], the amount of incentives that the utility can pay to investors for DG installation is computed. In [20], the loading margin maximization and DISCO profit maximization are considered as the two objectives of the planning problem. Then, by combining these two objectives into one single function and implementing a hybrid approach of the fuzzy/genetic algorithm, the problem has been solved. In [21], the problem is considered from a microgrid owner point of view. The objective function considered is the ratio of the benefits to the costs for a microgrid owner, subject to some network constraints. A review of different aspects that could be considered in DSP is studied in [22]. In Table I, a review of recently published literature on DG integration in power systems is tabulated.

In this paper, a new dynamic DSP model is proposed that considers DG integration into a network as an option to meet the load growth in the planning horizon. In the model, the investment costs, the operation and maintenance (O&M) costs, and the power losses costs are considered as optimization objectives. Grid technical constraints, such as power balance, voltage drop, distribution substation transformers and feeder capacity limits, capacity reserve, available DG capacities, and total DG capacity penetration limit are considered. The optimal solution which is the best tradeoff between different investment alternatives is obtained by performing an optimal power flow (OPF) for each planning strategy. The load-flow method used here is a network topology-based backward-forward sweep approach [38], designed especially for radial distribution networks. The final optimum solution consists of equipment type, location, capacity, and year of installation of new facilities which are the independent variables of this problem. A year-dependent decision variable is attached to each investment alternative, enabling a dynamic planning scheme [called Dynamic Distribu-

tion System Planning (DDSP)] to be used. In other words, this variable reduces total planning costs by determining the best timing schedule for investment in network upgrading.

Moreover, the load duration curve (LDC) is adopted as a suitable model for taking into account load variations along the year [39]. This LDC model is a descending step curve that has N load levels. Each load level has its own annual growth rate. Besides, the influence of the competitive electricity environment is included into the optimization process by defining a more accurate model of the power purchasing scheme. For this purpose, appropriate electricity market prices are considered for each load level for part of the demand that is being supplied from the upstream grid.

Briefly speaking, while the earlier research on DSP either focuses on a static type (in which a single stage is considered) or focuses on a semidynamic type (in which some stages are individually observed; each stage with some inputs from the earlier one) [ex. 3, 7, 8], a fully dynamic type is proposed in this paper where DGs installation are compared with other expansion requirements while:

- some transactions with the electricity market are possible;
- equipment lifetimes are observed; the point dismissed in earlier research.
- various constraints are considered.

So while in the earlier research, the closest methods are the ones that divide the planning horizon to smaller subperiods and solve the problem for each subperiod individually by inputting some parameters from the previous periods, in this paper, each year of the entire planning period is considered as an option for the installation of new facilities. In this way, the problem solution would end up with the best time schedule for equipment investments.

The reminder of this paper is arranged as follows. In Section III, the proposed model is illustrated in detail and the formulation of the objective function and the constraint terms as well as the optimization method are described. In Section IV, numerical results are demonstrated. Tests are designed so that they assess the capabilities of the proposed model. Finally, Section V tries to put the model and the results together and infers the advantages of the proposed approach and suggests further research still to come.

II. Model Description

In this section, the mathematical formulation of the proposed model is presented. The objective function (OF), the constraints, and, finally, the optimization procedure are described.

A. Objective Function

Briefly speaking, the OF is

$$\mathrm{OF} = \mathrm{A} + \mathrm{B} \tag{1}$$

where

$$\begin{aligned}\mathrm{A} = \sum [&(\text{DGs investment cost}), (\text{DGs O\&M cost}),\\ &(\text{System power loss compensation expense})]\\ \mathrm{B} = \sum [&(\text{Investment cost of new transformer}),\\ &(\text{Feeder reinforcement cost}), (\text{The cost of}\\ &\text{purchasing power from the electricity market})].\end{aligned}$$

Before giving some details in A and B terms, it should be mentioned that any equivalent annual cost (AC) is given as [40]

$$AC = \frac{d \times CC}{1 - \frac{1}{(1+d)^{LT}}}. \tag{2}$$

Equation (2) describes the annual investment cost of an equipment (in U.S.$ or U.S.$/MVA), provided that its total investment cost (CC) is known (in U.S.$ or U.S.$/MVA); based on its lifetime (LT in years) and a specified discount rate. The outcome of (2) should be added to the objective function for each year of using the equipment and there is no need to convert it to the present value for future years (it has been included in equation). AC_{DG} or $\mathrm{AC}_{l,u}$ may stand for AC in the above formula. For the definition of these two, see the nomenclature. This way, the different lifetimes of equipment are considered into the objective function.

