Independent Distributed Generation Planning to Profit Both Utility and DG Investors

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***Abstract*—Most current regulations allow small-scale electric generation facilities to participate in distributed generation (DG) with few requirements on power-purchase agreements. However, in this paper, it is shown that distribution companies can alternatively encourage DG investors into DG contracts that can significantly benefit the utility network. In this regard, a new algorithm is proposed to determine the best sites, sizes, and optimal payment incentives under such special contracts for committed-type DG projects to offset distribution network investment costs. On one hand, the aim is to allocate DGs such that the present value profit gained by the distribution company is maximized via procuring power from DGs and the market at a minimum expense. On the other hand, each DG unit's individual profit is taken into account to assure that private DG investment remains economical. The algorithm is verified in various cases and the impacts of different factors are accordingly studied.**

***Index Terms*—Distributed generation, investment incentives, optimal location, price allocation, size, utility profit.**

NOMENCLATURE

n_{DG}	Number of DG units.
n_{start}	Year of starting generation in DG contract.
n_{end}	Year of ending generation in DG contract.
$n_{periods}$	Number peak periods in DG contract.
PVB_{DG_i}	Present value benefit for ith DG.
PVC_{DG_i}	Present value cost for ith DG.
$H(k)$	Total number of hours in kth peak period.
$P_{DG_i}(k)$	Active power of ith DG in kth period (kW).
$S_{DG_i}(k)$	Apparent power of ith DG in kth period (kVA).
$PF_{nominal}$	Nominal power factor of ith DG.
$P_{load}(j,k)$	Load in kth period of jth year (kW).
$P_{net}(j,k)$	Power procured in kth period of jth year (kW).
$C_{offer}(i,k)$	Tariff rate for ith DG in kth period (kWh).
$C_{capital}$	DG capital investment cost ($/kW).
C_{fuel}	DG fuel cost ($/kWh).
$C_{O\&M}$	DG operation and maintenance cost ($/kWh).
C_{market}	Wholesale market price ($/kWh).
C_{retail}	Price rate for retail customers ($/kWh).
i_f	Nominal interest rate.
PEL	Project's economic life.
λ_i	Installation cost coefficient of ith DG.
T_{DG}	Classified type of DG.
I_{DG}	Installed capacity of DG (kVA).
P_G	Total injected active power at a node (kW).
Q_G	Total injected reactive power at a node (kW).
P_D	Active power demand at a node (kW).
Q_D	Reactive power demand at a node (kW).
V_i	Voltage magnitude of ith bus.
δ_i	Voltage angle of ith bus.
K_V	Penalty for violating voltage tolerance.
K_S	Penalty for violating transmission capacity.
$\mathbf{x}_{n,m}$	nth member vector of mth generation.
$\mathbf{v}_{n,m}$	nth mutant vector of mth generation.
Cr	Cross over probability ratio.
ζ	Differential variation control parameter.

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I. INTRODUCTION

THE increasing growth in electric load has made the traditional vertically integrated power systems inefficient due to the significant investment cost of transmission and distribution systems expansion. Therefore, there is a growing interest towards a distributed generation (DG) paradigm to provide small-scale generation opportunities close to consumer sites. Furthermore, DG systems can benefit from short lead time and low investment risk, small physical sizes, and flexibility in locations. For example, they can be installed nearly everywhere without the land availability challenges of traditional power plants. Due to these and many other advantages, DG is expected to play a significant role in the power grid's operation, structure, design, and upgrading planning [1], [2].

There exists a wide range of algorithms in the literature for the purpose of distribution planning incorporating DGs. One thread of research focuses on optimization-based approaches with a *single* objective function, e.g., with respect to power losses, voltage profile, and total generation or distribution costs. In [3], the authors proposed an algorithm to determine the optimum locations of DGs to minimize power losses. In [4], an optimal planning framework is introduced to minimize the total system planning costs for DG investment, operation, maintenance, as well as the cost of purchased power and system losses. In [5], the Artificial Bee Colony algorithm is applied to determine the optimal size, power factor, and location of DGs to minimize the total real power loss in the system. Another thread of research in DG planning involves optimization-based approaches with *multiple* objectives. For example, a particle swarm optimization algorithm is introduced in [6] to determine the location and size of DGs considering voltage profile, total harmonic distortion reduction and losses on distribution lines. Another multi-objective algorithm is developed in [7] to minimize the losses, investment cost in new facilities and distribution lines, and the number of faults and the lengths of interruption times. A heuristic approach for DG investment planning is proposed in [8] that aims to minimize the distribution company (DISCO)'s investment costs, operation costs and the costs related to system losses. It works by searching for a set of DGs that can have their marginal benefits greater than their overall installation and operation cost. Finally, in [9], a multi-objective approach is proposed to determine the optimal size and location of DG units, considering various implementation challenges, using the particle swarm optimization.

