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The Optimal Sizing and Placement of Renewable Distributed Generation in Distribution System

Madhuri.n.s.
PG Student [EPS], Dept. of EEE,
SITS, Kadapa,
Andhra Pradesh, India.
205madhuri@gmail.com

Abstract: The global requirement for sustainable energy provision will become major problem for the future because the environmental effects of fossil fuels become apparent. This trend has a makeable encouragement for private participation in capacity expansion in a market-oriented industry organization. In addition, installation of small generators located close to the load centres, may give more flexibility to the power market. Installation of Distributed Generation (DG) at non-optimal places can result in an increase in system losses, reconfiguration of protection scheme, voltage problems, in addition to direct benefits and cost, external cost should be evaluated. Environmentally friendly renewable energy technologies and cleaner fossil fuel technologies are among the available options to be installed close to the load centres. There are numerous benefits that can be achieved for the local distribution company (LDC) from the installation of DG units, among which three are considered in this work. The benefits are to relieve the congestions in network feeders, reduction of energy losses and reliability of the power supply. In this paper, a method to evaluate the worth of installing renewable distributed generation in distribution networks is proposed. Moreover, the work optimally allocates these DG units in the distribution network to maximize the worth of the connection to the local distribution company, as well as the customers connected to the system. The proposed methodology helps the LDC to better assess the benefits of the renewable DG units, proposed connections and to identify the optimal buses on which to connect these DG units.

Keywords: Distribution system, Distributed generation, Local Distribution Company, System reliability.

I. INTRODUCTION

As the yearly electric energy demand grows, there is a significant increase in the penetration of renewable distributed generation (DG) to fulfil this increase in demand. For sustainable energy supply the renewable energy resources are the best option because they are in-exhaustible and non-polluting. The local distribution company has no. of benefits with installation of renewable DG units, among them three main benefits are considered in this project work. They are: (i) relieving of congestions, (ii) reduced power loss & (iii) improved reliability.The Integration of a DG into an existing distribution system has significant impact on the system where as the improper allocation of DG units may lead to adverse effects. The planning problem has to face more technical & economical problems because of variable & uncertain nature of renewable energy sources. When optimizing the allocation problem with only one objective considered may lead to negative impact on system operation costs. To account all the benefits of installation of renewable DG units in distribution system, the multi-objective allocation should be done. So, from the above it is clear that DG allocation must be done very carefully according to the system constraints.

This papermainly concentrates about the economic benefits of optimal allocation of renewable DG and to maximize the delay of system upgrade investments, reduction of the energy losses cost & interruption cost, a multi objective mixed integer programming based methodology is implemented by considering various constraints like (i) uncertainty and variability associated with DG output; (ii) Variable hourly cost of energy; (iii) load variability and customer sector type; (iv) Protection and metering equipment upgrades; and (v) Nonlinear time dependent cost damage function.

II. PROBLEM DESCRIPTION

In this section, the system costs considered in the proposed long-term planning problem are described.

2.1 GENERATION AND LOAD MODELING

In this section the generation and load modeling are described, where the following assumptions are made.

- Hourly average load and wind speed data are considered in this work and the variations within the hour are neglected.
- Wind DG output power and load are modeled as a multistate variables, where the number of states represents a trade-off between accuracy and complexity of the planning problem.

2.1.1 WIND GENERATION MODELING

MCS is utilized for evaluating the cost of energy losses and cost of interruption, due to the variable hourly cost of energy and the non-linear cost damage function. On the other hand, a probabilistic wind speed model is used for evaluating the costs of upgrade. Thus, two models are described for the wind DG output power, probabilistic model and MCS model as follows:

