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An elegant emergence of optimal siting and sizing of multiple distributed generators used for transmission congestion relief

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Abstract: After the implementation of deregulation in a power system, an appreciable volume of renewable energy sources is used to generate electric power. Even though they are intended to improve the reliability of the power system, the unpredictable outages of generators or transmission lines, an impulsive increase in demand, and failures of other equipment lead to congestion in one or more transmission lines. There are several ways to alleviate this transmission congestion, such as the installation of new generation facilities in the place where the demand is high, the addition of a new transmission facility, generation rescheduling, and curtailment of load demand processes. Among the above methods generation rescheduling and load shedding are normally preferred, since the other methods require additional investments. However, some critical cases require improved methods to alleviate congestion. With the extensive application of distributed generation (DG), congestion management is also accomplished by the optimal placement of multiple DG units. It is well known that incorrect sizes and improper locations of DG undoubtedly create higher power losses and an undesirable voltage profile. Hence, this research effort employs the line flow sensitivity index to establish the optimal location of DG units and genetic algorithm-based optimization for determining the optimal sizes of DG units. The objective of this research is to minimize the total losses and real power flow performance index and to improve the voltage shape of the modified IEEE 30-bus test system. The results of this proposed approach are encouraging and help in anticipating higher efficiency by satisfying all the objectives.

Key words: Transmission congestion, real power flow performance index, line flow sensitivity index, distributed generation, genetic algorithm

1. Introduction

Energy technologies play a vital role in the socioeconomic development of any country. Besides their welfare effects, they also cause environmental pollution and degradation. It is obvious that nonrenewable fossil fuel dependency for energy requirements is the major cause of pollution and climate change. Exploration of sustainable alternatives for future energy needs is becoming increasingly essential due to the dwindling energy resources. In recent years, restructuring of the electricity market has brought some major improvements in energy production technologies and thus paved the way for the increased usage of distributed generation (DG) with renewable energy resources. Hence, the conventional pattern of electricity generation, transmission, and

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consumption is being slowly replaced by DG units. The definition for DG is small generators connected within a distribution network, located either nearer to the customer or a remote site. It is expected that the penetration level of DG will cover 25% of total demand in the next 10 years worldwide [1].

DG units in distribution networks result in some constructive impacts such as improvement of voltage level and power quality, and reduction of total loss. The notable negative impact is the fault current increase and the disturbance in relay coordination of the protective system. The verdict of optimal location and capacity of DG units is the most important one, since all the impacts are reliant on the type, capacity, and placement of DG resources.

Presently, an immense volume of research papers are available to address the optimal siting and sizing of DG units; nevertheless, most of them are deterministic methods [2–10]. Analytical methods are presented to determine the optimal location of DG in radial and networked systems with the objective of minimization of the losses [3]. A methodology with some restricted constraints evolved by the use of linear programming to find out the optimal allocation of embedded generation [4]. The genetic algorithm (GA)-based approach was presented to establish the optimal placement and sizing of multiple DG units with the objectives of loss reduction and voltage profile improvement in distribution systems [5].

An easy but conventional search technique is combined with Newton–Raphson load flow for finding the optimal placement of DG [6–8]. However, the objective is used to find the optimal location of DG without considering the size of DG. An equivalent current injection-based loss sensitivity factor with the objective of minimizing total power losses is used to determine the optimal locations and sizes of DG units [9]. A new approach was proposed to optimally determine the locations and sizes of DG units in a large mesh-connected system [10].

After the implementation of deregulation, the companies that are in power generation and distribution accomplish the business of electric power. Even though the overall trustworthiness is improved by the interconnection of a power system, it also causes undesirable overcrowding, called congestion, in transmission lines. Transmission line congestion is among the major key issues in deregulated power scenarios. Congestion occurs whenever one or more constraints of the system get violated, below which the system operates in the normal state. The violations of constraints usually exceed the limits of operating parameters like thermal parameters, voltage parameters, and some specified limits that are assigned to ensure system security and reliability [11].

The system returns to its safe state if transmission congestion is relieved by some means. Mainly two types of techniques are used to relieve congestion, as listed below.

1. Methods that do not consider cost

   This includes the outaging of congested lines, inclusion of transformer taps, phase shifters, and placement of DG and flexible AC transmission systems (FACTS) devices in distribution and transmission network, respectively.

2. Methods that consider cost

   Redispatch in generator output and load curtailments are in this category.

It was proved that the control of load demand is more effective than the rescheduling of generators for congestion liberation [12]. The particle swarm optimization (PSO)-based method was proposed for finding the optimal generation rescheduling to alleviate transmission line congestion [13]. Even though the above methodology claims simplicity, the line connected with the slack generator does not fully get alleviated from line congestion. The relative electrical distance (RED) initiative is used to optimize the generator rescheduling to relieve congestion [14]. The concept of RED is reliable in identifying the congested lines, but the process of finding relative locations of load nodes with respect to generator nodes is tedious.