Most of the previous studies, such as those in [3]–[10], focus on reducing the investment and running costs of DISCO, including the cost for installing new DG units. In this regard, they implicitly assume that the DISCO is solely responsible for the *investment* and *operation* of the DG units. However, in many practical scenarios, distribution companies purchase power from *independent* DG owners without being directly involved in investment or operation [11]. To address this issue, in [12], the authors apply the concept of local marginal prices (LMPs) to distribution generation to maximize the social welfare between DISCO and DG providers. Similarly, in [13], DG units are positioned based on LMPs, power loss reduction, and voltage improvement criteria. However, unlike the wholesale electricity markets, the distribution systems are *not* fully decentralized and a single utility company usually operates across a region. Finally, in [14], increasing economic benefits for DG investors is addressed, but there is no consideration of achieving the optimal utility network performance or maximizing DISCO's profit. Therefore, a major challenge for a DISCO while implementing purchase-based procurement of power is to enforce optimal system performance across several independently owned and operated DGs. The key question that needs to be answered is: *How can a DISCO encourage the DG investors and operators into special contracts which can benefit the utility and enforce optimal overall grid performance?* Answering this challenging question is the main focus of this paper. Our contributions can be summarized as follows.

- First, a detailed economical model is developed for DG installation in distribution networks. Our model determines the optimum location, capacity, generation amount in different load levels (namely at on-peak and off-peak periods), as well as retail power procurement prices for each DG unit in each period of time.
- A new optimization problem is developed to maximize the total profit gained by the distribution company while *maintaining the investment attractive* for independent DG owners and operators by keeping DG profitable.
- Our design takes into account various parameters: the network upgrade costs, including the costs for expanding line segments and transformers, the value of released capacities, DG's lead time, different investment conditions in each bus which could be due to different land value or environmental standards, different daily load levels, future demand growth, power losses, and voltage profile.

Paper Organization: Section II describes the problem formulation. Section III presents the proposed algorithm and its implementation aspects to choose the best sites and sizes with optimized offered prices for power delivery. The case studies and the performance assessments are done in Section IV. The conclusions and future work are discussed in Section V.

II. Problem Formulation

A. Problem Description and Background

Many independent system operators (ISOs) have already established policies to facilitate integration of on-site efficient generation, in accordance with their country/state administration objectives in supplying renewable and distributed generation. For example, in many countries, the Renewable Portfolio Standards (RPS) and Renewable Obligation Orders (RO) mandate electricity providers to serve a portion of their load from renewable resources. Although these regulations help the growth of DGs, they do not attempt to optimize the operation and expansion of the distribution networks. As a result, while utilities have to operate in accordance with RPS regulations, they are individually responsible to ensure economic procure of power. Furthermore, despite the supportive regulations and policies, it is still the case that sometimes the DG investors may find the long-term payback time of the project uneconomical [14]–[16].

Tackling the above problems is our focus in this paper. Our system model is within the framework of some existing DG structures in the United States. For instance, consider the Sacramento Municipal Utility District in California, where the feed-in contracts are available for renewable generating units up to 5 MW, including combined heat and power (CHP) units with a certain required level of pollution standards. These contracts are to sell generation at different periods of time, such as on-peak or off-peak hours, under long-term 10-, 15-, or 20-year power purchase agreements [17]. The prices offered by the DISCO are usually set to be fixed at different buses and for the whole duration of the contract, depending on the start date of project. Similarly, in this paper, it is assumed that the DISCO offers standard agreements for DGs, which may include CHP units, and the DISCO has to pay the contracted DG owner at the minimum standard rate in every bus.

Within the practical framework described above, one option to reduce the costs of utilities and to make the investment more attractive, is to encourage certain DG projects that are strategically located with financial benefits for lowering the distribution costs. In other words, distribution companies may increase the offered price to even more than standard tariffs for certain DG projects at certain buses, considering the location, size, technology, and potential external costs (e.g., impacts of the gas infrastructure and real-estate aspects) in order to encourage investors into providing desired on-site generation in desired locations. The DG units considered are the CHP units capable of operating at base load to provide committed generation. In the rest of this section, the focus is on formulating a new optimization problem to find the best allocation for the DG sites, sizes, and prices to maximize the DISCO's profit while attractive investment for the DG owners is guaranteed. The algorithm needed to solve the formulated optimization problem will be developed later in Section III.

B. Optimization Problem

The objective of the proposed optimization problem is to maximize the DISCO's profit; while maintaining positive profit for each *individual* DG in the system to assure DG investment attractive. Profit is evaluated in terms of Net Present Value (NPV), a concept in finance that takes into account all the capital investment costs, variable costs during the term of a project, as well as the revenues gained during the planning term. In this regard, the NPV indicates the net present total profit gained with a target interest rate [18]. The optimization problem can be formulated as follows:

$$\begin{aligned} &\textbf{maximize} \quad NPV_{DISCO} \\ &\textbf{subject to} \quad NPV_{DG_i} \geq 0, \quad i = 1, \ldots, n_{DG} \end{aligned} \tag{1}$$

where for the ith DG, NPV_{DG_i} can be obtained in terms of present values for benefit and cost:

$$NPV_{DG_i} = PVB_{DG_i} - PVC_{DG_i}. \tag{2}$$

The present value of DG's costs can be written as

$$\begin{aligned} PVC_{DG_i} = &\left(\frac{(i_f+1)^{n_{end}}-1}{i_f.(i_f+1)^{n_{end}}}\right).\left(\frac{i_f.(i_f+1)^{PEL}}{(i_f+1)^{PEL}-1}\right) \\ &\times \lambda_i.C_{capital}\left(T_{DG_i}\right).I_{DG_i} \\ &+\sum_{j=n_{start}}^{n_{end}} \frac{1}{(i_f+1)^j} \\ &\times \left(\sum_{k=1}^{n_{periods}} P_{DG_i}(k).H(k)\right. \\ &\qquad \left.\times \left[C_{fuel}\left(T_{DG_i}\right)+C_{O\&M}\left(T_{DG_i}\right)\right]\right). \end{aligned} \tag{3}$$

