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An Approach to Volt/Var Control in Distribution Networks with Distributed Generation

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Due to deregulation and restructuring in many countries, it is expected that the amount of small-scale generations connected to the distribution networks will increase. So, it is necessary that the impact of these kinds of generators on Volt/Var control should be investigated. This paper presents a new approach to Volt/Var control in distribution systems with Distributed Generation (DG). It has been shown that DG can improve the entire performance of a network system, by means of better control and decreasing losses. In this approach, the Genetic Algorithm (GA) has been used as the optimization method, where the amount of DG and its controlling parameters, the voltage regulators situation, the status of the load tap changers and, finally, the amount of switched capacitor, have been assumed as state variables. This method is tested on IEEE 34 bus radial distribution test feeders and a rural distribution network. The results are presented and it is shown that in the case of the selection of a correct location for DG, the system losses can be decreased by up to 70%.

INTRODUCTION

After deregulation and restructuring in many countries, it is expected that the amount of small-scale generations connected to the distribution networks will increase. A study by the Electric Power Research Institute (EPRI) indicates that by 2010, 25% of the new generation will be distributed and, also, a study by the Natural Gas Foundation concluded that this figure could be as high as 30% [1].

Volt/Var control is one of the important control schemes at a distribution substation, which conventionally involves the regulation of voltage and reactive power at a substation bus. The control is achieved by a Load Tap Changer (LTC), Voltage Regulators (VR) and Capacitors.

It is, therefore, necessary that the impact of DGs on Volt/Var control should be analyzed. Some Volt/Var control algorithms have been already developed by researchers [2-6].

This paper presents a new algorithm for Volt/Var control in distribution systems with Distributed Generations (DGs). The aim of this algorithm is to minimize electric power loss in distribution networks with control of DGs, capacitors, voltage regulators and a load tap changer for daily load variation. A genetic algorithm is used to minimize the objective function. This paper considers a model of local controllers. The control variables in this algorithm are the reactive power of distributed generators and substation capacitors and the tap of a load tap changer.

The method is tested on IEEE 34 bus radial distribution test feeders and a rural distribution network.

OBJECTIVE FUNCTION

From a mathematical standpoint, the Volt/Var control optimization problem is a minimization problem with inequality constraints. The objective function is a summation of losses in the distribution system for load variation, including transformer and line losses. The value of the objective function is determined from the power flow solution.

The objective function is given by the following equation:

$$F(x) = \min \mathrm{Ploss}^{\mathrm{dt}}. \tag{1}$$

Subject to:

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1. $V_{i\,\min} \le V_i \le V_{i\,\max}, \quad i = 1, 2, \cdots, N,$
2. $Pf_{\min} \le Pf \le Pf_{\max},$
3. $Q_{gi\,\min} \le Q_{gi} \le Q_{gi\,\max}, \quad i = 1, 2, \cdots, N_g,$
4. $T_{i\,\min} \le T_i \le T_{i\,\max}, \quad i = 1, 2, \cdots, N_t,$
5. $Q_{ci\,\min} \le Q_{ci} \le Q_{ci\,\max}, \quad i = 1, 2, \cdots, N_c,$
6. Load flow equations $g(P, Q, V, \delta) = 0,$

where:

V_i = bus voltage,
$V_{i\,\min}, V_{i\,\max}$ = minimum and maximum voltage for each bus,
Pf = power factor in substation,
$Pf_{\min}$ and $Pf_{\max}$ = minimum and maximum power factor in substation,
Ploss = sum of losses in line and transformers,
Q_{gi} = reactive power for each generator,
$Q_{gi\,\min}, Q_{gi\,\max}$ = minimum and maximum reactive power for each generator,
T_i = tap for LTC and VRs,
$T_{i\,\min}, T_{i\,\max}$ = minimum and maximum tap for each transformer and VRs,
Q_{ci} = reactive power for each capacitor,
$Q_{ci\,\min}, Q_{ci\,\max}$ = minimum and maximum reactive power for each capacitor,
dt = duration of time for load variation,
N_t = number of transformers,
N_c = number of capacitors,
N_g = number of generators.

UNBALANCED THREE PHASE POWER FLOW

In three-phase unbalanced power flow, the following components are modeled by their equivalent circuits, in terms of inductance, capacitance, resistance and injected current:

a) Distributed Generators: DGs are modeled as constant P and Variable Q;

b) Transformers: Transformers are modeled as equivalent circuits with fictitious current injections;

c) Capacitors: Capacitors are represented by their equivalent injected currents;

d) Demands or Loads: System loads are basically considered asymmetrical; because of single load and unequal three-phase loads.