A cost/worth analysis is used with the optimal placement and proper sizing of DG for congestion management in reliability test systems [15]. A novel sensitivity-based method was proposed for congestion liberation by promptly allocating DG units. The optimal value of DG units is optimized using a GA with the objective of reducing system losses and sustaining the voltage profile without considering the value of the real power flow performance index of the most severe contingency case [16].

Hence, this research effort identified that there is a research opening in alleviating transmission congestion with the DG units by considering the real power flow performance index value of the most severe contingency case. In this present work, the siting of DG units under severe contingency is proposed for congestion management. It is acknowledged that improper placement of DG units may cause higher power loss and appalling voltage levels. Therefore, this work employs the line flow sensitivity index (LFSI) to determine the optimal location of DG units in a modified IEEE 30-bus test system (for details, see Appendix, on the journal's website).

The remaining portion of this manuscript is ordered as follows. In Section 2, the calculation of real power flow performance index, N-1 contingency measure, contingency grading, and optimal locations of DG units are elaborated. Section 3 gives a brief description about the GA and problem formulations of this research effort. In Section 4, comprehensive simulation results and elaborate discussions are presented. Section 5 illustrates some of the imperative conclusions of this work.

2. Identifying the optimal locations for DG units

The allotment of DG units for the congestion relief using the N-1 contingency measure certainly gives some important solutions against system security threats. Therefore, it is essential to identify the suitable location for the allocation of DG, which could offer an enhanced performance in almost all circumstances.

2.1. Contingency grading

It is obvious that various limit violations occur in power systems, but the most severe and widespread violations are monitored and evaluated promptly to ensure the system security. The precise assessment of severity impact and the adaptation of appropriate corrective measures are the fundamental things to alleviate these problems. The process of this assessment is known as contingency screening.

The general form of real power flow performance index (PI_{RP}) is defined as:

$$[PI_{RP}]^i = \sum_{\substack{allcongested \\ branches}} \left(\frac{w_l}{2n}\right)\left(\frac{P^i_{flowl}}{P_l^{\max}}\right)^{2n} + \sum_{j=1}^{N}\left(\frac{w_j}{2n}\right)\left(\frac{\Delta V_j^i}{\Delta V_j^{limit}}\right)^{2n} \tag{1}$$

$$\Delta V_j^{(i)} = V_j^{(i)} - V_j^{limit}, \tag{2}$$

$$V_j^{limit} = V_j^{\max}, \forall V_j^{(i)} \geq 1.0, \tag{3}$$

$$V_j^{limit} = V_j^{min}, \forall V_j^{(i)} < 1.0, \tag{4}$$

$$V_j^{(i)} = V_j^{\max}, \forall V_j^{(i)} > V_{\max} \tag{5}$$

$$V_j^{(i)} = V_j^{min}, \forall V_j^{(i)} < V_{\min} \tag{6}$$

$$\Delta V_j^{limit} = \frac{V_j^{\max} - V_j^{min}}{2}, \tag{7}$$

where $[PI_{RP}]^i$ is the real power performance index of the ith outage. w_j and w_l are the weighting factors of bus j and line l, respectively, and they are selected by the system operator by considering the operating conditions of the system. P_{flowl}^i is the line flow of the lth line with ith outage, $P_l^{\max}$ is the maximum rating of the lth line, N is the total number of buses in the system, and the term $2n$ represents the order of real power performance index, which is considered as 2.

A variety of credible failures occur during the operating period of power system and this creates a contingency group, and some among them possibly lead to congestion or limit violations for some parameters. The normal state of the power system can easily be recovered if the dangerous contingencies are promptly acknowledged with comprehensive assessment and the application of appropriate remedial actions. Contingency grading is a way of categorizing significant contingencies by ranking based on real power flow performance index values. Different cases are simulated to observe the usefulness of this projected method.

2.2. Finding the optimal location for DG units by LFSI

Rescheduling of generators is normally preferred for alleviating this congestion in most cases, but it is incompatible for some specific cases due to inconsistency and escalation in load pattern. Hence, LFSI-based congestion management is formulated from the overloaded lines. The values of LFSI are calculated by considering the method proposed in [16] and the procedural steps are given as follows:

$$\Delta S_{ij} = \frac{\partial S_{ij}}{\partial P_l}\Delta P_l + \frac{\partial S_{ij}}{\partial Q_l}\Delta Q_l, \tag{8}$$

where ΔS_{ij} is the change in line flow between nodes i and j. The term ΔP_l represents the change in real power injection at the lth node and ΔQ_l represents the change in reactive power injection at the lth node.