1. Divide the entire year into clusters (seasons or months).
2. Generate a typical 24 hours day for each cluster in order to represent the random behavior of the wind speed.
3. Model the renewable resource behavior during each hour by a proper probability density function (PDF), then generate the probabilistic wind speed model utilizing the actual recorded historical wind speed data. A Weibull PDF is the most commonly used PDF to describe the wind variability. Its formula, given in depends on two parameters to fit the distribution function to the measured values of wind speeds. The parameters are calculated using the mean wind speed and the standard deviation.
4. Use the inverse of the cumulative distribution function of 'm' each hour, in MCS to generate virtual scenarios of the hourly wind speed, where a proper stopping criterion is required according to the type of analysis.
5. Utilize the failure rate of the wind based DG to generate an artificial two state availability model.
6. Convolve the models obtained in steps 4 and 5 to generate the final MCS model
7. Divide the entire speed range into a proper number of states according to the accuracy and speed of the simulation.
8. Calculate the output power of the wind based DG unit corresponding to the wind speed states in the wind DG models.

2.1.2 DISPATCHABLE DG UNIT MODELING

Dispatchable DG units can be divided into two groups: synchronous machine based (as diesel and natural gas based DG) and inverter based (as fuel cell and micro turbine based DG). In this work, natural gas DG units are considered. The output of these DG units is assumed to be fixed in normal mode of operation. However, during islanding mode the output of these DG units is assumed to be varied to manage the active and reactive power balance. A two-state-model is used to model the operation of each DG. This model is used in MCS to produce an artificial annual operating scenario for each dispatchable DG unit.

2.1.3 LOAD MODELING

The load in the distribution network under study is assumed to follow the IEEE reliability test system load pattern. The load is modeled by a definite number of states depending on desired accuracy, time scale and speed of simulation. Uncertainty of certain percentages could be used to generate different annual scenarios.

2.2 PROBLEM FORMULATION

In this section the proposed DG planning problem formulation is presented, which is classified as mixed integer nonlinear programming. The following assumptions are made:

- Most of the utilities force the DG units to operate in constant power factor mode. Thus, the DG units are assumed to operate at unity power factor.
- DG units' capacities are discretized at a definite step, which is assumed to be 100 kW in the presented work.

For combining the effect of DG units' installation on system upgrade, energy losses and reliability, the typical costs in Canadian dollars are used for each individual objective. In the next section GA is utilized to find the optimal sizes and locations of DG units to minimize the objective function. The proposed planning problem is described by the following.

Objective function:
Minimize:

$$\mathrm{Cost} = \mathrm{Cost(s)\ of\ obectives} + 10^8 \times \sum_{c}^{nc} \mathrm{X_c} - \mathrm{incentives} \qquad (1)$$

Where, Xc is a binary variable corresponding to constraint 'C' *nc* is the total number of constraints.

Subject to:

Power flow constraints:

$$P_{G_{i_{s_y}}} - P_{L_{i_{s_y}}} = \sum_{k=1}^{n} V_{i_{s_y}} V_{k_{s_y}} Y_{ik} \times cos\left(\theta_{ik} + \delta_{k_{s_y}} - \delta_{i_{s_y}}\right) \forall_{i,s,y}. \quad (2)$$

$$Q_{G_{i_{s_y}}} - Q_{L_{i_{s_y}}} = \sum_{k=1}^{n} V_{i_{s_y}} V_{k_{s_y}} Y_{ik} \times sin\left(\theta_{ik} + \delta_{k_{s_y}} - \delta_{i_{s_y}}\right) \forall_{i,s,y}. \quad (3)$$

Where, i and k are the bus number;
n is the total number of buses in the system under study;
s is the state number;
y is the year under study;
P_L and Q_L are the active and reactive power demands;
P_G and Q_G are the active and reactive generated powers.

Voltage limits constraints:

$$V_{min} \le V_{i_{s_y}} \le V_{max} \forall_{i,s,y}. \quad (4)$$

Maximum penetration:

Maximum penetration is taken so as to limit maximum reverse power flow at 60% of substation rating during minimum load condition:

$$\sum_{i=1}^{n} P_{DGD_i} + P_{DGW_i} \le 0.6 \times P_{main} + 0.3 \times \sum_{i=1}^{n} P_{L_i} \quad (5)$$

Where, P_{DGD}, P_{DGW}, and P_{main} are the generated power from dispatchable DG units, wind DG units and main substation, respectively.