In this paper, a network-topology, based on a three-phase distribution power flow algorithm, has been used. Two matrices are used to obtain the power flow solution. They are the Bus Injection to Branch Current (BIBC) and the Branch Current to Bus Voltage (BCBV) matrices [7].

VOLTAGE REGULATOR AND LTC MODEL

Voltage along primary distribution feeders is often controlled by voltage regulators and LTC. These regulators are autotransformers with individual taps on their windings. LTC and voltage regulators are modeled as follows.

Assume the transformer has been connected between buses M and N and has initial tap ratio (t) and physical admittance (Y) as shown in Figure 1a. This transformer is described by the π model with indirect representation of the transformer tap ratio (Figure 1b) by its series and shunt admittances.

When the transformer tap ratio changes from t to $t + \Delta t$, the transformer model should change, as shown in Figure 2a. Another way to simulate tap position changes is to modify the model (Figure lb) by adding fictitious injection currents, as shown in Figure 2b.

In order to make voltage and current in systems a and b (Figure 2) the same, fictitious injection currents are calculated as follows:

$$I_M = (1 - (t + \Delta t))^* \, Y^* V_N,$$

$$I_N = (1 - (t + \Delta t))^* \, Y^* V_M + \left((t + \Delta t)^2 - 1\right)^* Y^* V_N. \tag{2}$$

METHOD FOR LOCAL CONTROLLER MODELING

The aim of the local controller modeling is to determine LTC tap positions and the number of capacitor banks to be connected. A local controller changes tap positions or the number of capacitor banks in such a way that the desired setting becomes equal to the corresponding parameter within the range of the bandwidth. The parameter value is measured directly or calculated, based on the real-time measurements:

$$\Big|\mathrm{Setting}(V_{\mathrm{meas}}, I_{\mathrm{meas}}, \delta_{\mathrm{meas}}) - \mathrm{Param}(V_{\mathrm{meas}}, I_{\mathrm{meas}}, \delta_{\mathrm{meas}})\Big| \langle BD, \tag{3}$$

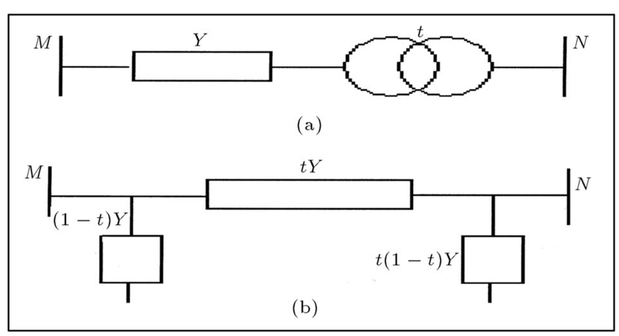

Figure 1. Transformer and voltage regulator model.

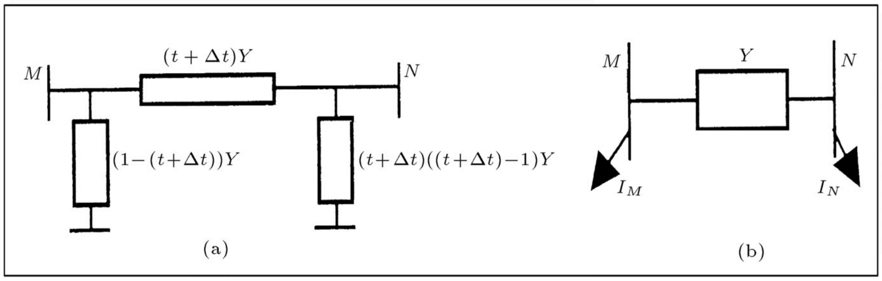

Figure 2. (a) Transformer model with a new ratio; (b) Equivalent circuit with fictitious current injections.

where voltage V_{meas}, current I_{meas} and phase angle δ_{meas} are measured values; BD is one half of a bandwidth; setting and Param are desired setting and calculated values for the parameter that one wants to control.

Different local controllers within the same distribution subsystem are usually coordinated through time delays. Time delay coordination means that the response time of different types of controllers to change power flow conditions is different.

In the method described below, it is assumed that time coordination between different controllers is done correctly. Controller modeling should start with the controllers having the smallest time delays and, then, to consider those with higher delays.

