# Analysis of Factors Influencing Photovoltaic Generators Optimal Installation in Distribution Network

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**Abstract:** The installed capacity generation and the load distribution effects on the optimal location and sizing of photovoltaic generators in the distribution network are analyzed in this article. A genetic algorithm estimates the optimal location and sizing of photovoltaic generators. The calculation of the feeder annual energy losses, which are the objective function of the optimization problem, is performed by the backward/forward method. The complete feeder's annual active load duration curve is segmented into three levels. It is assumed that the load curves in all buses are identical to the feeder and the irradiance and ambient temperature are invariant to the average value for each load level. The analysis is based on scenarios created for a 69-bus test system.

**Keywords:** Photovoltaic generation, optimum siting, genetic algorithm, distribution network, distributed generation

## 1. Introduction

Among the many advantages of using photovoltaic (PV) generation, perhaps the main one is its low environmental impact energy source. Moreover, growing concern about the environment makes solar energy more and more evident both in the academic and commercial spheres. As a result, the share of solar photovoltaic generation in the world energy matrix is gradually increasing over the years, despite the difficulties faced by the northern hemisphere countries with long and rigorous winters. Consequently, there is insufficient solar incidence at some times of the year.

Besides being a low environmental impact energy source, photovoltaic generation has other advantages. It reduces technical losses, emission of pollutants, voltage profile, and power quality improvement and increases energy efficiency (Kazemi and Sadehi, 2009). However, according to Prakash and Kathod (2016), installing photovoltaic units in inappropriate places can lead to instability problems, and bidirectional power flow can lead to system protection issues. This can be avoided by using optimization techniques to determine appropriate locations and sizing of the generators.

The distributed generation optimization topic is not new. Nevertheless, it remains contemporary, increasing, and renewed interest due to the great importance of photovoltaic generation in recent years. In optimization problems, load and generation are always considered constant, have models based on probability distribution functions, or have complicated models. In this work, we use a model that considers the variation of load and generation in a simple way but is suitable for optimization studies in distribution networks.

The problem of optimum location and sizing of distributed generation has already been solved in different ways. Borowy and Salameh (1994) use irradiance and wind velocity hourly data to determine the probability distribution function of the irradiance and wind velocity for each hour of a typical day in a month. The authors use this information to find the best size of a hybrid system to meet load demand. This approach is likely to be computationally very expensive. Haesen et al. (2005) utilize a genetic algorithm to locate and size distributed generation units in a residential distribution grid with the objective of power loss minimization. The optimization is based on a 24-hour analysis of generation and load demand; this is not highly recommended as the variation in load and generation is very high throughout the year. Similarly, Moradi and Abedini (2012) also propose a method to locate and size distributed generation units to minimize power losses, employing a hybrid of genetic algorithm and particle swarm optimization algorithm. Khatod, Pant, and Sharma (2013) present an evolutionary programming technique for optimal placement of solar and wind generation units considering the stochasticity of the variables. Abdelaziz et al. (2015) solve the problem of optimal location and size of renewable energy distributed generators with a sequential Monte Carlo simulation with a modified Big Bang-Big crunch algorithm to minimize energy losses. Liu et al. (2015) present a method for optimal sitting and sizing of distributed generation in distribution systems to reduce costs and consider the minimum voltage deviation. To do so, an improved Non-dominated Sorting Genetic Algorithm II is utilized. Ahmed et al. (2020) use a particle swarm optimization algorithm for optimal placement and sizing of wind generators to minimize the average multi-objective index composed of active and reactive power losses, voltage deviation, and voltage stability.

Although several authors have already studied the problem of optimal allocation of distributed generation, the topic is not exhausted and continues to deserve attention. The aim of this work is to verify the influence of the load demand distribution and the possible installed capacity of the distributed generation on the optimal location and sizing of the PV generation to reduce energy losses.

This article, which covers a continuation of the research presented in Alencar et al. (2018), is structured as follows. In section II, the problem is stated, and the load and generation models are presented; Section III describes the objective function of the problem; The stopping criterion is indicated in section IV; The application of the methodology is presented in section V; In section VI the results are analyzed, and section VII presents the conclusions.