Discrete size of DGunits:

$$P_{DGD_i} = g_i \times a_i \times 0.1\, MW \quad \forall_i \in DGB \quad (6)$$
$$P_{DGW_i} = w_i \times a_i \times 0.1\, MW \quad \forall_i \in DGB \quad (7)$$

Where, a_i and b_i are integer variables; g_i and w_i are binary variables indicating the decision of installing dispatchable DG unit and wind based DG unit at bus i, respectively.

Candidate buses:

$$g_i = 0, \quad w_i = 0 \quad \forall_i \in AllB - DGB \quad (8)$$

Where, AllB and DGB are sets of all buses and candidate buses, respectively

DG units limit:

$$\sum_{i=1}^{n} \mathrm{g_i} \le \mathrm{M_D}, \quad \sum_{i=1}^{\mathrm{n}} \mathrm{w_i} \le \mathrm{M_W} \quad (9)$$

Where, M_D and M_W are the maximum number of DG units installed in the system for dispatchable and wind based DG, respectively.

The meta-heuristic optimization techniques family proved its effectiveness in solving many complicated practical problems, such as DG planning, unit commitment, and economical dispatch. In the planning problem presented in this paper the GA is utilized, which is a population based searching algorithm. The population consists of chromosomes, and each chromosome consists of a number of genes.

For radial distribution systems the number of genes is selected to be a multiple of the number of candidate buses according to the types of DG units to be installed. For example, in case of considering two types of DG units in the allocation problem, like natural gas and wind based DG, each chromosome in the population consists of a vector of length equals to four times the number of the candidate busses, as shown in Fig. 1. For each candidate bus, there are four genes, which are shaded in Fig. 1. Two genes carry binary values, which indicate the decision of installing DG units for the two DG types at the corresponding bus. The other two genes carry integer values, which indicate the capacity of the corresponding DG units as a multiple of a definite step for each DG type.

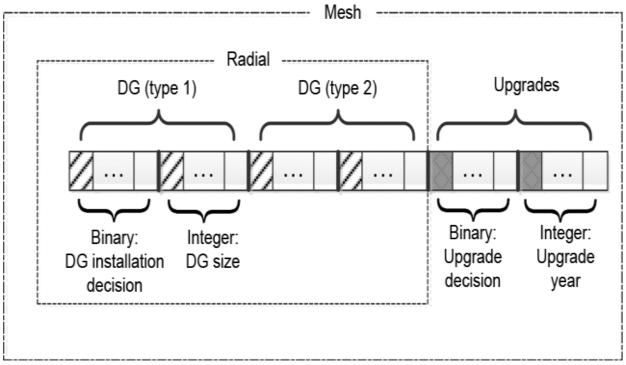

Fig.1.Structure of a typical chromosome in the proposed planning problem.

On the other hand, for mesh distribution networks, where there is more than one decision for lines' upgrades, the chromosome should include two extra genes for each line in the system, as shown in Fig. 1. The first gene carries a binary value that represents the decision of upgrading the corresponding line. The second gene carries an integer value that represents the year of upgrade.

In each iteration, the fitness of each individual in the population is evaluated. This fitness is the total cost of the considered objective(s) in the objective function described in (1). These costs are described in the following subsections.

A. System Upgrades

This subsection describes the methodology proposed for evaluating the cost of system upgrades. A risk factor (RF) is proposed which represents the expected duration of ever loading per year. This factor is used in evaluating the cost of lines' upgrades.