The method for the modeling of local controllers may be described as follows:

1. Solve the power flow equation with initial LTC tap positions and capacitor bank connections;
2. Among all available controllers, find the controllers with the smallest time delay and select them for a simulation. If no controllers are selected, EXIT;
3. For selected controllers, calculate Setting $(V_{\text{calc}}, I_{\text{calc}}, \delta_{\text{calc}})$ and Param $(V_{\text{calc}}, I_{\text{calc}}, \delta_{\text{calc}})$ terms of Inequality 3, where subscript "calc" refers to values calculated in the power flow;
4. Check Setting $(V_{\text{calc}}, I_{\text{calc}}, \delta_{\text{calc}})$ with maximum and minimum limits. If each of these limits is violated, set to be equal to the violated limit;
5. Check Inequality 3 for each selected controller. If the inequality is satisfied, the controller is not simulated;
6. Based on the values of Setting $(V_{\text{calc}}, I_{\text{calc}}, \delta_{\text{calc}})$ and Param $(V_{\text{calc}}, I_{\text{calc}}, \delta_{\text{calc}})$, bandwidth and the device step granularity, determine the direction and number of additional steps (positions or banks) needed;
7. If any controller from the selected group has the additional number of steps not equal to zero, solve the power flow equation with control actions simulated and return to step 3;
8. Put a tag "unavailable" on all controllers currently selected for modeling. Return to step 2.

DISTRIBUTED GENERATION MODEL

Depending on the contract and control status of a generator, it may be operated in one of the following modes:

1. In "parallel operation" with the feeder, i.e., the generator is located near and designed to supply a large load with fixed real and reactive power output. The net effect is reduced load at a particular location;
2. To output power at a specified power factor;
3. To output power at a specified terminal voltage.

The generation nodes in the first two cases can be well represented as PQ nodes. The generation nodes in the third case must be modeled as PV nodes. An approach to the modeling of the generator as PV nodes has been presented by Niknam and Ranjbar, based on the compensation method [7].

In this paper, generators are modeled as constant P and variable Q. Generally, DG, based on reactive power control, could be classified as follows:

1. Balanced three-phase reactive power control of DGs. In this case, reactive powers in each of three phases are controlled simultaneously;
2. Unbalanced three-phase reactive power control of DGs. In this case, each phase of DGs can be controlled independently.

GENETIC ALGORITHM

Genetic Algorithms are searching and optimization methods, based on a model of evolution adaptation in nature. They are very powerful search algorithms and are different from conventional search algorithms. GA does not need derivatives or other auxiliary knowledge.

GA works with a population of individuals and each individual stands for a solution. The quality of a solution is evaluated by its fitness, which is calculated by a fitness function [8].

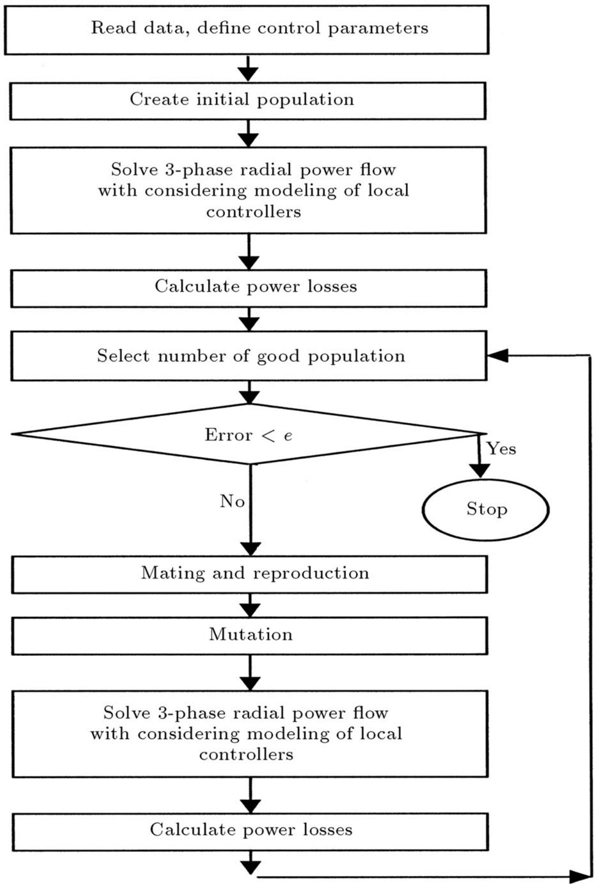

Figure 3. Flowchart of Vol/Var control.

In this paper, Integer strings, instead of binary coding, are used to represent values of variables and include the following processes:

- Representation and initialization,
- Fitness function,
- Reproduction operation,
- Crossover operation,
- Mutation operation.

SOLUTION AND FLOWCHART

Since Volt/Var control is an optimization problem, a genetic algorithm has been used to solve it. Figure 3 shows a flowchart of this algorithm.

At first, in this method, initial population is produced based on control variables, including the reactive power of DGs, the substation capacitor and the tap of the LTC. The value of taps and the capacitors reactive power is considered as discrete. Then, for each member of the initial population, considering the modeling of local controllers, an unbalanced three-phase power flow is solved. After that, electric power losses for each member are calculated and sorted and then, a number of good members that have minimum losses, are selected. New offspring, based on a selected population, are produced by the roulette wheel reproduction rule. A mutation operator is applied to each gene, according to mutation probability, independently. After mutation, losses are calculated for each member of the new population. This process is repeated, until convergence is met.