**2. Problem statement**

The topic addressed in this article is to employ the photovoltaic generator location method proposed in Alencar et al. (2018) and conduct studies on some factors that influence the optimal installation of the photovoltaic generator. Therefore, a determined number of load levels are set by segmenting the annual active load duration curve of the complete feeder, lifted at the substation output. Then, the irradiance duration curve is segmented from the time intervals in which each load level remains at the same value. Thus, initially, the problem is to minimize:

$$\Delta E = \sum_{j=1}^{m} T_j \sum_{k=1}^{n} \Delta P_{j_k}, \tag{1}$$

where:

| | |
|---|---|
| $n$ | number of feeders sections; |
| $\Delta P_{j_k}$ | active losses on section *k*, which ends at the bus *k* at load level *j*; |
| $m$: | number of levels at which the load duration curve is segmented; |
| $T_j$ | duration of the load level *j*; |
| $\Delta E$ | annual energy losses. |

The total active power losses $\Delta P_j = \sum_{k=1}^{n} \Delta P_{j_k}$ are the result of the load flow calculation, for which the backward/forward sweep method from Cheng and Shirmohammadi (1995) is used repeatedly for the load levels.

The following considerations are made:

- The generators are in pre-set number.
- Solar irradiance and ambient temperature are typical of each load level and do not vary from one point to another within the feeder range.
- One and only one photovoltaic generator can be installed on any feeder bus.

**The load and generation models**

The available information on the feeder buses usually is the installed loads, $\dot{P}_k$. The mean demand on the bus *k* (*k*=1, 2, ..., *n*) is estimated from the installed load $\bar{P}_k$, the *demand factor* δ, and the *load factor* λ of the complete feeder whose expressions are:

$$\delta = \frac{\hat{P}}{\sum_{k=1}^{n} \dot{P}_k} \quad \textbf{(2)}$$

and

$$\lambda = \frac{\hat{P}}{\bar{P}}, \quad \textbf{(3)}$$

$\bar{P}$ and $\hat{P}$ are the mean and peak values in the feeder, taken from the load curve lifted at the substation output.

Assuming, in a simplified way, that the load curves in all the buses follow the feeder load curve, the mean installed load power in bus *k* is determined by the following expression:

$$\bar{P}_k = \delta\, \lambda\, \dot{P}_k. \quad \textbf{(4)}$$

For a better representation of the load variation in time, the feeder annual load duration curve is divided into *m* intervals to have a mean power value at bus *k* (*k* = 1, 2, …, *n*) for each load level *j* (*j* = 1, 2, …, *m*):

$$\bar{P}_{j_k} = \delta_j \lambda_j \dot{P}_k, \quad \textbf{(5)}$$

where:

$$\delta_j = \frac{\hat{P}_j}{\sum_{k=1}^{n} \dot{P}_k}, \quad \textbf{(6)}$$

$$\lambda_j = \frac{\hat{P}_j}{\bar{P}_j}, \quad \textbf{(7)}$$

$\hat{P}_j$ is the peak value and $\bar{P}_j$ is the mean value at the load level *j* (*j* = 1, 2, …, *m*).

**Identification of load levels**

Solar irradiance is a nondeterministic temporal process and, in some applications, is modeled by a probability distribution function.

For this work's purpose, the same irradiance and ambient temperature values are considered in all distribution network influence areas. Furthermore, it is also assumed that the irradiance and ambient temperature values do not deviate from the respective mean values relative to the moments where the load is of a certain level.

Since the study was done with northeastern Brazil data, solar radiation occurs from dawn to dusk, i.e., 10 to 12 hours of the 24 hours of the day. Therefore, the generators produce electricity only a fraction of $\alpha$ ($0.4 \le \alpha \le 0.5$) of the load duration, whatever the level.