1) Lines' upgrades

For radial systems, considering the no DG case, the reinforcement costs can be evaluated at the extreme condition of power flow in the lines, which is simply one condition at peak load, as the power flow is always from the substation to the load points. However, in the case of DG units' presence in the system, the load flow analysis is performed for each state for this study. The procedure for evaluating the cost of system upgrades is described as follows:

a. For each state, go through steps b to d.
b. For each year, go through steps c to d.
c. Update loads with annual rise, and run load flow analysis for state and year.
d. For each line, record the year in which upgrade is required and calculate the corresponding net present value (NPV) of the cost of upgrade of each line for each state.
e. For each line, arrange the combined generation and load states in descending order according to the calculated NPV.
f. For each line, if the probability of the state corresponding to the maximum cost of upgrade is above the RF, proceed to step g; if not, proceed to the next state. If the sum of the probabilities of this state and the previous state(s) is higher than the RF go to step g; if not, proceed to next state and repeat the previous statement.
g. Record this upgrade cost and repeat step f for the next line.
h. The NPV of the required reinforcement investments during the period under study can be evaluated using the following formula [6]:

$$NPV_{upgrade} = \sum_{K=1}^{M} \mathrm{NPV_K} = \sum_{K=1}^{M} \frac{CK}{(1+d)^{iK}} \quad (10)$$

Where, NPV_k is the NPV of the reinforcement k;
C_k is the cost of the reinforcement k;
d is the discount rate;
M is the total number of required reinforcements;
i_k is the year when the reinforcement k is required.

For evaluating the cost of lines' upgrade in case of wind based DG units, if the RF is taken to be zero, the cost is greater than or equal to the cost of lines' upgrade without DG. For example, assume the combined load and generation states are 224 states. These states have two extremes, defined as rated DG output power with minimum load and zero DG output power with peak load. Each state contributes to line X upgrade. Assume that the state which contributes the most has a probability of occurrence of 0.05%. This corresponds to almost 4 hours per year. For zero RF, all the states are considered including the second extreme mentioned above, which is the case Without DG. Thus, for zero RF, the cost of each line upgrade is greater than or equal to the case without DG. For an RF of 6 hours per year, the most contributing state will be neglected because its probability of occurrences less than the RF and other states will be considered. This may result in reduced cost of the line's upgrade than the base case.

2) Metering equipment upgrade

At the substation terminals where the metering devices are installed, the direction of power flow is checked under the state of minimum load and rated DG output. Accordingly, the cost of upgrading the metering devices is evaluated.

3) Protection switch gear upgrade

To prevent false tripping and for effective fault clearing, A short circuit analysis of the system has to be carried out in the presence of installed DG units. Accordingly, the cost of upgrading the protective equipment is evaluated.

B. Cost of Energy Loss

The power loss for each state of the combined generation and load states is evaluated for 20 years with load growth. Then, the cost of the annual energy losses is evaluated for each year according to the following methodology.

The power loss for each year is represented as a vector of length in which each element represents the power loss corresponding to state's':

$P_{loss\ y} = [\ P_{loss1}\ P_{loss2}\ \ldots\ldots P_{lossNs}\ ]$ (11)

A binary variable is defined as

$S_z = [\,]_{8760*Ns}$ $\square_z = 1,2,\ldots.N_y$ (12)

Where, N_S is the total number of states of the combined load and generation model;
N_Y is the total number of scenarios in the probabilistic chronological model.

For the binary variable, each row consists $(N_s$-1) of zeros and one element of value 1; this element corresponds to the actual load state. This variable is generated only once for certain wind or solar regimes, and it allows for the hourly evaluation of the cost of energy losses.

For example, assume that the load states are given by {0.5, 1} and the generation states are given by {0, 1}. Thus, there are 4 combined load and generation states which are given by: States = {(0.5, 0), (0.5, 1), (1, 0), (1, 1)}.

Assume that the period under study is 5 hours. The hourly load curve and the hourly DG output are given by: P_L = [0.5,0.5,1,0.5,1], P_{DG} =[1,0,1,0,0];this means that in the first time segment the second state (0.5,1) occurs, then the first state (0.5,0) occurs and so on.