It is observed that the response of S_{ij} with respect to reactive power Q_l is minute in contrast to active power P_l. Hence, the reactive power component from Eq. (8) is omitted and it is given as

$$\Delta S_{ij} = \frac{\partial S_{ij}}{\partial P_l}\Delta P_l. \tag{9}$$

If $P - V$ coupling is discarded, Eq. (9) can be tailored as follows.

$$[LFSI]^{l_o} = \left(\frac{\partial |S_{ij}|}{\partial \delta_i}\right)\left(\frac{\partial \delta_i}{\partial P_l}\right) + \left(\frac{\partial |S_{ij}|}{\partial \delta_j}\right)\left(\frac{\partial \delta_j}{\partial P_l}\right) \tag{10}$$

$$|S_{ij}| = (T_{ij})^{1/2} \tag{11}$$

$$T_{ij} = V_i^4 Y_{ij}^2 + V_i^2 V_j^2 Y_{ij}^2 - 2V_i^3 V_j Y_{ij}^2 \cos\delta_{ij} + 2V_i^3 V_j Y_{ij} B_{sh} \sin(\theta_{ij} + \delta_{ij}) - 2V_i^4 Y_{ij} B_{sh} \sin\theta_{ij} + V_i^4 B_{sh}^2 \tag{12}$$

$$\frac{\partial |S_{ij}|}{\partial \delta_i} = T_{ij}^{1/2}\left(V_i^3 V_j Y_{ij} \sin\delta_{ij} + V_i^3 V_j Y_{ij} B_{sh} \cos(\theta_{ij} + \delta_{ij})\right) \tag{13}$$

$$\frac{\partial |S_{ij}|}{\partial \delta_j} = -T_{ij}^{-\frac{1}{2}} \left(V_i^3 V_j Y_{ij} \sin \delta_{ij} + V_i^3 V_j Y_{ij} B_{sh} \cos \left(\theta_{ij} + \delta_{ij} \right) \right) \tag{14}$$

The values of LFSI are calculated for all the load buses by using the above equations from Eq. (8) to Eq. (14). The calculated LFSI values of all load buses are then ranked and arranged in a descending manner. The load buses that have the highest negative values of LFSI are chosen for DG placement, because they show more response to the congested lines. This projected methodology has momentum in continuing to amend the values of LFSI for various outages. Consequently, the selection of load buses for the optimal allocation of the DG units to alleviate the congestion can effectively be realized. Since the optimal location for DG units in order to relieve congestion is successfully accomplished, it is necessary to find the optimal size of the DG units in these favored places.

3. Formulation of problem for finding optimal size of DG units

A GA-based optimization technique is used to evaluate the exact size of DG units in already identified locations [16]. This has been achieved with the objective of enhancing the performance characteristics of the system. The core intention of the above work involves a reduction of real power losses and an increase in the voltage profile of the system. This research effort aspires to minimize the objective function, which is projected to reduce real power losses and voltage deviation, and it also aims to reduce the value of the real power performance index. The fitness function with appropriate weights is given as

$$Minf = W_1 \sum_{i=1}^{N} (1 - V_i)^2 + W_2 \sum_{j=1}^{nl} P_{Lj} + W_3 \sum_{\substack{allcongested \\ branches}} PI_{RP}, \tag{15}$$

where V_i is the actual voltage of the ith bus, P_{Lj} is the real power losses in the jth line, N is the total number of busses in the system, nl is the total number of lines in the system, and W_1, W_2, and W_3 are the respective weights of the objectives of voltage deviation, real power losses, and real power performance index.

This is subjected to the power equilibrium constraint:

$$\Sigma_{i=1}^{ng} P_g = \Sigma_{i=1}^{nl} P_d + P_{losses}, \tag{16}$$

where P_g is the power generated from generators in MW, P_d is the power demand in MW, P_{losses} is the power losses in the system, ng is the total number of generators available in the system, and nl is the total number of lines in the system.

The voltage level and angle of each bus is restricted between its minimum and maximum limits:

$$V_i^{min} \leq V_i \leq V_i^{\max}, \tag{17}$$

$$\delta_i^{min} \leq \delta_i \leq \delta_i^{\max}, \tag{18}$$

where V_i is the actual voltage of the ith bus; V_i^{min} and $V_i^{\max}$ are the minimum and maximum voltage limits of the ith bus, respectively; δ_i is the actual voltage angle of the ith bus; and δ_i^{min} and $\delta_i^{\max}$ are the minimum and maximum voltage angle limits of the ith bus, respectively.

The thermal limit of transmission line is given as

$$|S_{ij}| \leq \left| S_{ij}^{\max} \right|, \tag{19}$$

where S_{ij} is the actual line flow in the line, which is connected between buses i and j, and $S_{ij}^{\max}$ is the thermal rating of the same line.