SIMULATION

The proposed algorithm is tested on two distribution networks. In the following section, results for two cases are presented.

Case 1: IEEE 34 Bus Radial Test Feeders

Figure 4 shows the IEEE 34 bus radial distribution test feeders, where the line and load specifications are presented in [9]. For this system, it is assumed that there are three DGs connected at 9, 23 and 27,

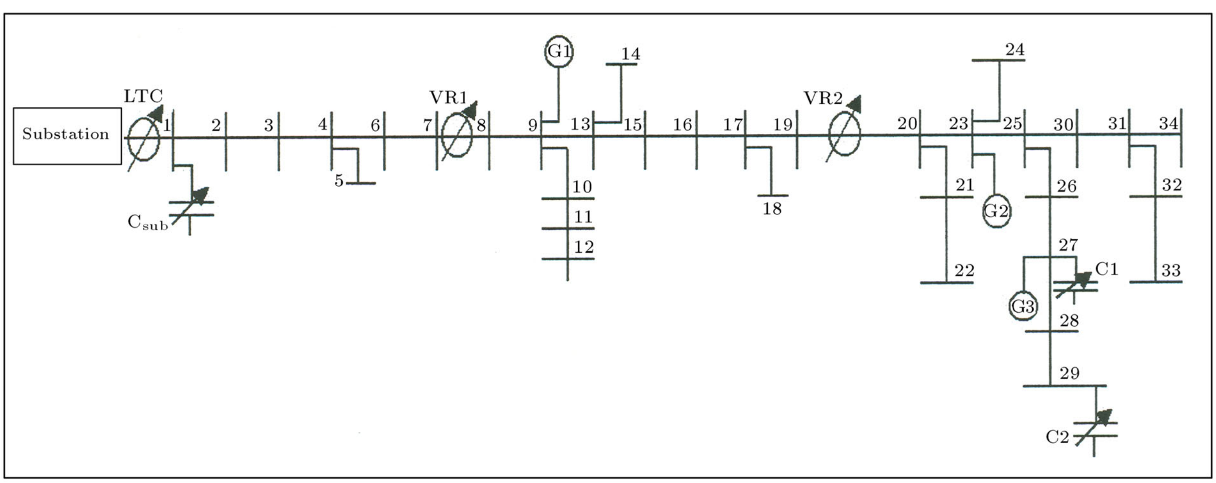

Figure 4. Single line diagram of IEEE 34 bus test feeders.

Table 1. DGs characteristics.

	G1	**G2**	**G3**
Active Power (kW)	90	120	150
Max Reactive Power (kVar)	72	96	120
Min Reactive Power (kVar)	-54	-72	-90

respectively and their specifications are presented in Table 1.

Figure 5 shows the load curve profile at all load points in the network.

Now, for using GA to determine the state variable of the system, i.e. tap of LTC, size of capacitors, Pf in substation, tap of voltage regulators and reactive power of generators, the following assumptions are made:

Initial population: 6000,
Number of good population: 300,
Number of load level: 3,
Limit of voltage magnitude: 0.95-1.05,
Limit of power factor in substation: 0.95-1,
Limit of tap position: 0.97-1.05,
Size of tap: 0.001,
$RT_{\text{VR1}} < RT_{\text{VR2}} < RT_{\text{Cap1}} < RT_{\text{Cap2}}$,
Limit of substation capacitor: 0-1000 kVar;
Limit of local capacitors: C1: 0-450 kVar;
C2: 0-300 kVar,
Mutation: $\mu = 0.04e^{-\text{Counter}}$,
$\varepsilon = 0.000001$,
$\text{Error} = \sum_{n=1}^{N_{\text{good}}} \left|\text{Cost}_n - \text{Cost}_{N_{\text{good}+1}}\right|$,

where counter and Cost_i are the number of iterations and the value of the objective function for the ith population, respectively. RT_i is the response time for each local controller.

In this approach, it is assumed that local controllers want to control their voltages.

In the following section, application of the method for various load conditions is presented.

Peak Load

In this case, it is assumed that in all nodes the load is at its maximum level.

Table 2 represents the results of simulation for this case. Also, the voltage profile has been presented in Table 3.