The state number represents the locations of the ones in the rows of the binary variable which is given by

$$S = \begin{bmatrix} 0 & 1 & 0 & 0 \\ 1 & 0 & 0 & 0 \\ 0 & 0 & 0 & 1 \\ 1 & 0 & 0 & 0 \\ 0 & 0 & 1 & 0 \end{bmatrix}. \qquad (13)$$

The cost of annual energy losses is evaluated by:

$$C_{E\,lossy} = \left(\frac{1}{N_y}\right)\sum_{Z=1}^{N_y}\left([\mathrm{S_Z}]_{8760\times \mathrm{N_S}} \times [\mathrm{P_{lossy}}]_{\mathrm{N_S}\times 1}\right)^{\mathrm{T}} \times \mathrm{C}_{8760\times 1} \quad (14)$$

Where, C_{Elossy} is the cost of annual energy losses for year y.

Vector represents the hourly energy price in \$/kWh for the 8760 hours. The hourly market clearing prices of electric energy in 2010 from the IESO website are utilized as vector.
Finally, the NPV of the total cost of energy losses for the period under study is evaluated by

$$NPV_{loss} = \left(\frac{1}{N_y}\right)\sum_{y=1}^{\mathrm{Yrs}}\left(\frac{\mathrm{C_{E_{lossy}}}}{(1+\mathrm{d})^{\mathrm{y}}}\right)^{\mathrm{T}} \quad (15)$$

C. Cost of Interruption

The distribution network usually contains a mix of residential, commercial and industrial customers. Cost of interruption, which is known as the cost of damage (CDF), is not linear and varies according to the duration interruption as shown in Fig. 2, which shows the average cost of interruption estimates obtained as a function of duration for each customer sector. Since the CDF is not linear, as seen in Fig. 4.2, the outage cost cannot be evaluated analytically; thus, MCS is utilized. The outage cost is evaluated using:

$$costO_i = \left(\frac{1}{N_y}\right) \times \left(\sum_{k=1}^{N_{yi}} \mathrm{CDF(U_k)}\right) \times \mathrm{P_{loadi}} \quad (16)$$

Where,

$CostO_i$ is the outage cost of the load point 'i',
$CDF(U_k)$ is the outage cost corresponding to interruption event k,
N_i is total number of interruption events for load i,
$P_{load\ i}$ is the load point i average demand power.

In the above mentioned method to evaluate the contribution of DG to the interruption cost of different customers, the CDF is assumed to be constant for certain duration of outage. For example, the cost for interruption of 2 hours is the same for a certain customer type whenever this 2 hour interruption occurs during the day. To accurately express the effect of these DG units to reduce the cost of interruption, a modification of the CDF to be dependent on the time of the interruption event is assumed. For example, an interruption event of 4 hours at peak load costs more than the similar event at minimum load. Accordingly, the cost of interruption for a certain load point could evaluate using

$$costO_i = \left(\frac{1}{N_y}\right) \times \left(\sum_{\mathrm{k}=1}^{\mathrm{N_i}}\sum_{t=1}^{T_k} \mathrm{CDF(U_k)}\right) \times \mathrm{P_{loadi}} \times \frac{\mathrm{P_{pu\ i}(t)}}{\mathrm{T_k}} \quad (17)$$

Where,

T_k is the time in hours for outage event k,
$P_{pu\ i}(t)$is the per unit load power at time t for load point i .