**Photovoltaic output power**

The photovoltaic output power depends on the local solar irradiance, ambient temperature, and module characteristics. Thus, the output power is calculated by (Teng et al., 2013):

$$P_o(s) = N \cdot FF \cdot V \cdot I, \quad \textbf{(8)}$$

where:

$$FF = \frac{V_{\mathrm{MPPT}}\, I_{\mathrm{MPPT}}}{V_{\mathrm{OC}}\, I_{\mathrm{SC}}}, \quad \textbf{(9)}$$

$$t_c = t_A + s\left(\frac{N_{\mathrm{OT}} - 20}{0.8}\right) \quad \textbf{(10)}$$

$$V = V_{\mathrm{OC}} - K_v\, t_c \quad \textbf{(11)}$$

$$I = s[I_{sc} + K_i(t_c - 25)] \quad \textbf{(12)}$$

where $t_c$ and $t_A$ are the photovoltaic module and ambient temperatures, respectively. $N_{OT}$, $I_{SC}$, and $V_{OC}$ are the nominal operating temperature, the short-circuit current, and the open-circuit voltage of the PV module, respectively. $K_v$ and $K_i$ are the voltage temperature coefficient and the current temperature coefficient, respectively. □□ is the fill factor. *s* is the solar irradiance in kW/m². *N* is the number of modules used in the system. □□□□□and □□□□□ are the current and voltage at the maximum power point. □□is the photovoltaic output power and is a function of the irradiance and ambient temperature variables.

### 3. The objective function

The distribution network energy losses were initially considered as (1). However, the generators only operate a fraction of the load duration at any level, so (1) is best written as

$$\Delta E(h_1, \ldots, h_g) = \alpha \sum_{j=1}^{m} T_j \sum_{k=1}^{n} \Delta \hat{P}_{j_k} + (1-\alpha) \sum_{j=1}^{m} T_j \sum_{k=1}^{n} \Delta \check{P}_{j_k}, \quad \textbf{(13)}$$

where *g* is the number of photovoltaic generators, □□ (□ = *1*, *2*, . . . , □) is the bus where the *i*-th generator is installed, $\Delta\hat{□}_{j_k}$and $\Delta\check{P}_{j_k}$are the active losses at section *k* at load level *j* with and without photovoltaic generation, respectively.
Since the second part of the energy losses expression is not a function of the control variables (□ *1*, . . . , □□), it can be dismissed for optimization purposes. Therefore, the fitness is effectively the following:

$$\xi(h_1, \ldots, h_g) = \sum_{j=1}^{m} T_j \underbrace{\sum_{k=1}^{n} \Delta \hat{P}_{j_k}}_{\Delta \hat{P}_j} \quad \textbf{(14)}$$

The calculation of the distribution network energy losses requires power losses calculation routine to be executed several times equal to the established load levels. In addition, these calculations need to be redone whenever the buses on which the PV generators are cogitated to be installed change. Fig. 1 is the complete and general procedure adopted for the photovoltaic distributed generation optimization.

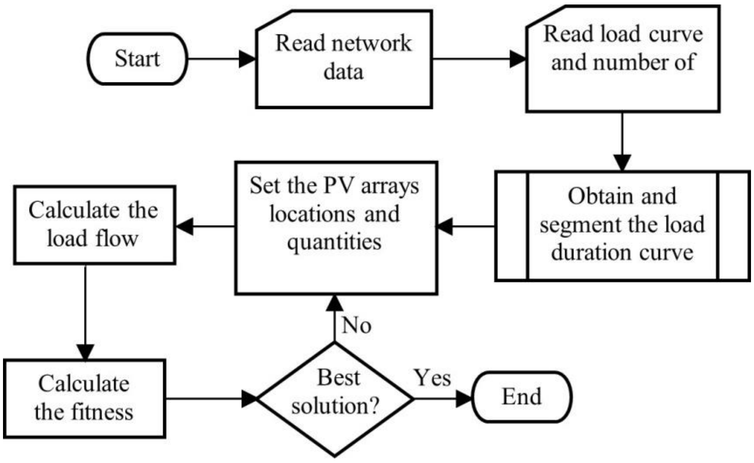


**Figure 1 Procedure used to locate and size the PV generators optimally.**

### 4. Stopping criterion

As a stopping criterion of the optimization method, any individual fitness dispersion measure concerning the population's average fitness value can be adopted. However, a disadvantage of measures such as the mean or standard deviation is that they are not normalized. For this reason, the population *homogeneity index* is preferred, which is expressed as follows:

$$\eta = 1 - \frac{\sum_{i=1}^{n} |\xi_i - \bar{\xi}|}{n\bar{\xi}} \quad \textbf{(15)}$$

Where $\bar{\xi} > 0$ and $\xi_i$ is the fitness of the individual $i$ ($i$ =1, 2, …, $p$). The homogeneity index has a normalized value: the more different the fitness of individuals, the lower the index value. When they are all the same value, $\eta = 1$.

## 5. Methodology application

### Data and hypotheses

Generators can be installed on any feeders' buses except the substation bus, where it would not affect loss reduction. The photovoltaic module data were taken from Teng et al. (2013). It is considered that 1000 modules form a PV array.

The load curve survey was performed using hourly data from a local energy distribution company substation. The data sorted in descending order results in the annual load duration curve. Fig. 2 shows that three load levels were considered for optimal segmentation of the load duration curve. Another number of load levels could be considered for the segmentation, with more levels implying more results accuracy. The numeric values used on each load level are shown in table 1.

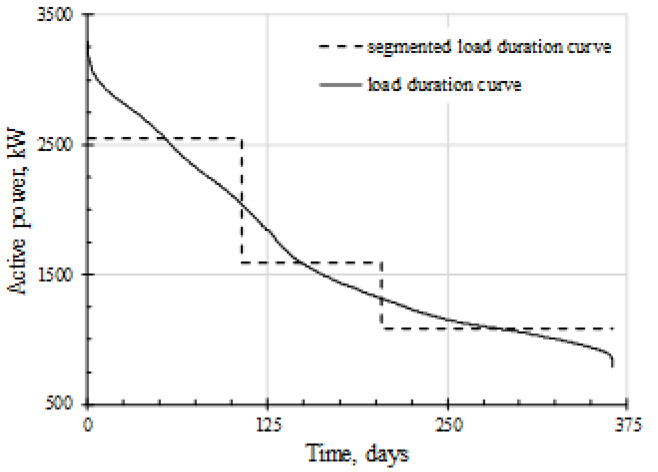


Figure 2 Load duration curve.

**Table 1: Feeder load levels**

| Load | Duration, days | Demand, kW medium | Demand, kW maximum | Demand factor | Load factor |
|---|---|---|---|---|---|
| **Heavy** | 107.2 | 2550 | 3294 | 0.929 | 0.774 |
| **Medium** | 97.2 | 1595 | 2035 | 0.574 | 0.784 |
| **Light** | 160.1 | 1089 | 1315 | 0.371 | 0.828 |

Solar irradiance and ambient temperature are considered to have the same value within the feeder range and do not change as long as the load remains at a certain level. Therefore, these data are used by their mean values for each load level and are in table 2.

The mean irradiance for each load level is effective. In the calculation, zero, residual or non-measured values are excluded. Thus, it was observed that photovoltaic generation occurs for each load level in 12/24 of its duration (α = 50%).

**Table 2: Irradiance and ambient temperature averages**

| **Load** | $\bar{s}$,□ $/m^2$ | $\bar{t}_□$ °C |
|---|---|---|
| **Heavy** | 538.7 | 28.1 |
| **Medium** | 495.9 | 26.0 |
| **Light** | 308.0 | 23.8 |

**Test system**

The optimal location and sizing of photovoltaic generators for four different scenarios are taken as a problem to be solved by the method proposed in Alencar et al. (2018) and employed here. Fig. 3 shows the IEEE test feeder configuration with a nominal voltage of 12.66 kV.