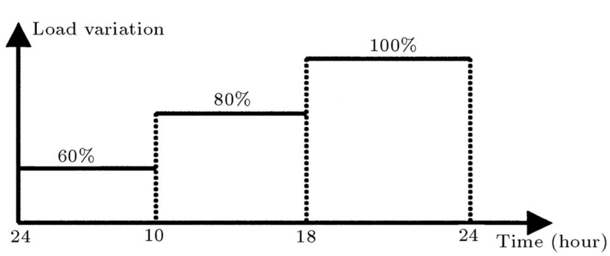

Figure 5. Load variation.

Table 2. Results of the simulation for peak load.

	With DG	**Without DG**
Tap of LTC	1.03	1.01
Size of Substation Capacitor (kVar)	669	792
***Pf* in Substation**	0.9995	0.9978
Power Losses (kW)	47.0784	85.2623
Tap of Voltage Regulator (1)	1.011	1.03
Tap of Voltage Regulator (2)	1.016	1.03
Size of Capacitor 1 (kVar)	0	30
Size of Capacitor 2 (kVar)	0	30
QG1 (kVar)	60.08	-
QG2 (kVar)	88.87	-
QG3 (kVar)	116.17	-
Execution Time(s)	20-60	15-40

Table 3. Voltage profile for peak load.

No. Bus	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**
1	1.0300	1.0300	1.0300	1.0100	1.0100	1.0100
2	1.0298	1.0299	1.0299	1.0098	1.0098	1.0098
3	1.0294	1.0296	1.0295	1.0093	1.0094	1.0094
4	1.0223	1.0237	1.0234	1.0003	1.0019	1.0015
5		1.0237			1.0019	
6	1.0140	1.0172	1.0162	0.9900	0.9934	0.9923
7	1.0074	1.0120	1.0105	0.9818	0.9867	0.9850
8	1.0021	1.0099	1.0073	0.9901	0.9985	0.9956
9	1.0020	1.0099	1.0073	0.9900	0.9984	0.9955
10	1.0019			0.9899		
11	0.9982			0.9861		
12	0.9973			0.9852		
13	1.0002	1.0079	1.0052	0.9879	0.9962	0.9931
14		1.0079			0.9961	
15	1.0001	1.0078	1.0050	0.9877	0.9960	0.9929
16	0.9965	1.0042	1.0009	0.9835	0.9918	0.9881
17	0.9965	1.0041	1.0008	0.9834	0.9917	0.9880
18		1.0041			0.9917	
19	0.9901	0.9978	0.9933	0.9759	0.9842	0.9794
20	0.9930	1.0007	0.9941	0.9893	0.9978	0.9906
21	0.9788	0.9867	0.9799	0.9751	0.9837	0.9764
22	0.9786	0.9864	0.9797	0.9748	0.9835	0.9762
23	0.9923	1.0000	0.9932	0.9885	0.9970	0.9896
24	0.9923			0.9885		
25	0.9913	0.9990	0.9921	0.9875	0.9960	0.9885
26	0.9913	0.9990	0.9921	0.9874	0.9960	0.9884
27	0.9912	0.9989	0.9919	0.9873	0.9958	0.9883
28	0.9911	0.9987	0.9919	0.9873	0.9957	0.9882
29	0.9911	0.9987	0.9919	0.9872	0.9957	0.9882
30	0.9912	0.9990	0.9920	0.9874	0.9959	0.9883
31	0.9912	0.9989	0.9919	0.9873	0.9959	0.9882
32	0.9911	0.9989	0.9919	0.9873	0.9959	0.9882
33	0.9911			0.9872		
34	0.9911	0.9989	0.9919	0.9873	0.9959	0.9882
	With DG			Without DG		

80% Peak Load

In the second case, it is assumed that the load at various nodes is 80% of its peak value.

Table 4 represents the result of simulation for this case. The voltage profile for this case has been presented in Table 5.

60% Peak Load

The final case is one in which it is assumed that the loads at various nodes are 60% of its peak value.

Table 6 represents the result of the simulation for 60% of the peak load. The voltage profile for this case has been presented in Table 7.

Case 2. A Realistic 23 Bus 20 kV Network

The method is applied to a rural network, as shown in Figure 6. This system is used to supply power demand in a village located in the north of Iran. Line and load characteristics are shown in Tables 8 and 9, respectively. A line impedance matrix is presented in

Table 4. Result of the simulation for 80% of peak load.

	With DG	**Without DG**
Tap of LTC		1.03
Size of Substation Capacitor (kVar)		654
***Pf* in Substation**	0.9936	0.9987
Power Losses (kW)	20.0528	54.8624
Tap of Voltage Regulator (1)	1	1.012
Tap of Voltage Regulator (2)	1	1.016
Size of Capacitor 1 (kVar)	30	0
Size of Capacitor 2 (kVar)	60	0
QG1 (kVar)	66	-
QG2 (kVar)	91	-
QG3 (kVar)	116	-
Execution Time(s)	20-60	15-40

Table 5. Voltage profile for 80% peak load.