3.1. Steps to find the optimal size of DG units by GA

The following steps are employed to find the accurate capacity of DG units to be connected in selected load bus locations.

Step 1: The data of the test system are read and initialize the iteration count (k) as 0.

Step 2: The base case load flow with MATPOWER environment and N-1 contingency analysis are performed.

Step 3: If there is no congestion, the results are printed. Otherwise, proceed to the next step.

Step 4: The PI_{RP} values of all contingencies are calculated as given in Eq. (1) and they are arranged in descending order. The most critical contingency is determined by using this procedure and this is known as contingency selection.

Step 5: The LFSI values of all load buses are calculated by using Eq. (10), due to the outage of congested lines of the most severe contingency.

Step 6: The calculated LFSI values are arranged in descending order and the buses that have the highest negative values are selected as optimal DG locations.

Step 7: The problem is mathematically formulated as given in Eq. (15) and subjected to the constraints as given in Eqs. (16)–(19).

Step 8: The optimization parameters are selected and the optimal sizes of DG units are determined using the GA.

Step 9: The optimal sizes of DG units are connected in already determined optimal locations.

Step 10: The algorithm is stopped and the best solution is printed when it reaches the maximum iteration count; otherwise, the iteration count is incremented and it is repeated from step 2.

A flow chart that illustrates the above steps of this proposed approach by GA is depicted in Figure 1. It is very essential to select the accurate parameters for the GA for getting successful optimization results. The various parameters that are used in this investigation are properly chosen in accordance with the above rule. The requisite codes are developed in MATLAB version 2012 and the simulations are performed on an Intel core I3 processor with 2 GB RAM.

4. Results and discussion

Simulations are executed in a modified IEEE 30-bus test system to validate the appropriateness of this projected technique. The single-line diagram of test system is shown in Figure 2, which consists of 24 load buses, 41 branches, and 6 generators. Bus 1 is assigned as the slack bus. The total real and reactive power requirements of the proposed system are 283.4 MW and 126.2 MVAR, respectively [17].

Initially, base case load flow is performed with the Newton–Raphson load flow technique to observe the violation of thermal limits in the transmission lines. If the said limit gets violated it means that congestion occurs in that corresponding transmission line. It is found from the results of base case load flow analysis that the thermal parameters of all transmission lines are within the limit. Hence, it is noticed that there is no congestion in any of the 41 transmission lines.