To reach (3), all the cash flows that the ith DG receives or pays are discounted back to their present values before they are added together in the summation term. Note that the present value (PV) of DG's future annuities during the contract is obtained with respect to a future value (FV) in period n as

$$PV = \frac{FV}{(1+i_f)^n} \tag{4}$$

where the nominal interest rate i_f is usually greater than the real interest rate that an investor expects to receive. The nominal interest rate is obtained from the real interest rate, r, by considering inflation rate p, according to

$$i_f = r + p + r.p. \tag{5}$$

Here, r is set to the minimum acceptable rate of return $(MARR)$ for DG investors. Clearly, if the NPV_{DG} considering $MARR$ becomes negative, then the DG investment fails to meet the minimum expectation and becomes uneconomical.

The payment period in (3) is assumed to be one year and the payments are made at the end of each year. For investments with PEL greater than n_{end}, obtaining the present value requires two steps. First, the capital cost is distributed evenly across the future annuities during the project's economic life. Then the present value of these annuities are added together for the duration of contract. The capital investment for DG is determined regarding its installed capacity, while its variable costs are defined according to each period's generating level (e.g., on-peak or off-peak periods), and the duration of each period. Both capital and variable costs depend on the classified type or technology of the DG. The capital costs also depend on the location of DG which are represented in (3) by λ_i. Finally, note that the variable costs begin at the start time of project, which depends on the DG installation lead time.

Following similar discussions as above, the present value of benefits that the ith DG gains can be obtained as

$$\begin{aligned} &PVB_{DG_i} \\ &= \sum_{j=n_{start}}^{n_{end}} \frac{1}{(i_f+1)^j} \sum_{k=1}^{n_{Periods}} \left(P_{DG_i}(k).H(k).C_{offer}(i,k)\right). \end{aligned} \tag{6}$$

Finally, the NPV of all the cash flows for the DISCO is

$$\begin{aligned} &NPV_{DISCO} \\ &\quad = \sum_{j=1}^{n_{end}} \frac{1}{(i_f+1)^j} \sum_{k=1}^{n_{periods}} \left(P_{load}(j,k)H(k)C_{retail}(k)\right) \\ &\quad - \sum_{j=1}^{n_{end}} \frac{1}{(i_f+1)^j} \sum_{k=1}^{n_{periods}} \left(P_{net}(j,k)H(k)C_{market}(k)\right) \\ &\quad - \sum_{i=1}^{n_{DG}} PVB_{DG_i} + CRB. \end{aligned} \tag{7}$$

Note that the revenue of the DISCO is provided by selling power to the retail customers. Of course, the load level may change during different daily and seasonal periods and the total demand may also experience an annual growth. Therefore, both P_{load} and P_{net} may take different values over the years and in different time periods. Since P_{net} also includes the network losses, therefore, reducing the losses means reducing the total amount of procured power. In (7), the expenses considered for the DISCO include the payments to the DGs and the cost of procuring the excess power from the wholesale market. While the market price is changing during the day, the customer rates are normally constant; in the optional time of use programs, limited tiers of price rates in summer or winter season (e.g., two rates in SMUD) are considered [17]. The payment of DISCO to the DGs is equal to the total revenue that all DGs will have, thereby being the sum of PVB_{DG_i}.

It is worth mentioning that the DISCO expenses may also include the investment costs for upgrading the network transformers and line segments in order to meet the growing demand in the upcoming years. Installing DG may lower these expenses by releasing the network capacity and hence postponing the network upgrade. The benefit gained from delaying the network upgrades, which is referred to as capacity release benefit (CRB), is obtained by calculating the network expenses of the upgrades during the planning term, when a particular set of DGs are installed, and subtracting from the network upgrade costs when no DG is installed. By performing power flow in the successive years of the planning term and in different load levels, the anticipated year in which each line segment or transformer will be over loaded is obtained and the costs related to its upgrade is discounted back to present. By replacing (2)–(7) in (1), the formulation of the proposed optimization problem is complete. However, in order to have a practical and implementable design, there is also a need to include some other constraints in the optimization problem which are explained in detail in the next sub-section.