Coming back to (1), the details of A are given as follows:

$$\begin{aligned}A = &\sum_{t=1}^{T}\sum_{i=1}^{N_{LB}} \beta(IY_{DG\ i})\,\mathrm{AC}_{DG\ i}\\ &\times (S^{M}_{DG\ i} + BK)\,\sigma_{DG\ i,t}\\ &+ \sum_{t=1}^{T}\beta(t)\sum_{k=1}^{N_{LL}} LD_k \sum_{i=1}^{N_{LB}} C_{DG\ i}\\ &\times S_{DG\ t,k,i}\, pf\, \sigma_{DG\ i,t}\\ &+ \sum_{t=1}^{T}\beta(t)\sum_{k=1}^{N_{LL}} LD_k\, C_{SS\ k}\\ &\times \sum_{i=1}^{N_{LB}}\sum_{j=i+1}^{N_T} \mathrm{Re}\{(\boldsymbol{V}_i - \boldsymbol{V}_j)\boldsymbol{I}^*_{ij}\}.\end{aligned} \tag{3}$$

Variables $\sigma_{DG\ i,t}$ (the decision variable; 0 or 1, showing the existence of DG_i in year t) and $S^{M}_{DG\ i}$ (DG_i capacity) are the decision states to be determined by the optimization algorithm. In terms of the first term of (3):

- the investment cost is obtained through adding the annual investment cost over the planning period;
- an extra backup DG (for emergency conditions) is considered to be added at the buses for which a DG is justified; note that whatever capacity is justified for a DG by the algorithm (say 1, 2, 3, or 4 MVA as we will see in Section IV), a fixed and prespecified backup capacity of say $BK = 1$ MVA would be considered for the aforementioned bus.
- Once $IY_{DG\ i}$ is determined by the algorithm as the installation year of DG_i, the DG_i investment cost would be converted to the present value by [41]

$$\beta(IY_{DG\ i}) = \frac{1}{(1+d)^{IY_{DG\ i}}}. \tag{4}$$

In terms of the second term of (3), it shows the cost of O&M for DG units. Backup units are excluded from this calculation by assuming that they are O&M cost free and would be merely used in emergency conditions. Each justified DG unit is assumed to be employed according to its operation costs compared to other

available power sources (such as purchasing from the wholesale power market or other available DGs) so that with $C_{DG\ i}$ in U.S.$/MWh, LD_k is used to calculate the cost over each load-level period (using an OPF). As will be mentioned in Section III-B, each DG can be operated only for its operation time limit over a year. Besides, $\beta(t)$ is employed to convert future costs to present values as given by

$$\beta(t) = \frac{1}{(1+d)^t}. \tag{5}$$

The third term of (3) stands for the cost of compensation of system losses, calculated for various load levels and added for the planning years. Note that LD_k is in terms of hours and the actual load level (in megawatts) is indirectly accounted for in the calculation of $\boldsymbol{V_i}$, $\boldsymbol{V_j}$, and $\boldsymbol{I_{ij}}$.

It is worth mentioning that a DG unit is considered as a negative PQ bus with a fixed and prespecified known pf (say 0.9).

Coming back to (1), the details of B are given as follows:

$$B = \sum_{t=1}^{T} \left(\sum_{l=1}^{N_{SS}} \sum_{u=1}^{N_U} \beta(IY_{l,u})\, AC_{l,u}\, \sigma_{i,u,t} + \sum_{i=1}^{N_{LB}} \sum_{j=i+1}^{N_T} \beta(IY_{f,ij})\, C_{ij}\, \sigma_{ij,\,t} \right) + \sum_{t=1}^{T} \beta(t) \sum_{k=1}^{N_{LL}} LD_k\, C_{SS\ k} \sum_{l=1}^{N_{SS}} \sum_{u=1}^{N_U} S_{l,u}\, pf\, \sigma_{l,u,t}. \tag{6}$$

The reasoning is similar to those mentioned before. Any cost of new transformers (in $IY_{l,u}$ time, first term), feeder reinforcement cost (second term), and the cost of purchasing power from the electricity market (third term) are calculated as detailed from before.