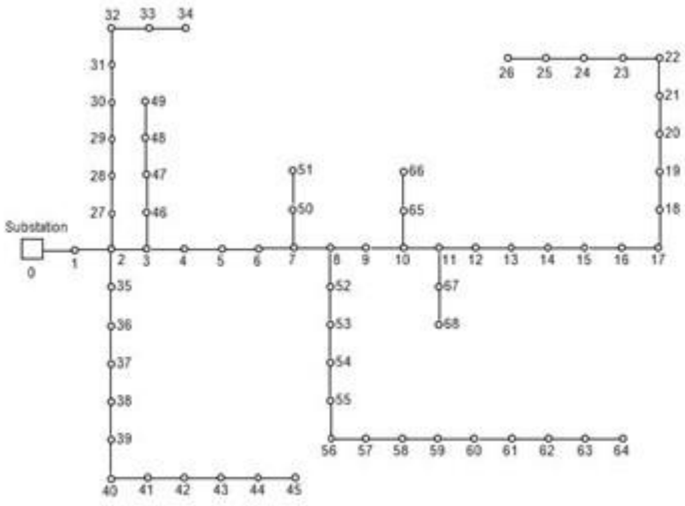


**Figure 3. The 69 bus test system.**

The installation of four PV generators was solved based on the following assumptions:

1. Photovoltaic module data: □$_{□□}$: 43 °C, □$_{□□□□}$: 7.76 A, □$_{□□□□}$: 28.36 V, □$_{□□}$: 8.38 A, □$_{□□}$: 36.96 V, □$_{□}$: 0.00545 A/°C, □$_{□}$: 0.1278 V/°C.
2. A PV array is composed of 1000 PV modules.
3. Regarding the genetic algorithm:
   - Chromosomes with decimal representation, a possible solution being the chromosome shown in fig. 4. In this solution, generators □$_1$,□$_2$,□$_3$,□□□ □$_4$composed of 2, 5, 3, and 10 PV arrays would be installed in buses 9, 15, 25 and 45, respectively.
   - Population size and the number of generations equal to 100.
   - Crossover rate of 40%.
   - Mutation rate equal to 2%.
   - Tournament selection.
   - Number of generations or population homogeneity as stopping criteria, and a population is considered homogeneous if its homogeneity index is 0.99.
4. The solar irradiance and ambient temperature are characteristic of each load level, according to table 2.

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 9 | 15 | 25 | 45 | 2 | 5 | 3 | 10 |
| positions of the generators | | | | compositions of the generators | | | |

**Figure 4. The decimal representation of a chromosome.**

**Case studies**

Four case studies are performed to investigate whether there is a significant influence of (i) installed power of the generators and (ii) installed loads distribution in the system on the optimal location of photovoltaic generators. The four case studies are:

Case I. It is the base case, in which the installation of four PV generators formed by a total of 20 PV arrays occurs in the original test system, that is, without modifying the load.

Case II. The second case study is installing a maximum of 40 PV arrays in the original test system.

Case III. In this case, the influence of the installed load distribution is investigated. The system's total active and reactive loads remain the same as those of the base case but are more concentrated on segments 8 - 9 - 10 - 11, which are the system's most central buses. The number of PV arrays is the same as in case I.

Case IV. The last case study has the number of arrays equal to case II, and the system is the same as in case III.

**6. Results and analysis**

The optimal installation of four photovoltaic generators in a 69-bus test system and a nominal voltage of 12.66 kV was investigated through the methodology presented in section III and case studies presented in the previous section. The feeder energy losses without photovoltaic generation are 922.89 MWh/year.

**Case I**

For this case, the global best solution to the problem is to install 5, 2, 5, and 8 PV arrays on buses 61, 62, 63, and 64, respectively. As a result, energy losses are reduced to 811.5 MWh/year, which corresponds to a reduction of 12.07%. Fig. 5 shows the system after the installation of photovoltaic generators.