No. Bus	**Va**	**Vb**	**Vc**	**Va**	**Vb**	**Vc**
1	1.0300	1.0300	1.0300	1.0300	1.0300	1.0300
2	1.0299	1.0300	1.0299	1.0298	1.0299	1.0299
3	1.0297	1.0298	1.0297	1.0294	1.0295	1.0295
4	1.0251	1.0262	1.0260	1.0222	1.0234	1.0231
5		1.0262			1.0233	
6	1.0199	1.0223	1.0216	1.0138	1.0164	1.0156
7	1.0157	1.0192	1.0181	1.0072	1.0109	1.0097
8	1.0053	1.0113	1.0094	1.0025	1.0088	1.0067
9	1.0053	1.0113	1.0094	1.0024	1.0087	1.0066
10	1.0052			1.0023		
11	1.0022			0.9993		
12	1.0015			0.9986		
13	1.0042	1.0101	1.0081	1.0006	1.0068	1.0046
14		1.0100			1.0068	
15	1.0041	1.0100	1.0080	1.0005	1.0067	1.0044
16	1.0019	1.0078	1.0053	0.9970	1.0032	1.0004
17	1.0018	1.0077	1.0052	0.9969	1.0031	1.0003
18		1.0077			1.0030	
19	0.9979	1.0038	1.0005	0.9906	0.9967	0.9932
20	0.9900	0.9957	0.9908	0.9933	0.9996	0.9942
21	0.9787	0.9845	0.9795	0.9820	0.9883	0.9829
22	0.9785	0.9843	0.9793	0.9818	0.9882	0.9827
23	0.9896	0.9953	0.9903	0.9926	0.9988	0.9934
24	0.9896			0.9926		
25	0.9890	0.9947	0.9895	0.9917	0.9980	0.9924
26	0.9889	0.9947	0.9895	0.9917	0.9979	0.9923
27	0.9889	0.9946	0.9894	0.9916	0.9978	0.9922
28	0.9889	0.9945	0.9894	0.9915	0.9977	0.9921
29	0.9889	0.9945	0.9894	0.9915	0.9977	0.9921
30	0.9889	0.9946	0.9894	0.9917	0.9979	0.9922
31	0.9888	0.9946	0.9894	0.9916	0.9979	0.9922
32	0.9888	0.9946	0.9894	0.9916	0.9979	0.9922
33	0.9888			0.9915		
34	0.9888	0.9946	0.9894	0.9916	0.9979	0.9922
	With DG			Without DG		

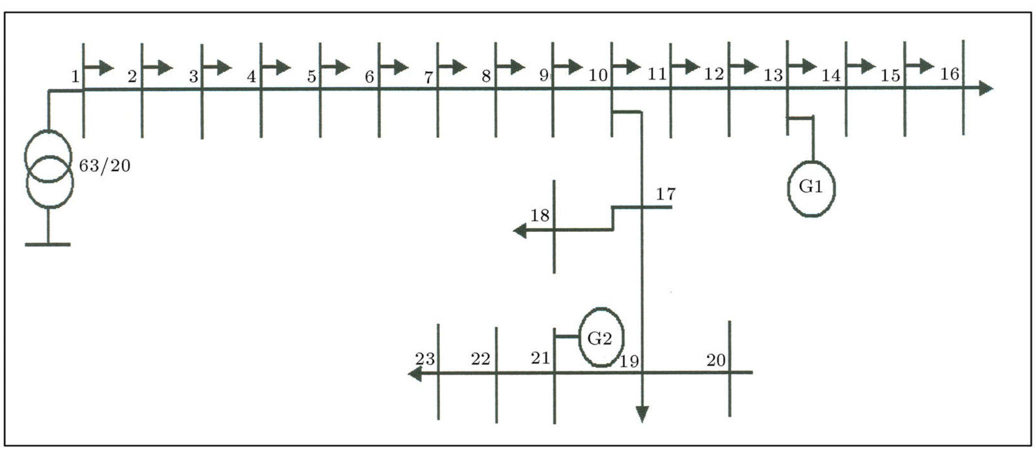

Figure 6. Single line diagram of rural network.

Table 6. Result of simulation for 60% of peak load.

	With DG	Without DG
Tap of LTC	1.02	1.03
Size of Substation Capacitor (kVar)	246	468
***Pf* in Substation**	0.9697	0.9993
Power Losses (kW)	9.3325	30.1406
Tap of Voltage Regulator (1)	1	1.001
Tap of Voltage Regulator (2)	1	1.01
Size of Capacitor 1 (kVar)	30	0
Size of Capacitor 2 (kVar)	30	0
QG1 (kVar)	63	-
QG2 (kVar)	60	-
QG3 (kVar)	43	-
Execution Time(s)	20-60	15-40

Table 7. Voltage profile for 60% peak load.