Briefly, once the above objective function (as given by (1)) is minimized, subject to various constraints (as would be given in Section III-B), the following items are determined (independent variables of this problem):

- the position, the installation year, and the capacity of DG units; in this paper, it is assumed that one DG unit may be justified in a year and it would be kept in service for the subsequent years (see Section IV);
- the installation year of any new transformers as well as its capacity; in this paper, two capacities are considered as available alternatives (see Section IV).
- the feeder reinforcement required with sending and receiving buses as well as their required times.

As seen, the problem is a mixed nonlinear integer programming optimization problem.

B. Network Constraints

1) *Network power balance*: Total power consumption should be equal to the production of power supplies. This constraint is complied by calculating a load flow [38], considering the O&M costs of available power sources and dispatching them using an OPF. In this approach, DG units are assumed as negative loads.

2) *Voltage deviation*; Voltage value at each bus should remain within acceptable limits as

$$|V_n - V_i| \leq \Delta V. \tag{7}$$

3) *Maximum DG penetration*: Summation of total DG capacity in the grid should be less than some percentage (say, 30%) of the total load.

4) *Distribution feeder's thermal limit*: The feeder's thermal capacity may be violated as the load grows. If such a problem exists, additional investment would be required for reinforcement of these feeders

$$S_{ij} \leq S_{ij}^{\mathrm{Max}}\, \sigma_{ij}, \quad \forall i \in N_T,\ \forall j \in N_{LB}. \tag{8}$$

5) *DG technology maximum capacity*: DG capacities vary from a few kilowatts to an upper limit of several megawatts.

6) *DG annual operation time limit*: DG units can operate for limited hours in each year. This should be considered into the calculation of O&M costs in the objective function.

7) *Capacity reserve*: As in a bulk power system, here we need the available power supply in case of some unpredictable failures, such as the outage of one or more DG units. To compensate such a condition, a reserve is assumed (say, 10% of the total demand).

8) *Distribution substation capacity limit*: The power delivered by the distribution substation should stay within its nominal capacity.

C. Optimization Procedure

As stated earlier, the proposed model is a mixed-integer nonlinear programming problem. Due to its powerful capabilities in dealing with such problems, the genetic algorithm (GA) is employed to solve the problem. This section illustrates the adoption of a modified GA [42] for obtaining the solution of the DSP model. It starts by producing a series of random decision variables, including DG locations and transformer installation as well as their installation time, grouped as initial population. These decision variables are then fed into another stage for finding their optimum capacities upon an OPF optimization. This step is carried out by means of the proposed model by attaching a composite cost value (objective function value) to each decision variable, which represents the fitness value, and the best DG and transformer capacities. Here, network constraints are observed to be met by adding them with large factors to the fitness function. Therefore, the fitness function is comprised of objective function (1), added with weighted violated constraints. Since the violated constraints are added by large factors, the solution would end up with no constraint violation with the minimum objective function.

The initial solutions are then ranked according to their fitness values and some are selected for the crossover and mutation stages by means of a roulette wheel. After crossover and mutation operations, a new generation is obtained which is fed into the OPF process for the best capacity and fitness value assessment. New solutions are chosen by combining the best ones in new and old populations. This procedure is repeated for a number of iterations. The best answer is saved at the end of each