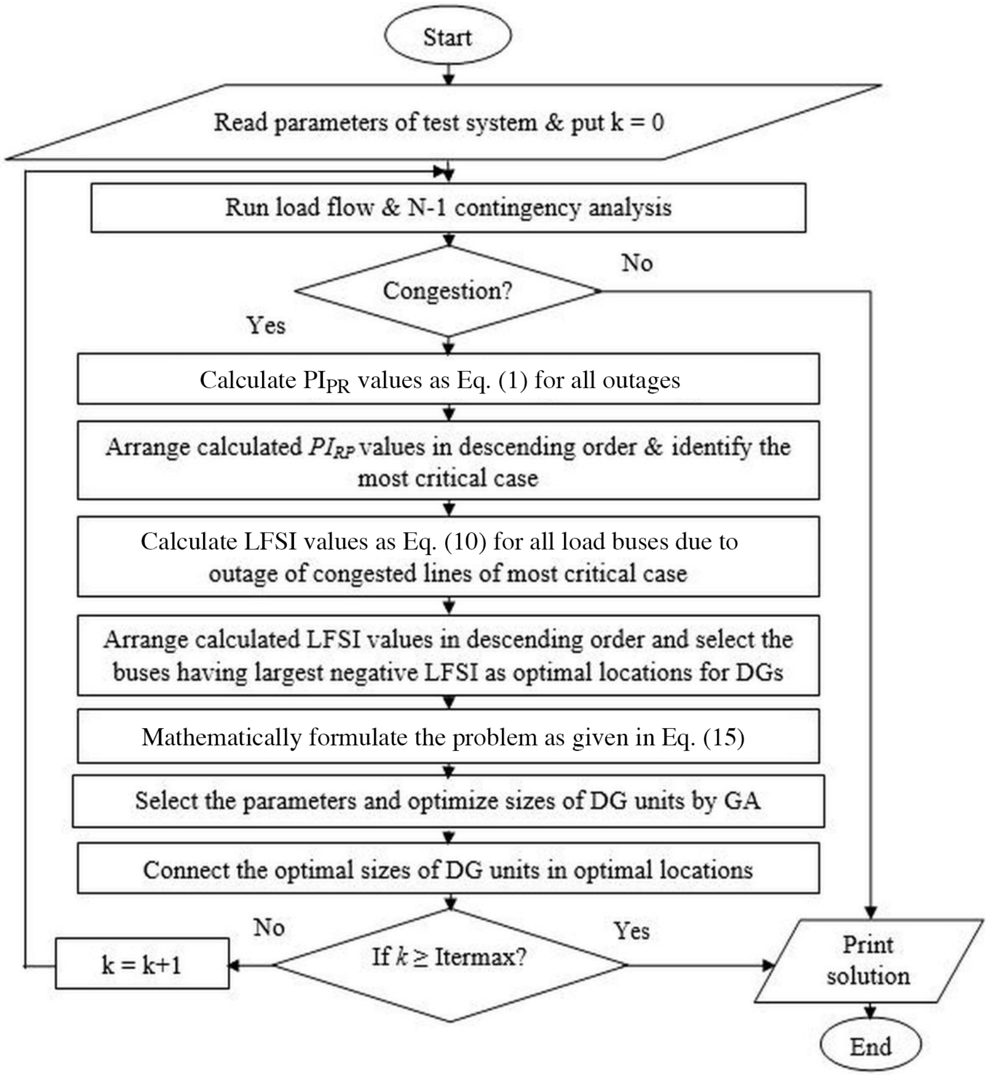

Figure 1. Flow chart for congestion relief by optimal DG size and location using GA.

Subsequently, the N-1 contingency measure is carried out to find the critical outage cases and the results are shown in Table 1. From this analysis, it is found that the outage of lines such as 1-2, 1-3, 3-4, 2-5, 4-6, and 10-20 and the outage of generators 2, 5, and 8 result in congestion in some of the corresponding transmission lines. All of these outage cases are considered for further investigation in this research.

The values of PI_{RP} are then calculated using Eq. (1) for the 9 identified as most serious cases so as to explore the dangerous contingency grading in the test system. The most serious outages with the given level of loading are ranked based on their respective PI_{RP} values in downward order and are specified in Table 2. It is evident from Table 2 that the outage of line 1-2 holds the top position and it is identified as the most dangerous contingency case.

Congested transmission lines are identified and listed as 1-3, 3-4, and 4-6 with an overloading of 148.103%, 139.008%, and 125.371%, respectively, for the most dangerous case, i.e. the outage of line 1–2. This research recommends a novel approach for alleviating this congestion by locating the DG units at appropriate sites of the load buses instead of performing the rescheduling process.

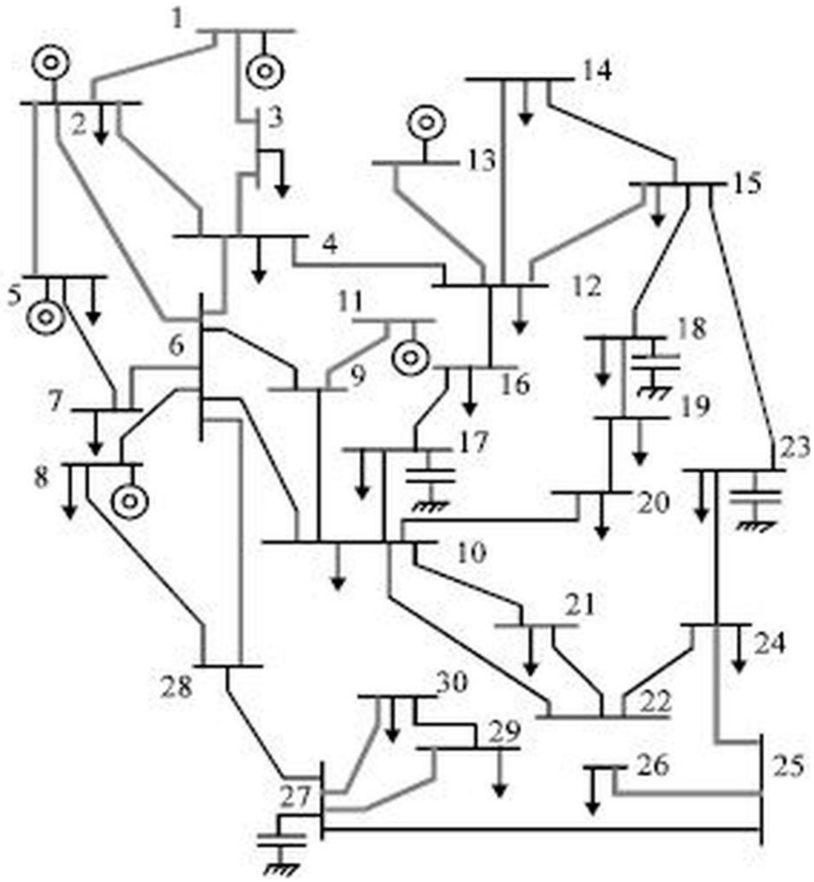

Figure 2. Single-line diagram of modified IEEE 30-bus system.