No. Bus	Va	Vb	Vc	Va	Vb	Vc
1	1.0200	1.0200	1.0200	1.0300	1.0300	1.0300
2	1.0199	1.0199	1.0199	1.0299	1.0299	1.0299
3	1.0197	1.0198	1.0198	1.0296	1.0296	1.0296
4	1.0164	1.0173	1.0171	1.0243	1.0251	1.0249
5		1.0172			1.0251	
6	1.0126	1.0144	1.0139	1.0181	1.0200	1.0194
7	1.0096	1.0122	1.0114	1.0133	1.0159	1.0151
8	1.0023	1.0067	1.0054	1.0020	1.0066	1.0051
9	1.0022	1.0067	1.0053	1.0020	1.0065	1.0051
10	1.0021			1.0019		
11	0.9999			0.9997		
12	0.9994			0.9991		
13	1.0014	1.0058	1.0043	1.0007	1.0051	1.0036
14		1.0057			1.0051	
15	1.0013	1.0057	1.0043	1.0005	1.0050	1.0035
16	0.9997	1.0040	1.0023	0.9979	1.0024	1.0005
17	0.9997	1.0040	1.0022	0.9979	1.0023	1.0004
18		1.0040			1.0023	
19	0.9968	1.0011	0.9987	0.9932	0.9976	0.9951
20	0.9909	0.9952	0.9916	0.9934	0.9979	0.9940
21	0.9825	0.9868	0.9831	0.9850	0.9895	0.9856
22	0.9823	0.9866	0.9830	0.9848	0.9893	0.9855
23	0.9906	0.9949	0.9912	0.9929	0.9973	0.9934
24	0.9906			0.9929		
25	0.9902	0.9944	0.9906	0.9922	0.9966	0.9927
26	0.9902	0.9944	0.9906	0.9922	0.9966	0.9926
27	0.9901	0.9943	0.9905	0.9921	0.9965	0.9925
28	0.9901	0.9943	0.9905	0.9921	0.9964	0.9925
29	0.9901	0.9943	0.9905	0.9921	0.9964	0.9925
30	0.9901	0.9943	0.9905	0.9922	0.9966	0.9926
31	0.9901	0.9943	0.9905	0.9921	0.9966	0.9925
32	0.9900	0.9943	0.9905	0.9921	0.9966	0.9925
33	0.9900			0.9921		
34	0.9900	0.9943	0.9905	0.9921	0.9966	0.9925
	With DG			Without DG		

the following equation.

$$Z_{\text{Line}}(\Omega/m) =$$

$$(1e-4)\begin{bmatrix} 7+j7 & .2+j.15 & .2+j.15 \\ .2+j.15 & 7+j7 & .2+j.15 \\ .2+j.15 & .2+j.15 & 7+j7 \end{bmatrix}. \tag{4}$$

As there is no DG in this network, currently, two typical DGs have been considered in buses 13 and 21 and their specifications have been presented in Table 10.

Simulation conditions are similar to Case 1 without considering VRs and capacitors. Also, the substation capacitor is 4000 kVar. In the following section, the application of the method for various load conditions is presented.

Peak Load

The result of simulation for peak load is represented in Table 11.

80% Peak Load

Table 12 shows the result of simulation for 80% peak load.

60% Peak Load

The final case is one in which it is assumed that the loads at various nodes are 60% of its peak value. The result of simulation for 60% peak load is represented in Table 13.

Table 8. Line characteristics.

No	From	To	Length (m)
1	1	2	40
2	2	3	280
3	3	4	140
4	4	5	120
5	5	6	330
6	6	7	725
7	7	8	210
8	8	9	210
9	9	10	55
10	10	11	60
11	11	12	1000
12	12	13	1020
13	13	14	870
14	14	15	865
15	15	16	865
16	10	17	1400
17	17	18	1700
18	17	19	70
19	19	20	70
20	18	21	1060
21	21	22	1500
22	22	23	520

Table 9. Load characteristics.