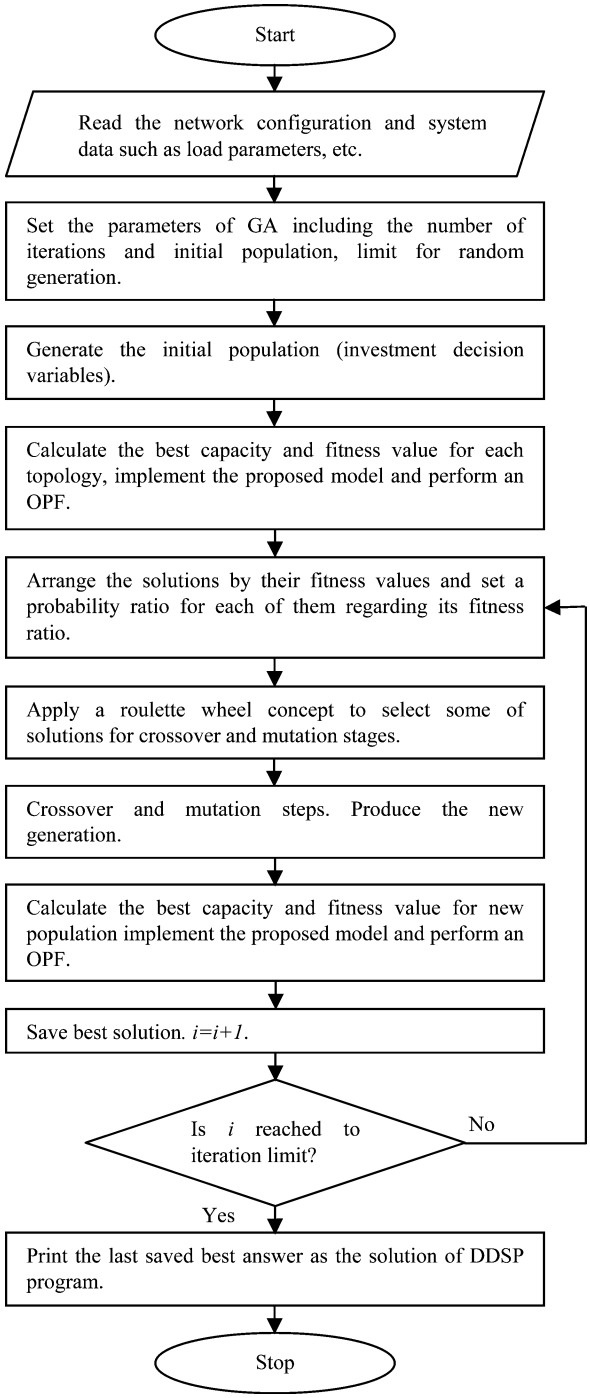

Fig. 1. Optimization procedure.

iteration so that by performing the last iteration, the problem solution is obtained. Fig. 1 shows the optimization procedure.

III. Numerical Results

A. System Under Study 1

A radial distribution network as shown in Fig. 2 is chosen for assessing the effectiveness of the proposed DSP model and the optimization method [1], [2]. This system includes one 132-kV/33-kV substation with 40-MVA capacity (bus-9) and

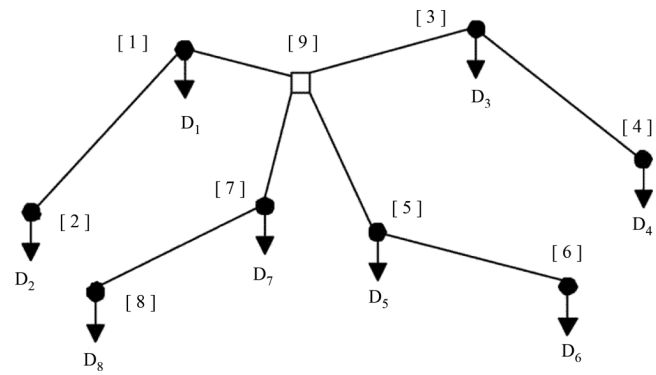

Fig. 2. Network under study.

TABLE I
Review of Literature

Attributes	Reference number
Technical Improvement	[15],[23]-[28].
Loss Reduction	[5], [9]-[15], [19]-[24], [28]-[30].
Reliability Improvement	[9], [14]-[16], [31]-[35].
Investment Cost Minimization	[5], [7], [8], [10], [12], [13], [15], [19], [26], [29], [31], [33], [36], [37].
Operation & Maintenance Cost Minimization	[5], [7], [8], [10], [13], [15], [26], [29], [37].
Maximizing Energy Efficiency	[10]
Grid Investment Deferment	[9]-[14], [19], [32], [35], [37].
Ancillary Service	[14], [32]
Renewable DG Consideration	[29]
Maximizing Social Welfare	[18]
Maximizing DG Owner Profit	[18]
Electricity Price Reduction	[14], [33]

eight load buses, to be supplied in the planning period. The LDC is assumed to be of a three-level type with equal durations, each with its own rate of annual growth and electricity price [43]. Load buses are connected to the grid by 33-kV/11-kV transformers. Network feeders have the thermal capacity of 12 MVA with a cost of U.S.$0.15M/km for the reinforcement purposes.