Table 1. The results of contingency measure before the placement of DG units.

Outage of line/generator	Congested lines	Line limit (MVA)	Line flow (MVA)	% of line loading	% of line congestion
1-2	1-3	130	192.53	148.10	48.10
	3-4	130	180.71	139.00	39.00
	4-6	90	112.83	125.37	25.37
1-3	1-2	130	182.38	139.52	39.52
	2-6	65	66.74	102.68	2.68
3-4	1-2	130	178.63	137.41	37.41
	2-6	65	65.81	101.25	1.25
2-5	2-6	65	76.90	118.32	18.32
	5-7	70	75.99	108.56	8.56
4-6	1-2	130	134.06	103.12	3.12
	2-6	65	71.73	110.35	10.35
10-20	15-18	16	16.31	101.97	1.97
2	1-2	130	162.01	124.63	24.63
5	1-2	130	136.74	105.18	5.18
8	1-2	130	135.31	104.08	4.08

Table 2. Contingency grading based upon PI_{RP}.

Sl. no.	Outage of line/generator	PI_{RP}
1	1-2	11.169
2	2-5	5.077
3	1-3	4.843
4	3-4	4.7
5	4-6	4.438
6	2	3.042
7	5	2.168
8	8	2.123
9	10-20	1.040

The DG units are normally connected within the distribution network, which is attached to load buses of the system. Hence, it is necessary to find the most sensitive load buses for connecting DG units. To find the suitable locations for DG units, the values of LFSI are calculated for all 24 load buses. This calculation of LFSI values is repeated for every congested line due to the most dangerous contingency, i.e. the outage of line 1-2. All 24 values of LFSI for every congested line are ranked in a downward manner. The top five values of LFSI and their respective load buses are listed in Table 3. Among the five suitable locations of every congested line, the load buses that have the highest negative values of LFSI are selected for the placement of DG units.

Table 3. Five potential sites for DG units derived from LFSI.

Sl. no.	Line 1-3		Line 3-4		Line 4-6	
	Bus no.	LFSI	Bus no.	LFSI	Bus no.	LFSI
1	22	–0.3698	22	–0.1817	23	–0.3965
2	23	–0.3120	23	–0.1486	22	–0.3689
3	9	–0.3052	7	–0.1185	29	–0.2428
4	7	–0.2746	15	–0.1035	19	–0.2393
5	3	–0.2720	21	–0.0918	21	–0.2392

It is evident from Table 3 that buses 22 and 23 have the highest negative values of LFSI. According to the methodology explained in Section 2.2, buses 22 and 23 are recognized as the most appropriate sites for the allocation of DG units pertaining to congested lines 1-3, 3-4, and 4-6.

After finding the most favorable places for connecting DG units, efforts are focused on finding of the best size of DG units in these prescribed sites. For doing so, GA-based optimization is adopted as discussed in Section 3.1. The best possible capacities of DG units are computed as 36.5990 MW and 19.0907 MW placed at buses 22 and 23, respectively. The plot of objective function convergence characteristics against iteration number is shown in Figure 3.

The percentage loadings in the most critical lines become 29.77%, 27.62%, and 38.04% for the system base case with the placement of DG units. The percentage loadings during the most dangerous contingency without DG units become 148.10%, 139.01%, and 125.37% for congested lines 1-3, 3-4, and 4-6, respectively. The percentage loadings in congested lines with a similar contingency get reduced to 96.14%, 90.52%, and 84.10% after the placement of DG units in the best identified sites. It is also interesting to note that the overloaded lines 1-3, 3-4, and 4-6 are relieved at 3.9806%, 9.5926%, and 15.9254%, respectively, for a similar dangerous contingency case.