C. Additional Optimization Constraints

- **Active and reactive power balance equations**: The sum of active and reactive power flows injected into a node should match the power flows extracted from that node. Note that $P_G(i)$ in buses which include distributed generation also includes P_{DG_i}. Furthermore, note that P_{net} is equal to the power injection in the first bus, i.e., $P_G(1)$. A similar statement is true for the reactive power injection:

$$\begin{aligned} &P_G(i)-P_D(i)\\ &\quad=V_i.\sum_{j=1}^{n_{nodes}}[V_j.(G_{ij}.\cos(\delta_i-\delta_j)+B_{ij}.\sin(\delta_i-\delta_j))] \qquad \text{(8a)}\\ &Q_G(i)-Q_D(i)\\ &\quad=V_i.\sum_{j=1}^{n_{nodes}}[V_j.(G_{ij}.\sin(\delta_i-\delta_j)-B_{ij}.\cos(\delta_i-\delta_j))]. \qquad \text{(8b)}\end{aligned}$$

- **Bus voltage limit**: Bus voltages must remain within the acceptable range of levels in all periods:

$$V_i^{min} < V_i < V_i^{max}. \tag{9}$$

- **Transmission injected power limit**: Regardless of distribution substation upgrades, the transmission system may have a limited capability in supporting the distribution substation. Therefore, with growing demand $P_{net}(j,k)$, i.e., the difference between load and local provided generation should be lower than a maximum value:

$$P_{net}(j,k) < P_{max} \quad \forall j,k. \tag{10}$$

- **Generating unit capacity**: The limited generating capacity of the units cannot be violated at any time:

$$\begin{aligned} 0 < S_{DG_i}(k) < I_{DG_i} \qquad i=1,\ldots,n_{DG},\\ S_{DG_i}(k)=\frac{P_{DG_i}(k)}{PF_{nominal}(T_{DG_i})}.\end{aligned} \tag{11}$$

- **Offered price limit**: Each electrical corporation has to obey the standard tariffs by purchasing electricity from small-scale electric facilities at the price set by the commission, which is known as market price referent (MPR) and reflects the market price. Therefore, the contract purchase prices should be at least as high as the MPRs:

$$C_{offer}(i,k) \geq MPR(k) \quad k=1,\ldots,n_{periods}. \tag{12}$$

Together, (1)–(12) formulate our proposed optimization problem. Once solved, the optimal solution allocates the distributed generation sites, sizes, and prices, such that the DISCO's profit is maximized, all DG owners' individual profits are guaranteed, and the solution is assured to be implementable in practical scenarios. Next, in the next section it is showed how the problem (1)–(12) can be solved numerically.

III. Optimal Allocation Algorithm Using Differential Evolution

The optimization problem formulated in (1)–(12) is very challenging as it cannot be solved using classic optimization techniques, such as the linear or convex programming methods [19], [20]. Therefore, here, it is proposed to solve (1)–(12) using the differential evolution (DE) algorithm, which was originally proposed to solve non-convex discontinuous optimization problems [21]–[23]. Here, DE is used over a continuous space optimization. Our other modifications of the DE algorithm include applying some individual constraints in initialization and also after cross over. The flow chart of proposed DE algorithm to solve optimization problem (1)–(12) is depicted in Fig. 1. In the DE algorithm, the population individuals or vectors evolve under algorithm operators, mutation, and cross over, to generate new populations with better objective values. This evolution continues until the objective values of the population get close to each other and to that of previous generations. The implemented algorithm has three main elements to be described in the next three sub-sections.

A. Initialization Phase

Differential evolution is a population-based algorithm, where a population of individuals, each consisting of a particular arrangement of control variables, is seen as a possible solution to the optimization problem of interest. In each generation, a new set of solutions are generated to find a better fitness, a greater objective value, i.e., a higher overall profit. The first step in utilizing a DE algorithm is to define the control variables. In our model, each individual or vector from each generation m consists of the following variables:

$$\begin{aligned} \mathbf{x_{n,m}} &= [I_{DG_i}, P_{DG_i}(k), C_{offer}(i,k)]\\ &\quad i=1,\ldots,n_{DG}, \quad k=1,\ldots,n_{Periods}.\end{aligned} \tag{13}$$

From (13), the control variables in each node consist of the installed capacity, the committed generating level in different pe-

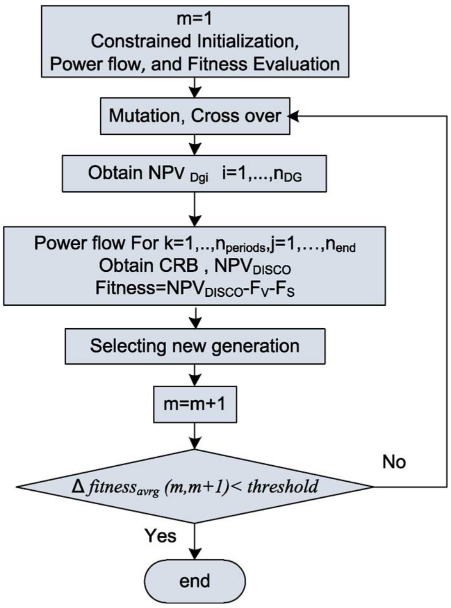

Fig. 1. Flowchart of the proposed DE algorithm to solve problem (1)–(12).

riods, and their associated offered price tariffs. Since the number of candidate DG locations are limited compared to the DG capacities and given the fact that the choice of location can significantly change the outcome of the objective function, it is better to make sure that the program examines *all* candidate locations at which a DG can be sited. Therefore, since each vector in (13) contains the active power generation in each available node of the distribution system; we set n_{DG} in the initialization phase to be equal to the network's available locations. Note that although the DG units are initially placed in all locations, quite a few of the DG units will remain in the successive generations until the optimum solution is obtained and the generation in many nodes will gradually be eliminated. While I_{DG_i} takes integer values between available DG types, $P_{DG_i}(k)$ and $C_{offer}(i,k)$ are continuous variables. The initial value of the control variables are determined using randomization to assign each parameter of the nth vector, a value within its upper and lower bounds. Such initialization is done for all elements in each $\mathbf{x}_n$. The population size is considered as four times of the number of control variables. In order to avoid calculating the fitness for infeasible solutions and to reduce computational complexity, the initial values of parameters related to $x_{n,1}$ should meet

$$\sum_{i=1}^{n_{DG}} P_{DG_i} < P_{load}(k), \qquad k = 1, \ldots, n_{periods}. \tag{14}$$