The natural gas generators are used as DGs due to low land requirements. Their capacities are assumed to be 4 MVA, available in steps of 1 MVA. Their capital costs are assumed to be U.S.$0.89M/MVA with a U.S.$10/MWh rate for O&M expenditures [6]. Also, in any bus that a DG unit is justified, a 1-MVA backup DG is assumed to be added. It is assumed that there is unlimited access to natural gas at all load buses. There are two 10-MVA transformers available for possible installation in the grid substation, each with a cost of U.S.$0.2M. The discount rate is assumed to be 12.5% [13]. The system power factor is taken as 0.9, and the planning period is assumed to be four years. Table II shows the details of different tests performed to assess the effectiveness of the proposed model.

The GA chromosomes consist of 10 binary variables. The first 8 represent the installation of DG units at 8 load buses, and the other 2 variables indicate the investment on each of the two available transformers. Also, there are 10 integer variables in the chromosomes, limited by planning horizon years, corresponding to the installation year of each equipment. Furthermore, an OPF is performed to set the optimum capacity for equipment in each chromosome.

TABLE II
CASE STUDIES

		Case I			Case II	
		Test 1	Test 2	Test 3	Test 1	Test 2
Attributes	Capital Costs	√	√	√	√	√
	O&M Costs	√	√	√	√	√
	Cost of the Losses	√	√	√	√	√
Constraints	Power Balance	√	√	√	√	√
	Voltage Drop	√	√	√	√	√
	DG Penetration Limit	√	√	√	×	√
	Feeder Capacity Limit	×	×	√	√	√
	DG Capacity Limit	√	√	√	√	√
	Capacity Reserve	×	√	√	√	√
	Distribution Substation Capacity	√	√	√	√	√
Load Model	Load Levels	1	3	3	3	3
	Load Growth	*Once*	*Annual*	*Annual*	*Annual*	*Annual*
Power Purchasing Conditions	Load Levels Prices	*The same*	*Different*	*Different*	*Different*	*Different*
	Substation Power	*Additional*	*Additional*	*Additional*	*Total*	*Total*
Flexibility	Programming Method	*Static*	*Dynamic*	*Dynamic*	*Dynamic*	*Dynamic*
Results	Substation Expansion	×	*Table. III, C 4*	*Table. IV, C 2*	*Table. V, C 2*	*Table. V, C 2*
	DG & Substation Expansion	*Table. III, C[a] 2,3*	*Table. III, C 5*	*Table. IV, C 3*	*Table. V, C 3*	*Table. V, C 4*

[a]C Stands for the column of the respective table

TABLE III
DDSP WITH UNLIMITED FEEDER CAPACITIES

	Reference [13] results	Simple Case	Substation Expansion	DG & Substation Expansion
Total Expansion Cost (M$)	25.808	25.567	8.539	8.036
Additional Final Peak Purchased Power (MVA)	0.7328[a],0	0.439, 0	5.0312, 10	6.2128, 0
Total Losses (GWh)	51.49	49.98	60.60	52.73
Total System Peak Demand (MVA)	52.732	53.674	55.0312	54.2128
Transformer Expansion Substation Cost (M$)	0.2(1)	0.2(1)	0.184 (1, 2)	0.184(1,2)
DG Capacity (MVA)&Location	3(4MVA&1MVA) @buses 2(1), 6(1), 8(1)	3(4MVA&1MVA) @buses 2(1), 4(1), 8(1)	–	2(4MVA&1MVA) @buses 4(3), 8(4)
DG Investment Cost (M$)	7.5	7.5	–	1.835
Cost of Losses(M$)	2.703	2.9213	2.407	2.095
Additional Purchased Power Cost (M$)	1.213	0.7281	5.948	3.467
DG O&M Costs (M$)	14.191	14.218	–	0.456