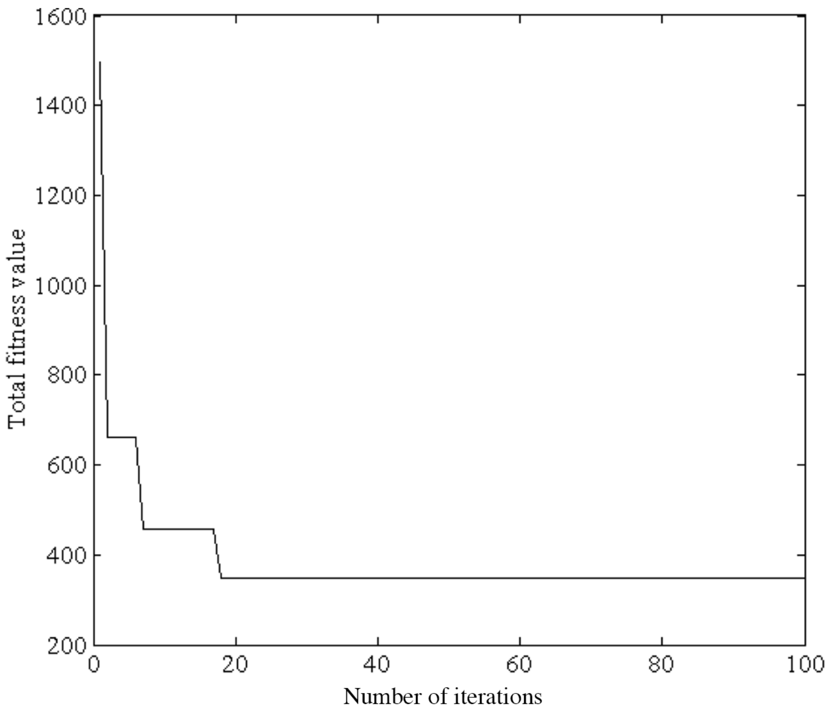

Figure 3. Convergence characteristics of objective function.

Reduction of real power losses and real power flow performance index are considered as the objectives in this study. Hence, the total system losses and the values of performance index of congested lines before and after placing the DG units are observed and noted in Table 4. From Table 4, it is evident that there is an appreciable amount of reduction in real reactive power losses and real power performance index values of congested lines.

Table 4. The comparison of parameters before and after placing the DG units.

Cases	PLoss (MW)	QLoss (MVAR)	PI value for outage of line 2-5	PI value for outage of line 10-20	PI value for outage of line 10-20
Before DG units placement	9.482	–9.897	5.077	1.040	No congestion
After DG units placement	5.875	–25.903	2.389	1.037	1.001
Reduction	3.607	16.006	2.688	0.003	NA*
% reduction	38.04	161.73	52.94	0.288	NA*
*NA: not applicable.					

The real power losses and real power flow performance index are the basic components of the fitness value of this proposed method. Thus, the convergence characteristics of real power loss and real power flow performance index after the placement of DG units are not separately shown in this study.

After placing the DG units in selected locations, the contingency assessment is performed again and the results are listed in Table 5. It is apparent that the congestion in most of the lines due to various contingencies completely gets alleviated, except for line 5-7 and line 15-18 due to outage of lines 2-5 and 10-20, respectively. However, in addition to the above 2 lines, line 22-21 newly gets congested due to the outage of line 10-22. After placing the multiple DG units in appropriate locations, the total number of congested lines gets reduced from 15 to 3 inclusive of the new congested line 22-21.

Table 5. The comparison of contingency measure results after the placement of DG units.

Outage of line/ generator	Congested lines	Line limit (MVA)	Line flow without DG units (MVA)	With DG units Line flow (MVA)	% of line loading	% of line congestion
1-2	1-3	130	192.53	125.98	96.91	Relieved
	3-4	130	180.71	119.32	91.78	Relieved
	4-6	90	112.83	75.74	84.15	Relieved
1-3	1-2	130	182.38	121.28	93.29	Relieved
	2-6	65	66.74	42.84	65.91	Relieved
3-4	1-2	130	178.63	118.64	91.26	Relieved
	2-6	65	65.81	41.94	64.53	Relieved
2-5	2-6	65	76.90	56.73	87.28	Relieved
	5-7	70	75.99	75.67	108.10	8.10
4-6	1-2	130	134.06	91.27	70.21	Relieved
	2-6	65	71.73	46.27	71.19	Relieved
10-20	15-18	16	16.31	16.29	101.81	1.81
10-22	22-21	32	30.24	32.02	100.07	0.07
2	1-2	130	162.01	123.37	94.90	Relieved
5	1-2	130	136.74	98.50	75.76	Relieved
8	1-2	130	135.31	96.89	74.53	Relieved

To confirm the robustness of this proposed approach, 20 independent runs are performed with 100 iterations. The results are computed with statistical investigation and they are given in Table 6.

Table 6. Statistical analysis with 20 independent runs.

Sl. no.	Statistical parameter	Fitness value
1	Mean	347.858935
2	Best	347.7779
3	Worst	347.9427
4	Standard deviation	0.051197628

The plot between fitness value and number of runs is shown in Figure 4. The maximum and minimum values of 20 independent runs can be easily noted from Figure 4.

Even though there are many proven algorithms presented for optimal DG siting and sizing, most of them are deterministic methods [2–10]. Power loss minimization or cost minimization is the only objective of the above-mentioned methods, without focusing on transmission congestion relief. However, this proposed approach aims to alleviate the transmission congestion along with power loss minimization. This is achieved by utilizing the LFSI and GA-based optimization for the optimal location and capacity of multiple DG units, respectively. The LFSI proves its supremacy in pointing out the optimal sites of multiple DG units for alleviating the transmission congestion effectively.