The procedure to evaluate the cost of interruption is described as follows:

1. Divide the system into segments, according to the locations of protective devices as in.
2. For each segment, perform the following steps.
3. Define two sets: set (1), which includes all elements outside the segment whose failures cause power outage to the segment, and set (2), all elements within the segment whose failures cause outage to all load points within the segment.
4. Generate a two state model for each element within the two sets using the failure rate and repair time of each element, and combine these models to construct a two state model for each set.
5. Repeat steps 6 to 10 for each year in the period under study.
6. If there are no dispatch able DG units installed within the segment, go to step 9.
7. If the percentage of dispatch able DG units within the segment is below 60%, deactivate all renewable DG units within the segment.
8. For each outage event in set (1), check whether the islanding is successful or not. Yet, there is no standard for the required reserve margin within the island, as it depends on load variability, load magnitude, reliability requirements, types and availability of DG units. Therefore, it is assumed that the island is successful if the sum of the generated output power from all DG units within the segment is higher than or equals to a certain percentage of the load required power, which represents load

requirements, system losses, and reserve margin. This percentage is assumed to be 110% for dispatch able DG units only and 115% in case of renewable and dispatch able DG units connected to the system, as excess reserve margin is required due to variability and uncertainty of renewable DG units. Accordingly, the outage event in set (1) is modified to up time for successful islanding or left as down time for unsuccessful islanding.

9. Generate the final availability model for the segment under by the convolution of set (1) and set (2).
10. Evaluate the cost of interruption of using (17).
11. Evaluate the NPV of the cost of interruption using

$$\mathrm{NPV_{INT}} = \sum_{y=1}^{\mathrm{Yrs}} \frac{\sum_{i=1}^{n} \mathrm{Cost0}_{i_y}}{(1+d)^y} \qquad (18)$$

III. TEST SYSTEM

The distribution system consisting of IEEE 38 buses is considered to validate the proposed model associated with DG is applied to matlab simulation program. The obtained results in each scenario case are summarized in this section.

The line data and load data of the 11KV, 38-bus, radial distribution system are given in below in tableI.The diagram of IEEE-38 bus system under study is shown in fig. 2. To evaluate the DG's effect on reliability the islanded mode is introduced and the interruption cost is calculated.

TABLE I. System and load data for 38-bus test system

		Line Impedance in p.u.				Loads on to-node (p.u)		
F	T	R p.u.	X p.u.	L	S_L	P	Q	L_T
1	2	0.000574	0.000293	1	4.6	0.1	0.06	R
2	3	0.00307	0.001564	6	4.1	0.09	0.04	I
3	4	0.002279	0.001161	11	2.9	0.12	0.08	C
4	5	0.002373	0.001209	12	2.9	0.06	0.03	R
5	6	0.0051	0.004402	13	2.9	0.06	0.02	I
6	7	0.001166	0.003853	22	1.5	0.2	0.1	C
7	8	0.00443	0.001464	23	1.05	0.2	0.1	C
8	9	0.006413	0.004608	25	1.05	0.06	0.02	I
9	10	0.006501	0.004608	27	1.05	0.06	0.02	C
10	11	0.001224	0.000405	28	1.05	0.045	0.03	C
11	12	0.002331	0.000771	29	1.05	0.06	0.035	R
12	13	0.009141	0.007192	31	0.5	0.06	0.035	C
13	14	0.003372	0.004439	32	0.45	0.12	0.08	R
14	15	0.00368	0.003275	33	0.3	0.06	0.01	C
15	16	0.004647	0.003394	34	0.25	0.06	0.02	I
16	17	0.008026	0.010716	35	0.25	0.06	0.02	C
17	18	0.004558	0.003574	36	0.1	0.09	0.04	I
2	19	0.001021	0.000974	2	0.5	0.09	0.04	R
19	20	0.009366	0.00844	3	0.5	0.09	0.04	C
20	21	0.00255	0.002979	4	0.21	0.09	0.04	I
21	22	0.004414	0.005836	5	0.11	0.09	0.04	R
3	23	0.002809	0.00192	7	1.05	0.09	0.05	C
23	24	0.005592	0.004415	8	1.05	0.42	0.2	C
24	25	0.005579	0.004366	9	0.5	0.42	0.2	C
6	26	0.001264	0.000644	14	1.5	0.06	0.025	C
26	27	0.00177	0.000901	15	1.5	0.06	0.025	I
27	28	0.006594	0.005814	16	1.5	0.06	0.02	C
28	29	0.005007	0.004362	17	1.5	0.12	0.07	C
29	30	0.00316	0.00161	18	1.5	0.2	0.6	C
30	31	0.006067	0.005996	19	0.5	0.15	0.07	R
31	32	0.001933	0.002253	20	0.5	0.21	0.1	R
32	33	0.002123	0.003301	21	0.1	0.06	0.04	C
8	34	0.012453	0.012453	24	0.5	0	0	
9	35	0.012453	0.012453	26	0.5	0	0	
12	36	0.012453	0.012453	30	0.5	0	0	
18	37	0.003113	0.003113	37	0.5	0	0	
25	38	0.003113	0.003113	10	0.1	0	0	