Otherwise, the solution is infeasible and must be replaced. It should also be verified that with the determined generation levels and price tariffs, whether the unit operation will be economical. To do this, for each $\mathbf{x}_n$, all NPV_{DG_i} with the pre-set price tariffs and generating levels are determined. Note that NPV_{DG_i} must be positive. Furthermore, generating in each period under the associated price tariffs should be beneficial. That is, it should be more than the current revenue gained by generating at peak hours in post-contract life of DG, assuming the unit has a limited total hours of efficient operation and it can generate later under standard contracts. This constraint is checked at all periods for each DG unit. If the generation levels in all periods for DG_i are zero or if NPV_{DG_i} is negative, then the DG_i capacity is set to zero and the DG is eliminated.

B. Power Flow and Fitness Evaluation

For each $\mathbf{x}_n$, the power flow is performed in every period of each year during the planning stage. The voltage violations and line flows are obtained for every year, as well as the excess power to be procured from the network. Then, the CRB is calculated according to Section II-B and the NPV_{DISCO} is as in (7). The fitness function is obtained as

$$Fitness(\mathbf{x}_n) = NPV_{DISCO} - F_V - F_S \tag{15}$$

where

$$F_V = K_V . \sum_{l=1}^{n_{end}} \sum_{k=1}^{n_{Periods}} \sum_{j=1}^{n_{nodes}} max(0, V_{min}(l,k,j) - V_j, V_j - V_{max}(l,k,j)) \tag{16}$$

and

$$F_S = K_S . \sum_{l=1}^{n_{end}} \sum_{k=1}^{n_{Periods}} max\left(0, S_{net}(l,k) - S_{max}\right) \tag{17}$$

denote the penalty functions related to violating the voltage profile tolerance or violating the transmission capacity limit. Here K_V and K_S usually take large values to eventually remove an infeasible solution from the next generations.

C. Applying the DE Operators, Obtaining the New Generation

Once the fitness functions are obtained, we apply the DE operators of *mutation*, *cross-over*, and *selection*. The details on how these operators are applied can be found in [21]–[23]. Note that here, the mutant vector is obtained as

$$\mathbf{v}_{n,m} = \mathbf{x}_{r_1,m} + \zeta\left(\mathbf{x}_{r_2,m} - \mathbf{x}_{r_3,m}\right) \tag{18}$$

where r_1, r_2, and r_3 are random integers to choose different random vectors from the current population. The control parameter ζ is chosen within [0.5, 1]. Smaller values of ζ are usually used for larger population sizes. Here, we set $\zeta = 0.7$ by experiment. In fact, it was observed that the lower values of ζ may help the algorithm converge faster. However, in small population sizes, this may cause the algorithm to reach a local minimum, rather than a near global optimum, confirming the trade-off between DE optimality and convergence speed [23]. For our design, a uniform cross-over is used. In our analysis, $Cr \in [0,1]$ the parameter that controls the fraction of parameters copied from the mutant vector is set at 0.3 [21]. The three steps of mutation, cross-over, and selection are repeated for each generation until the termination criteria is met, i.e., the difference between the average fitness values of successive generations drop below a pre-determined level. A maximum number of generations are also considered as an additional criterion for termination. Once the algorithm converges, the optimal solution of problem (1)–(12) is achieved.

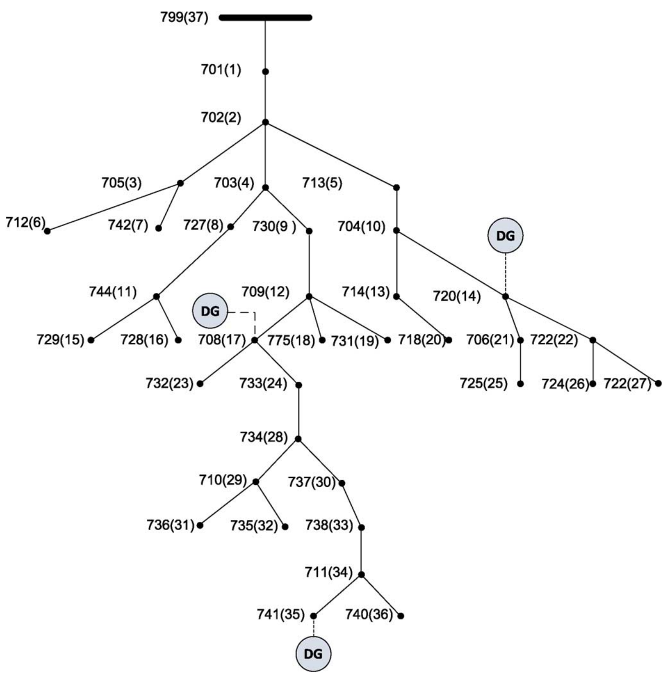

Fig. 2. IEEE 37-bus distribution system with renumbered buses.