The DG units with anticipated output power such as biomass, fuel cell, and microturbines are only considered in this analysis. If DG units with variable power such as wind and solar photovoltaic power are selected, then the meteorological and demographic factors of such locations are to be considered during the calculation of the load flow analysis of the proposed approach. However, the methodology presented in this paper is effective, useful, and supportive for system designers in effective congestion relief by selecting the optimal sites of multiple DG units with exact capacity.

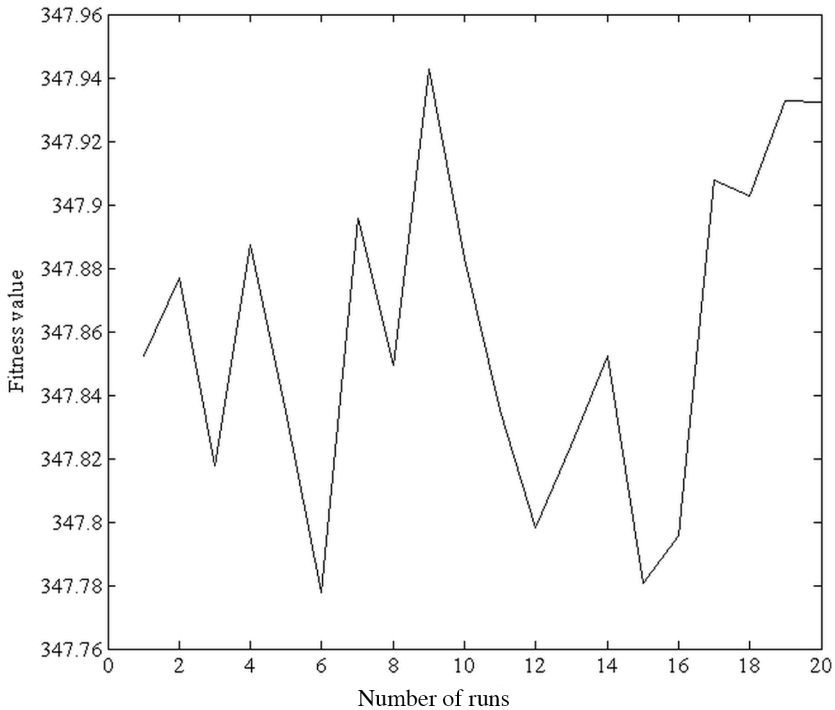

Figure 4. Plot between fitness value and number of runs.

5. Conclusion

In this research, congestion relief is performed with the optimal placement and size of DG units. It is obvious that inappropriate size and incorrect location of DG units induces higher power losses and serious voltage troubles. Therefore, this research employs the LFSI to determine the most favorable sites for DG units and the GA for choosing the best size of DG units. The objective of this investigation is the minimization of real power losses, voltage violation, and real power performance index. The pragmatism of this projected method is tested in the modified IEEE 30-bus test system.

The results of N-1 contingency analysis after placing the DG units prove the competence of this proposed approach, since the total number of congested lines gets reduced from 15 to 3 with the reduced level of percentage violation. Modern approaches like demand-side management and FACTS devices may be added additionally along with this proposed method to relieve congestion completely.

This method of congestion relief exhibits its ruggedness in reaching the optimal solutions, as it has considered the minimization of real power performance index as one of the objectives. Comparatively, this method of congestion relief is superior to all other methods because it employs renewable energy sources, which help in the reduction of environmental pollution.

In the present scenario of the electricity market, a power system without DG equipped with renewable energy sources is impracticable. Under this condition, this proposed approach certainly paves some newer paths both for energy producers and market operators to handle complex problems like transmission congestion, voltage instability, and increased level of system losses in an effective way.

Nomenclature

DG	Distributed generation
LFSI	Line flow sensitivity index
GA	Genetic algorithm
FACTS	Flexible AC transmission systems
PSO	Particle swarm optimization

RED	Relative electrical distance
TTC	Total transfer capability
TCSC	Thyristor controlled series compensator
PI_{RP}	Real power flow performance index
$w_l \& w_j$	Weighting factors of line l and bus j respectively as 2
P^i_{flowl}	Line flow in lth line for ith outage
$P_l^{\max}$	Rated capacity of lth line
N	The total number of buses in the system
2n	The order of real power performance index as 2
ΔV^i_j	The voltage at bus j with ith outage
ΔP_l	Change in real power injection at lth node
ΔQ_l	Change in reactive power injection at lth node
ΔS_{ij}	Change in line flow between node i and j
S_{ij}	Line flow between node i and j
P_l	Real power injection at lth node
Q_l	Reactive power injection at lth node
P_g	Power generated from generators in MW
P_d	Power demand in MW
ng	Total number of generators available in the system
nl	Total number of lines available in the system

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