F=From node, T=To node, L=Line number, S_L =Line MVA limit in p.u., P= Real MW load in p.u. ,Q= Reactive MVAr load in p.u., L_T =Load Type, R=Residential, I=Industrial, C=Commercial

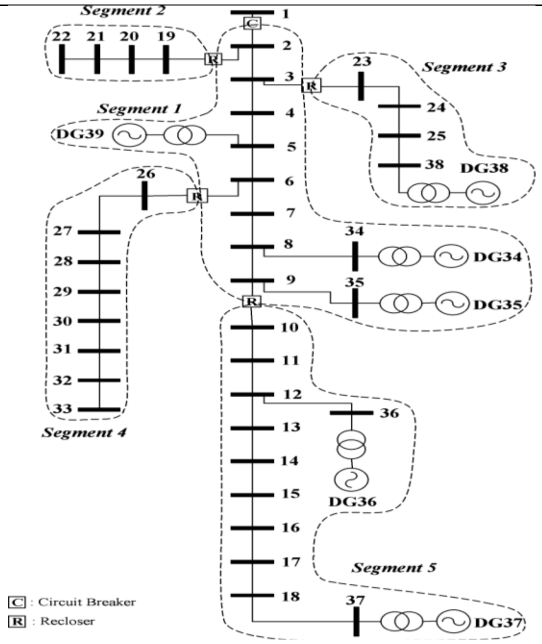

Fig.2. 38-bus radial distribution test system

TABLE II: The cost savings before and after DG Installation in Distribution Network