[a]The power that is delivered by each of the two transformers at peak load condition in the last planning year

B. Case I

Due to the high capital cost of an existing substation transformer, it is assumed that the load demand is primarily supplied through the substation transformer and only the load in excess of its capacity (40 MVA) is supplied by DG units. And this is true in the entire planning years in this case. Thus, only additional power, which needs to be purchased from the distribution substation (in excess of 40 MVA), is included into evaluations. To demonstrate the effectiveness of the proposed model and the optimization approach, the one presented in [13] is performed here with its similar conditions in the first test of this case. Taking the feeder thermal capacities into account (it may be violated as the load grows and new equipment need to be installed in the grid), and for economic comparisons, two conditions, namely: 1) considering adequate capacity of feeders and 2) the need for reinforcement of feeders, are considered.

1) Test 1: Simple Case: This case is based on the model presented in [13] and performed for comparison purposes. As in Table III, the results obtained from this case are almost the same as in [13]. The slight differences could be due to different optimization methods and the inaccessibility of the full data provided in [13].

2) Test 2: Assuming an Unlimited Capacity for any DISCO Feeder: In traditional DSP, two additional transformers are justified at the substation so that one of them works at full capacity and other one in 50% of its rated power.

As the results show, considering DG as an option results in a total cost reduction of 6% (8.539 in comparison with 8.036) while the losses are decreased by 13%. Here, one group of DGs is justified. This group consists of two sets of 4 MVA DGs and 1 MVA back up DGs in buses 4, and 8 which are to be installed in years 3 and 4, respectively (denoted as 2(4 MVAand 1 MVA) at buses 4(3), 8(4), in Table III, column 5). In this way, investment reduction of DISCO results in lowers customer bills. In a competitive environment that several utilities are trying to survive, this will be an important advantage. On the other hand, purchasing power with lower costs has its own social benefits.

By comparing technical characteristics of two different DSP plans, it is clear that with DGs, operational conditions are improved. Fig. 3 depicts bus voltages for the two plans. As seen,

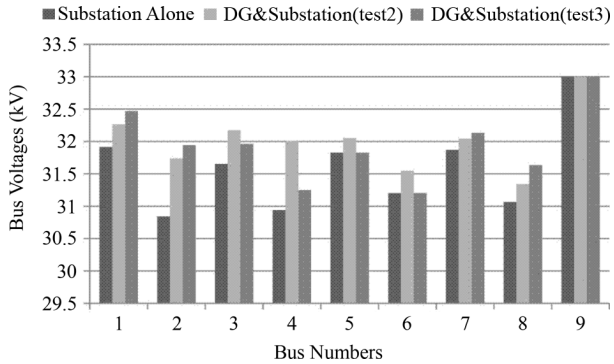

Fig. 3. Bus voltages in case I.

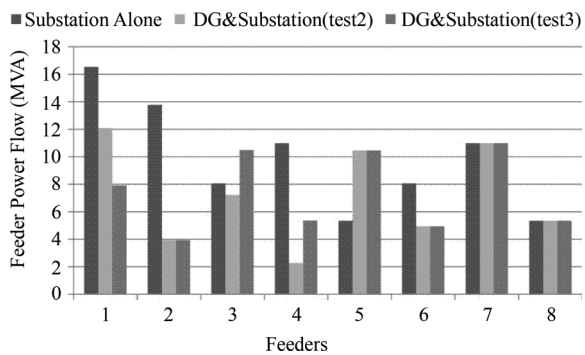

Fig. 4. Power flow in feeders for case I.

installation of DG units may improve the voltage profile of the system. In Fig. 4, power flows with and without DGs are shown. It is obvious that there is a reduction in power flow of some feeders once DGs are employed. In this way, feeder lifetime may be extended.