TABLE I
UNDERGROUND CABLE LINE CONFIGURATION DATA

Config.	Cable(AWG)	Conductor size (mm^2)	Ampacity (A)	Price($/m)
721	1000AA,CN	3500	550	213
722	500AA,CN	3240	385	161
723	2/0AA,CN	370	200m	64
724	2# AA,CN	335	135	41

IV. CASE STUDIES

The modified IEEE 37-bus distribution system which is an actual feeder located in California has been used to test the functionality of the proposed algorithm [24]. The graph diagram of this network, with renumbered branches and nodes, is depicted in Fig. 2. This system serves a total demand of 2.63 MW and 1.55 MVAR reactive power. The distribution transformer capacity is 3200 kVA with a rough value of $50 000. The characteristics of different cable types, used in line segments and their rough per meter prices, as well as their maximum allowable currents are shown in Table I [25]. The demand curve takes different values during the day. The load level considerably changes from the morning to the afternoon and at night. The demand also slightly varies at each hour of these periods. Therefore, the load curve can be approximated to several periods with an average level of demand in each period. The simplified load curve that has been used for this study is shown in Fig. 3. A demand growth of 6.5% has been considered during the term of planning. The customer price rates are defined in two periods: on-peak and off-peak. The on-peak price is set to be $0.21/kWh and the off-peak price is set at $0.10/kWh [26].

To develop a robust market for distributed resources, there is a need for uniform technical inter-connection standards on a

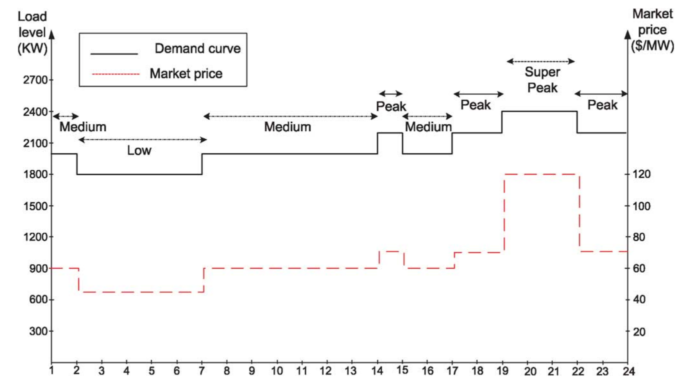

Fig. 3. Approximated daily load and market daily price in the case studies.

TABLE II
CHARACTERISTICS OF DIFFERENT TYPES OF CHP UNITS

System Type	Micro Turbine	Gas Engine	Gas Turbine
Applicable Size (kW)	50-500	500-1000	1000-1500
Heat rate (BUT/kWh)	9,477	9,382	9,605
Recovered Heat (BTU/kWh)	2,748	3,096	3,746
Turnkey Cost ($/kW)	915	690	950
O&M Cost ($/kWh)	0.011	0.009	0.005
Project economic life	10 Years	15 Years	15 Years
Recoverable Heat Used (%)	70%	70%	80%

national or state-wide basis. Currently, there are certain limits in existing standards for connection of DG resources into the distribution networks. Therefore, in our study, the capacity of DGs is assumed to be between 50–1500 kW. The contract term, decided by the DISCO, may take different values between 5–20 years. Without loss of generality, the contract term in this study is assumed eight years, since it is stated in [15] that a payback period of less than eight years is essential for DG penetration. Therefore, we set any NPV_{DG_i} after eight years to be positive to attract investment. It is assumed that DGs can benefit from standard power purchase agreements afterwards.

We assume that the DG technologies in the system operate as CHP units. The non-renewable DGs are often not efficient enough to make the project economical unless the process heat can be captured and re-used. Recoverable heat is valued at the cost of natural gas delivered to end-users. Only the least-cost DG technologies capable of operating at base-load are considered. The CHP technologies are divided into three classes based on application size: 50–500 kW, 500–1000 kW, and 1–1.5 MW. The characteristics of these classes are depicted in Table II [15]. The current tariff provides the buyer with the right to terminate service if seller has not achieved operation in 18 months from the execution date [27]. This requires the commercial operation of units to be less than 18 months. In this work, for gas engine and gas turbine units, a rough installation lead time of 12 months is assumed. For micro-turbine units, the installation lead time is assumed insignificant.

The weekly average natural gas spot prices in California for the fourth quarter of 2009 are used from [28]. The DG penetration and offered prices are obtained with different gas prices in the range of $3.5–6/MMBTU. The average daily value of energy in this study was considered $65.8/MWh; while the hourly

TABLE III
DGs Optimal Sites, Generating Levels, and FiT Prices in Each Period in Scenario I With $3.5 for the Gas Price

DG Bus	P_{DG} (kW)		C_{offer} ($/kWh)		NPV_{DG}
	on-peak	off-peak	on-peak	off-peak	
720	700	655	0.065	0.060	57770
708	900	800	0.065	0.060	57988
741	400	345	0.0723	0.060	235

TABLE IV
Comparison of the Solutions With Different Gas Prices

Fuel cost	Generation Levels(kW)		offered prices(¢/kWh)	
$/MBTU	on-peak	off-peak	on-peak	off-peak
3.5	700-900-400	655-800-345	6.5-6.5-7.2	6.0-6.0-6.0
4.5	700-900-400	655-800-345	7.08-7.3-9.06	6.0-6.0-6.0
6	800-700	800-658	7.62-7.34	7.0-7.03

values vary in the range of $45–120/MWh from the low period to super-peak period. The off-peak period consists of the low and medium load periods and the on-peak period consists of the peak and super-peak periods. The minimum offered price MPR to DG facilities is set to $0.06/kWh for off-peak periods and $0.065/kWh for on-peak periods.