**Case II**

In this case, the amount of PV arrays to be installed is doubled with reference to the case I, and the installation is still made in the original system. The optimal solution remains the positioning of the generators at the end of the same feeder branch in which the generators were installed in case I, with a variation of only one bus. The optimal solution is to install 7, 19, 10, and 4 PV arrays on buses 60, 61, 63, and 64, respectively. As a result, losses are reduced to 735.83 MWh/year, or 20.27% of energy losses. Fig. 6 is the system configuration for this case.

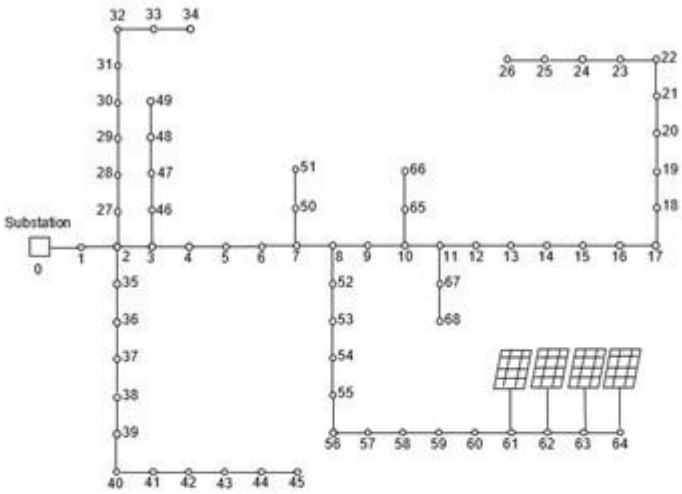


Figure 5. Results of case I.

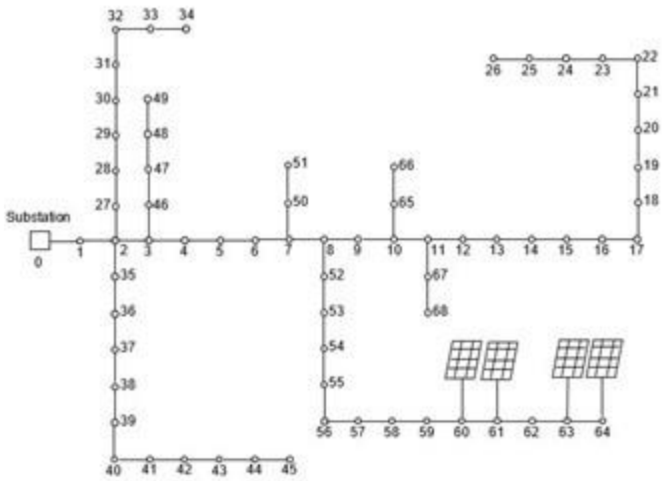


**Figure 6. Results of case II.**

**Case III**

The system loads were rearranged in such a way that total active and reactive loads remained the same as the original system. However, with the rearrangement, they are more concentrated in the middle of the system, and thus it is possible to verify if the result differs from the cases previously analyzed. The procedure for modifying the initial load was to reduce it on each system section to 10% of its original value. The difference between the original and modified total load was divided into three system buses.

The modified test system has energy losses equal to 1087.5 MWh/year. For this system, the global best solution is to install 6, 5, 4, and 5 PV arrays on buses 11, 12, 13, and 67, respectively. Thus, energy losses become 1004.7 MWh/year, a reduction of 7.61% in losses, showing that the higher the concentration of loads at a given point in the system, the smaller the influence of distributed generation on the energy losses reduction. Fig. 7 is the distribution system after the installation of the generators.