3) Test 3: Considering Capacity Limits for Feeders: Comparing total cost values of two plans shows 25% cost reduction and 25% loss reduction upon implementing DGs (Table IV). As expected, voltage and line flows for substation expansion planning alone are the same as in the case of substation expansion, assuming adequate feeder capacities. The difference is only in total cost which is the result of feeder reinforcement. But DG units' configuration for DDSP are different from the case where line capacities are ignored. This shows, in that scheme, some feeders' thermal capacities may be violated (which has no impact on the objective function value) and, therefore, when feeder capacities are included in the model, the cost imposed by reinforcement of feeders results in some changes in the DG configuration plan (to avoid the cost of feeder reinforcement). Therefore, in this case, DG locations and capacities are arranged in such a way that no feeder capacity violation occurs, resulting in higher total cost in comparison with the case where line capacities are ignored.

Fig. 3 depicts the voltage profiles of two DSP plans. As shown, the voltage magnitude improvement in the DDSP plan is evident. The maximum voltage drops for substation expansion alone and DDSP are 7% and 5%, respectively. In Fig. 4, the line flows are shown. As in Fig. 4, line flows are less

TABLE IV
DG AND SUBSTATION EXPANSION PLAN CONSIDERING FEEDERS' THERMAL CAPACITIES

	Substation Expansion	Dynamic DG & Substation Expansion
Total Expansion Cost (M$)	12.4	9.295
Additional Final Peak Purchased Power (MVA)	5.0312, 10	5.1506, 0
Total Losses (GWh)	60.60	45.35
Total System Peak Demand (GWh)	55.0312	54.1506
Transformer Expansion Substation Cost (M$)	0.184 (1, 2)	0.110 (1)
Feeder Cost (M$)	3.862	0
DG Capacity (MVA) & Location	–	1(4MVA&1MVA) @buses 2(1), 2(2MVA&1MVA) @buses 4(3),7(3), 1(1MVA&1MVA) @buses 1(4),
DG Investment Cost (M$)	–	4.965
Cost of Losses (M$)	2.407	1.742
Additional Purchased Power Cost (M$)	5.9481	1.429
DG O&M Costs (M$)	–	1.049

than the feeders' capacity limits for DG planning. In this case, the optimization process determines DG locations and sizes in such a way that line flows remain within their limits. In the case discussed before, observing the thermal capacity limits of the feeders has resulted in more investment and more power loss of the grid. In terms of the first conclusion, this generally holds for other cases as imposing some constraints would likely result in more investment. In terms of the second conclusion, this may not be generally true for all cases. In other words, observing the thermal capacity limits may result in higher or lower losses, depending on the net cost function minimization.

C. Case II

In this paper, three attributes, namely, investment cost, O&M cost, and power losses compensation are selected for optimization of DSP. In this case, the influence of O&M costs on installation of new facilities will be examined. For this purpose, total delivered power to the grid is included in (3). Here, the total cost of the power supplied by the distribution substations is evaluated and added to objective function and DDSP is solved for two conditions: 1) ignoring the DG penetration limit and 2) considering all constraints.

1) Test 1: Ignoring the DG Total Capacity Penetration Limit: In this case, it is assumed that no problem occurs, regardless of the number of DGs installed in the network.

As in Table V, there is a total cost reduction of 13% and a 68% decrease in power losses, showing a substantial effect of DGs on power saving and environmental concerns Nearly U.S.$7M is saved in comparison with the previous cases. As seen, all available DG units are justified. This test indicates the importance of O&M costs in a DSP problem.

Fig. 5 shows the bus voltages of this case. Compared with the two previous cases, it is obvious that DG implementation in the grid could be a key solution for solving voltage problems. As seen, the maximum voltage drop is 3%.

TABLE V
NUMERICAL RESULTS FOR CASE II

	Substation Expansion	DG & Substation Expansion (test 1)	DG & Substation Expansion (test 2)
Total Expansion Cost (M$)	50.577	43.568	44.759
Additional Final Peak Purchased Power (MVA)	5.0312, 10	0, 0	0, 0
Total Losses (GWh)	60.60	19.45	31.55
Total System Peak Demand (MVA)	55.0312	52.7865	53.6236
Transformer Expansion Substation Cost (M$)	0.184 (1, 2)	0	0
Feeder Cost (M$)	3.862	0	0
DG Capacity (MVA) & Location	–	8(4MVA&1 MVA) @buses 1(1), 2(3), 3(3), 4(1), 5(3), 6(1),7(2), 8(1)	3(4MVA&1 MVA) @buses 2(2),4(1),8(1), 1(3MVA&1MVA) @buses 1(1),
DG Investment Cost (M$)	–	18.814	11.146
Losses Cost (M$)	2.407	0. 585	1.106
Purchased Power Cost (M$)	44.125	19.936	30.081
DG O&M Costs (M$)	–	4.233	2.425