Given the above simulation setups, next we obtain the optimum sizes, sites and prices in two scenarios. First, we obtain the optimum solution considering all the introduced constrains. Second, for a better understanding of the results, a hypothetical case is studied where the DISCO's investment costs and voltage profile limits are neglected.

A. Simulation Scenario I

In this scenario the results of best locations, capacities and generating level in each period with the optimum price tariffs are obtained, taking into consideration *all* the constraints that we introduced in Section II. The impact of an increase in spot gas prices and bilateral contracts are also studied. First, we assume that the gas price for DGs is $3.5/MMBTU. The results for best locations, generating levels in different periods and the prices are shown in Table III. The locations of DG units are also depicted in Fig. 2. We can see that the offered price for the first two units is set to the minimum allowable value MPR. However, for the third unit with a relatively smaller capacity, the offered price needs to be more than MPR to maintain investment economical. The first two units are of type-2 with lower investment and maintenance costs where the generation can be still economical with lower FiT prices. Here in this scenario, the average cost of energy procurement from DG units is lower than the market price; therefore, the DISCO tends to utilize the DGs as much as possible. The total optimal NPV_{DISCO} in this scenario becomes $3 372 600.

Next, we show the impact of an increase in gas prices on the optimal solution in Table IV. Note that gas price have significant effects on both DGs' and DISCO's profits, since higher gas prices increase the cost of generation. When the price increase from $3.5 to $4.5, the optimal choice of locations and generating levels do not change. However, the offered prices in on-peak period has to increase in order to maintain NPV_{DG_i} positive for all DGs. Note that the DGs' profits are notably lower when the gas price is $4.5, compared to when the gas price is $3.5. However, we can see that the average cost of DGs' energy procurement is still slightly lower than the market price. Therefore, the DISCO still benefits from utilizing DGS and we have $NPV_{DISCO} = \$3\,230\,300$.

Next, consider the case where the gas price increases to $6. Clearly, this will lead to a major increase in the generation cost and will require a significant increase in the offered price of electricity to maintain DG investment economical. However, in this case, the average cost of DGs becomes higher than the market price. This makes the DISCO less interested in distributed generation, which results in decreasing the total amount of DG capacities. Note that NPV_{DISCO} in this case is $2 956 800 and the DISCO investment cost is $87 893. If the DISCO were to use no DG, the corresponding NPV_{DISCO} would become $3 003 000 with DISCO investment cost of $200 026 which is still higher than the profit gained by DISCO from utilizing DGs. However, to avoid the installation of a new transformer with the capital cost of $50 000 and to prevent the technical difficulties related to transmission injected power limit and voltage profile, the DISCO decides not to procure the power solely from the market. In this case, in order to maintain the DG investment profitable in presence of the minimum offered prices, the multiple local generation units have to be merged into fewer but bigger units. For this purpose, the algorithm optimally increases the capacity in bus 741 to a larger unit and disconnects one of the DGs from bus 720.

Next, we show the impact of the start date of the projects on the net profits of both DG units and the distribution company. So far, we have assumed in the numerical studies that the DGs start generation right after their installation time has completed. Now we consider four cases when the start dates of the DG projects are postponed. In Case 1, all units are installed in the first year and depending on the project installation time, they start generation in the first or the second year. In Case 2 and 3, we assume that the installation of the second unit is postponed one year and two year, respectively. We also consider another case where the generation of the smallest unit is postponed for two years. We can see in Fig. 4 that the net profit of the DG units decrease as they delay the start time of the project, and with the same offered prices, considering the time value of cash flows and relatively high interest rate, the projects will not remain profitable. However, postponing the DG projects start time may serve the DISCO in terms of net profit, depending on the average purchase price to be offered by the DG unit. We can see that the profit of DISCO from postponing the start time of the largest DG unit decreases, while the profit rather increases when the generation time of the smallest unit with a higher purchase price is delayed.

Finally, the optimum solution for the case that a portion of DISCO's required energy is procured through bilateral contracts is shown in Table V. The capacity to be procured through bilateral contract is 800 kW with the price of $0.065/kWh. We can see that the NPV_{DISCO} in this case is still higher than the case where all energy is procured from the market. However, the total amount of DG's generation capacity decreases in this case

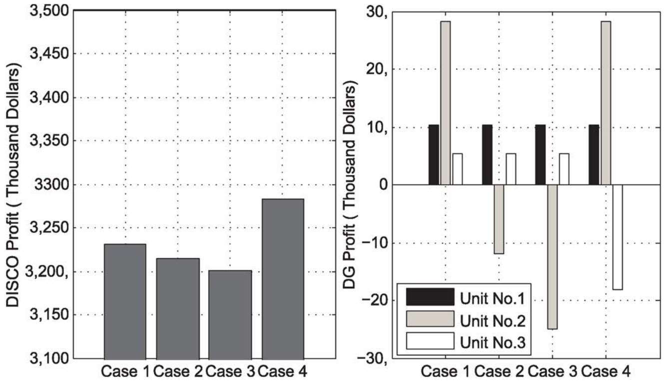

Fig. 4. Impact of project start time on the DISCO's and the DGs' profits.