 

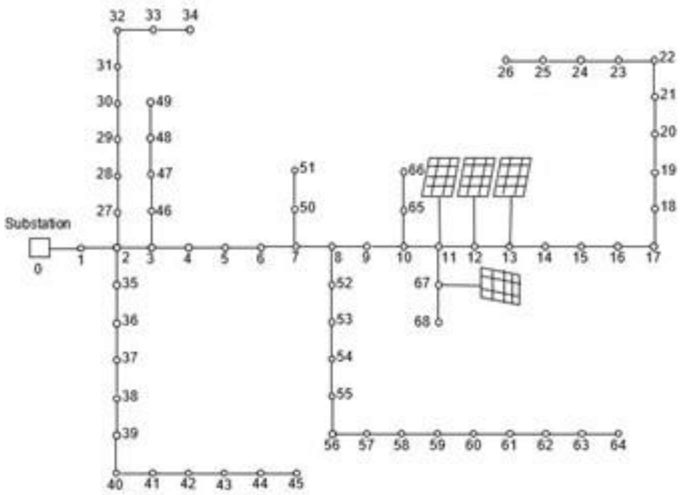


Figure 7. Results of case III.

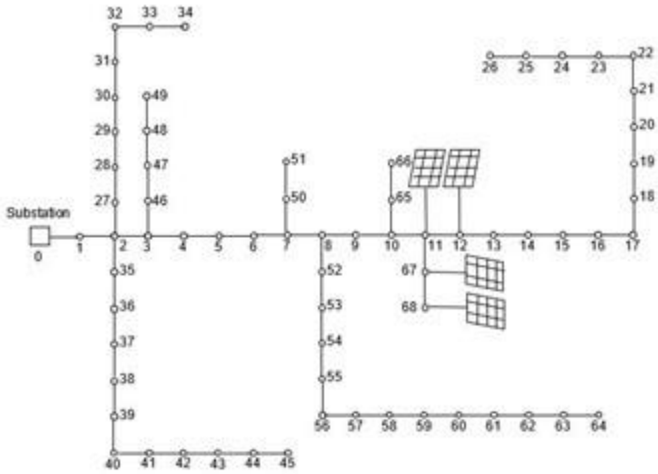


**Figure 8. Results of case IV.**

**Case IV**

Now, the system of case III is studied with the photovoltaic generation of case II. For this case, the optimal location of the generators is similar to case III, i.e., install 15, 9, 8, and 8 PV arrays on buses 11, 12, 67, and 68, respectively. In this context, energy losses become 942.28 MWh/year, a reduction of 13.35% in annual losses. Fig. 8 shows the system after the installation of the generators. The summarized results of the case studies are in table 3.

**Table 3: Case studies results.**

| Case | Increased load buses | System buses to install PV arrays | Number of PV arrays | Energy loss reduction |
|---|---|---|---|---|
| **I** | - | 61 - 62 - 63 - 64 | 5, 2, 5, 8 | 12.07% |
| **II** | - | 60 - 61 - 63 - 64 | 7, 19, 10, 4 | 20.27% |
| **III** | 8 - 9 - 10 - 11 | 11 - 12 - 13 - 67 | 6, 5, 4, 5 | 7.61% |

| | | | | |
|---|---|---|---|---|
| **IV** | 8 - 9 - 10 - 11 | 11 - 12 - 67 - 68 | 15, 9, 8, 8 | 13.35% |

**Analysis of results**

From the case studies, the most significant influence on the generator's location is given by the installed load distribution in the system. Cases I and II shows that despite the increased number of PV arrays, their locations remain unchanged. However, from the moment the system installed loads are predominantly concentrated in three middle sections of the feeder (case III), the generators' locations changed drastically even if the installed power is the same as in case I. Finally, case IV ratifies the claim that increasing photovoltaic generation does not significantly change their location.

**Conclusions**

An analysis of two factors that may influence the optimal location and sizing of photovoltaic generators in the distribution network was performed. These factors are the installed power of photovoltaic generators and the load distribution in the system.

A genetic algorithm was used to solve the optimization problem to minimize annual energy losses. The problem's solution was found considering the segmentation of the load duration curve at three levels and assuming that solar irradiance and ambient temperature are invariant at each load level.

The methodology was applied to the 69-bus test system through case studies, in which four generators were sized and positioned in different feeder buses. In addition to the original test system, three other cases were analyzed to verify the influence of the installed loads and photovoltaic generators' power. It was found that the system load distribution significantly influences the generators' location more than their installed power.

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