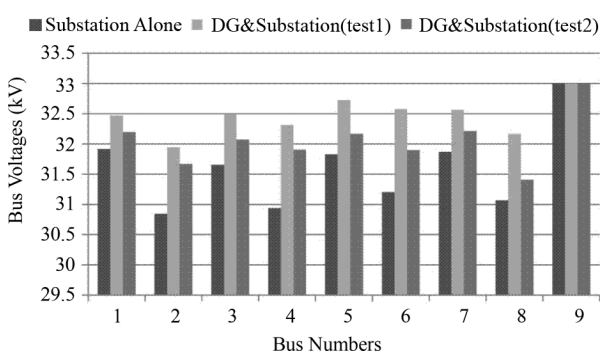

Fig. 5. Bus voltages for case II.

As in Fig. 6, in this situation, line flows are substantially reduced, resulting in a reduction of network power losses; 68% of the case of substation expansion alone.

2) Test 2: DDSP Considering all Constraints: In a more realistic condition, the network capacity for absorbing DG units is limited and excessive installation of DGs may result in stability and security problems. Hence, in this case, the comprehensive model of the DDSP problem is solved taking into account all previously mentioned constraints, while all O&M costs are included into the optimization procedure.

Here, the planning solution for the traditional approach is the same as previous cases. However, the outcome of the DDSP plan for the DG and substation expansion method shows a 12% reduction in investment costs (equivalent to U.S.$6M). It is clear that also in this condition, substantial savings are achieved. In addition, there is 47% loss reduction, due to fewer power flows

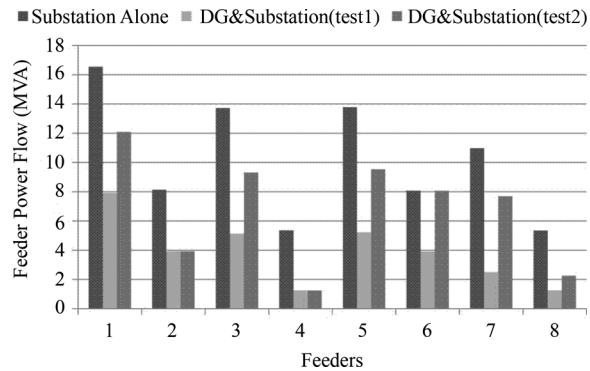

Fig. 6. Power flow in feeders for case II.

in the feeders and closeness of the electrical resources to demand points.

Also, as shown in Fig. 5, bus voltages are improved by considering DGs in distribution systems. In Fig. 6, feeders' power flows are depicted, showing great reduction in line flows in the grid.

Overall, in terms of the global optimality of the solution, it should be mentioned that this cannot be mathematically proved for the genetic algorithm (GA). However, GA has proven to have a good chance of reaching the global optimum solution [44].

IV. CONCLUSION

The appearance of DG units in distributions systems has resulted in new challenging research areas. In this paper, DDSP was proposed where a year-dependent decision-making variable was defined into the model. The load duration curve (LDC) was used to include the way that the customer loads may change. Also, the impact of the electricity market was considered by a load-dependent electricity price. The optimization problem solved was based on three objective function terms, namely: 1) the investment cost; 2) the O&M cost; and 3) the cost of power losses. Various constraints were also observed. The capabilities of the proposed algorithm were assessed and appreciated through some case studies on a typical distribution system.

The large penetration of DG units in a distribution system may impose some other technical and/or economical impacts; such as protection and communication equipment.

The cases discussed in this paper implicitly assume that new DGs may be installed by DISCO. Although it may be practical in some cases, it may not be true for some situations, as the private sector may be active in such investment. Moreover, uncertainty in load and DG generations may be required to be observed in the optimization model. Besides, the market type used is a one-way pool type, while more complicated market models may be considered. If renewable DGs are to be considered, probabilistic models should be used and developed. These points require more investigations and may be considered as further work.

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