TABLE V
OPTIMAL SOLUTION OF DG SITES AND SIZES WITH 800 kW BILATERAL CONTRACT AND $3.5 GAS PRICE

DG Bus	P_{DG} (kW)		C_{offer} ($/kWh)		NPV_{DG}
	on-peak	off-peak	on-peak	off-peak	
708	800	650	0.065	0.060	27,786
741	400	350	0.0717	0.060	141

TABLE VI
COMPARISON OF PROFITS WITH AND WITHOUT BILATERAL CONTRACT

Bilateral Contract	NPV_{DISCO}	$Sum(NPV_{DG_i})$	NPV_{total}
0	3,372,600$	115,993$	3,488,593$
800 kW	3,301,820$	29,060$	3,330,880$

as well as their associated profits since the DISCO has to obtain the power from the network. The results on NPV_{DISCO} as well as the summation of NPV_{DG_i} for all DGs *with* and *without* bilateral contract is shown in Table VI. We also see that NPV_{DISCO} decreases in presence of bilateral contracts compared to the case with no such contracts, where more energy is procured from DGs. In this case, although the bilateral price is less than market average price, less power is procured from the DGs with an average price of less than $0.065. Moreover, since the total power to procure from DGs has decreased, the DISCO has offered higher prices in bus 741 in order to maintain the investment attractive, causing an increase in the average price of energy procurement from DGs.

B. Simulation Scenario II

The second scenario is defined by removing the network upgrade costs and voltage profile limits from the optimization problem formulation such that the design objective becomes limited to just finding the allocation that best suits DISCO with minimum power procurement cost. Our intention to study Scenario II is to gain insights with respect to the *prominent factor* in choosing the optimal allocation. Thus, the results here compliment those already obtained for the case of Scenario I.

The optimization results for the case of Scenario II are shown in Table VII. The number of units has been decreased to two such that we can integrate more power generation to be able to procure power with lower prices. Furthermore, by increasing

TABLE VII
DGS OPTIMAL SITES, GENERATING LEVELS, AND FIT PRICES IN EACH PERIOD IN SCENARIO II WITHOUT DISTRIBUTION INVESTMENT COSTS

DG Bus	P_{DG} (kW)		C_{DG} ($/kWh)		NPV_{DG}
	on-peak	off-peak	on-peak	off-peak	
720	1000	1000	0.065	0.060	107,880
734	1000	800	0.065	0.060	29,218

the generation level of unit-2, the DG has been moved upward to prevent the flow back of current. We can see that the DISCO utilizes the DGs in the off-peak period despite the fact that the average market price in this period is lower than the MPR. Note that the increase in the generation levels are indeed required in order to decrease the on-peak price of DGs such that we can maintain NPV values positive. In other words, since a DG unit with on-peak period generation cannot maintain economical with $0.065/kWh; the DISCO should also procure the power from DGs in off-peak period with a loss of about $0.005/kWh so that it can purchase the power in the on-peak period with a profit about $0.0237/kWh. In this way, DISCO procures more overall power at less overall price.

The results in this section show that apart from the capacity release benefits that DISCO may have from utilizing DGs, a proper choice of DG size and offered price can lead to increased benefits for DISCO in procuring the energy. This factor motivates the DISCO to merge the DG units into bigger sizes to make it possible for lower prices for energy procurements. However, network constraints and network upgrade costs motivate the DISCO to distribute the DG units. The combination of these competing factors leads to an optimal trade-off between the size and offered price which is achieved using the proposed optimization-based algorithm.

V. CONCLUSION

In this paper, a novel optimization-based approach is presented to determine the best sites, generation levels in different periods of time, and the feed-in-tariff incentives in distributed generation systems. The design goal is to maximize the DISCO's profit while maintaining investment attractive for each individual DG owner. A detailed economical model was proposed that takes into account different factors related to the DISCO's and DGs' profits, including gas price and the total MW of bilateral contracts. A differential evolution algorithm is proposed to effectively solve the formulated optimization problem. The performance of algorithm is verified in various cases. Simulation results show that despite the lower value of average market price in off-peak period, if the DG sites, sizes, and prices are allocated optimally, the DISCO can utilize and coordinate the DGs to gain more profit compared with purchasing the power only from the grid, while the DGs can assure positive profits and attractive investments.

The results in this paper can be extended in several directions. First, given the observation that some factors, such as gas price, may change the optimal solution for DG sizes and offered prices, the models can be adjusted to incorporate the presence of such risks to maximize the profit with minimum risk. Second, the DG units considered in this paper are of committed types. However, it is likely that a DG unit has a forced outage;

therefore, the costs that DISCO might incur from loss of load in these conditions need to be further investigated. Finally, integrating renewable DGs in the proposed optimization framework remains as an interesting open problem.

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