No	Pa (kW)	Qa (kVar)	Pb (kW)	Qb (kVar)	Pc (kW)	Qc (kVar)
1	0.00	0.00	0.00	0.00	0.00	0.00
2	105.00	78.75	114.45	85.84	95.55	71.66
3	83.33	62.50	90.83	68.13	75.83	56.88
4	83.33	62.50	90.83	68.13	75.83	56.88
5	83.33	62.50	90.83	68.13	75.83	56.88
6	83.33	62.50	90.83	68.13	75.83	56.88
7	83.33	62.50	90.83	68.13	75.83	56.88
8	83.33	62.50	90.83	68.13	75.83	56.88
9	83.33	62.50	90.83	68.13	75.83	56.88
10	83.33	62.50	90.83	68.13	75.83	56.88
11	105.00	78.75	114.45	85.84	95.55	71.66
12	105.00	78.75	114.45	85.84	95.55	71.66
13	83.33	62.50	90.83	68.13	75.83	56.88
14	83.33	62.50	90.83	68.13	75.83	56.88
15	21.00	15.75	22.89	17.17	19.11	14.33
16	333.33	250.00	363.33	272.50	303.33	227.50
17	133.33	100.00	145.33	109.00	121.33	91.00
18	83.33	62.50	90.83	68.13	75.83	56.88
19	105.00	78.75	114.45	85.84	95.55	71.66
20	105.00	78.75	114.45	85.84	95.55	71.66
21	50.00	37.50	54.50	40.88	45.50	34.13
22	0.00	0.00	0.00	0.00	0.00	0.00
23	105.00	78.75	114.45	85.84	95.55	71.66

Table 10. DGs characteristics.

	G1	G2
Active Power (kW)	800	700
Max Reactive Power (kVar)	640	560
Min Reactive Power (kVar)	-480	-420

Table 11. Result of simulation for peak load.

	With DG	Without DG
Tap of LTC	1.03	1.03
Size of Substation Capacitor (kVar)	2000	3500
Pf **in Substation**	0.995	0.9956
Power Losses (kW)	60.83	119.82
Max Voltage (kV)	20.6	20.6
Min Voltage (kV)	20.37	20.306
QG1 (kVar)	640	-
QG2 (kVar)	560	-
Execution Time(s)	12-40	12-30

Table 12. Result of simulation for 80% peak load.

	With DG	Without DG
Tap of LTC	1.03	1.03
Size of Substation Capacitor (kVar)	1760	3010
Pf **in Substation**	0.965	0.994
Power Losses (kW)	32.17	76.33
Max Voltage (kV)	20.6	20.6
Min Voltage (kV)	20.437	20.365
QG1 (kVar)	640	-
QG2 (kVar)	560	-
Execution Time(s)	12-40	12-30

Table 13. Result of simulation for 60% peak load.

	With DG	Without DG
Tap of LTC	1.03	1.03
Size of Substation Capacitor (kVar)	1010	2120
Pf **in Substation**	0.978	0.997
Power Losses (kW)	13.2	42.74
Max Voltage (kV)	20.6	20.6
Min Voltage (kV)	20.496	20.4242
QG1 (kVar)	640	-
QG2 (kVar)	560	-
Execution Time(s)	12-40	12-30

DISCUSSION

Comparison between results achieved by using GA in the above mentioned problem and those found by other investigations [3] shows the high accuracy and applicability of using the GA optimization algorithm in Volt/Var control in a distribution network incorporating DGs and control devices.

In Tables 2, 4, 6 and 11 to 13, comparison of system losses between pre and post installation of DGs is shown. After installation of DGs, since they reduce the line current flow, the system losses at each load level is reduced. For example, for 60% peak load (IEEE test feeder), DG caused power loss in the distribution system became 9.322 kW, which is comparable with 30.1406 kW in the case of no DGs. Distributed generation location affects active and reactive power flow, so if they are placed at suitable locations, power losses can be greatly decreased.

It must be mentioned that since all required constraints have been assumed in both cases (existence and nonexistence of DG) and the optimization problems have been solved, the voltage profile and substation power factors are the same for all cases and system losses only decreased when DGs existed, which also gives the possibility of Volt/Var control through the network.

These tables also show the execution time for the proposed algorithm, which is sufficiently short and gives a general idea that the method can be implemented without any restriction in realistic networks. In the worst case, it is less than 1 minute, which is much less than the required response time of a real network for Var control.

CONCLUSION

Since the number of DGs will be increasing and, also, the DGs affect voltage and reactive power control, it is necessary to study the impact of DGs on Volt/Var control. This paper presented an efficient algorithm for Vol/Var control in distribution with DGs. In the three-phase unbalanced power flow calculation, while modeling the local controllers of devices, the distribution system components are modeled by their equivalent circuits in terms of inductance, capacitance, resistance and injected current. Genetic algorithm is used to obtain the solution of the optimization problem. By using this algorithm, the performance of radial test feeders, with or without DGs, was analyzed and it has been shown that while accomplishing all the technical constraints in the network, i.e. voltage profile and substation load factor constraints, system loss decreased enormously in the cases where DGs existed. It is, therefore, revealed that by proper placement of DGs and by using appropriate controllers for them, it is possible to have a much better control of Volt/Var in the network while decreasing system losses.

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