Detailed Results of Different Scenarios

DG type		no DG	dispatchable				wind				Wind and dispatchable							
scenario		a.0	B.1	B.2	B.3	B.4	c.1a	c.1b	c.2	c.3	d.1		d.2		d.3		d.4	
Objective			UG	EL	INT	UG+EL+INT	UG RF=3/8760	UG RF=6/8760	EL	UG+EL	UG		EL		INT		UG+EL+INT	
											Disp.	wind	Disp.	wind	Disp.	wind	Disp.	Wind
Installed DG units(MW) at candidate buses	DG 34	0	0.5	0.3	0	0.5	0	0.3	0.4	0.2	0.2	0	0.2	0	0	0	0.2	0
	DG 35	0	0	0	0	0	0	0.2	0	0	0.1	0.4	0	0.2	0	0	0.1	0.4
	DG 36	0	0	0.2	0.7	0	0	0.2	0.3	0.1	0.2	0	0.2	0	0.4	0.4	0.2	0
	DG 37	0	0.1	0.2	0.1	0.1	0.2	0.3	0.3	0.2	0.1	0	0.2	0	0.2	0.2	0.1	0
	DG 38	0	0.2	0.4	1.1	0.2	0.5	0.6	0.7	0.2	0.3	0.1	0.3	0.2	1.1	0.5	0.3	0.1
	DG 39	0	0.1	0.9	0	0.1	0	1.3	1.3	0	0	0.1	0.6	0.7	0	0.1	0	0.1
Total penetration(MW)		0	0.9	2	1.9	0.9	0.7	2.9	3	0.7	0.9	0.6	1.5	1.1	1.7	1.2	0.9	0.6
NPV of cost of system upgrade	lines upgrade($)	1341507.7	302806.97	597135.03	946653.8	302806.97	1242762.68	975172.38	1737198.4	1253026.4	357498.07		379657.9		1484235.11		357498.07	
	metering upgrade($)	0	0	40000	40000	0	0	40000	40000	0	0		40000		40000.00		0.00	
	protection upgrade($)	0	0	60000	60000	0	0	60000	60000	0	60000		240000		180000.00		60000.00	
	total($)	**1341507.7**	**302806.97**	**697135.03**	**1046653.8**	**302806.97**	**1242762.68**	**1075172.38**	**1837198.4**	**1253026.4**	**417498.07**		**659657.9**		**1704235.11**		**417498.07**	
	%saving	**0**	**77.43**	**48.03**	**21.98**	**77.43**	**7.36**	**19.85**	**-36.95**	**6.6**	**68.88**		**50.83**		**-27.04**		**68.88**	
NPV of cost of energy loss	**cost($)**	**234546.99**	**150416.01**	**116430.7**	**157915.2**	**150416.01**	**206033.44**	**171468.41**	**154664.36**	**198582.9**	**144029.46**		**121497.96**		**183626.44**		**144029.46**	
	%saving	**0**	**35.87**	**50.36**	**32.67**	**35.87**	**12.16**	**26.89**	**34.06**	**15.33**	**38.59**		**48.2**		**21.71**		**38.59**	
NPV of cost of interruption	segment1 ($)	106800	106800	106800	106800	129150	106800	106800	106800	106800	106800		106800		106800		106800	
	segment2 ($)	36000	36000	36000	36000	106800	36000	36000	36000	36000	36000		36000		36000		36000	
	segment3 ($)	195300	195300	190650	186000	36000	195300	195300	195300	195300	186000		186000		195300		186000	
	segment4 ($)	220800	220800	220800	220800	195300	220800	220800	220800	220800	220800		220800		220800		220800	
	segment5 ($)	129150	129150	126075	62115	220800	129150	129150	129150	129150	129150		128535		129150		129150	
	total ($)	**688050**	**688050**	**680325**	**611715**	**688050**	**688050**	**688050**	**688050**	**688050**	**678750**		**678135**		**688050**		**678750**	
	%saving	**0**	**0**	**1.12**	**11.09**	**0**	**0**	**0**	**0**	**0**	**1.35**		**1.44**		**0**		**1.35**	
total cost($)		**2264104.7**	**1141273**	**1401615.7**	**1792619**	**1141272.97**	**2136846.12**	**1834690.79**	**2579912.7**	**2139659.3**	**1189577.52**		**1189205.87**		**2355911.55**		**1189577.52**	
%total savings		**0**	**49.59**	**38.09**	**20.82**	**49.59**	**5.62**	**18.97**	**-13.95**	**5.5**	**47.46**		**47.48**		**-4.05**		**47.46**	

*disp.:dispachable DG's, wind:wind based DG's, UG:cost of upgrade, EL:cost of energy loss, INT:cost of interruption.

SIMULATION RESULTS

The outcomes of the allocation problem for a 20-year study period are shown in Fig.3 and the details are shown in TableII based on typical prices in dollars, for each scenario in Table III.

TABLE III.. Different Scenarios

Case	DG type	Scenario	Objective(s)	RF
A	No DG	A.0	No objectives (Base Case)	0
B	Disp.	B.1	UG	
		B.2	EL	
		B.3	INT	
		B.4	UG+EL+INT	
C	Wind	C.1.a	UG	3/8760
		C.1.b		6/8760
		C.2	EL	3/8760
		C.3	UG+EL	
D	Disp. And Wind	D.1	UG	
		D.2	EL	
		D.3	INT	
		D.4	UG+EL+INT	

* Disp.: Dispatchable DGs, Wind: Wind based DGs, UG: Cost of upgrade, EL: Cost of energy loss, INT: Cost of interruption, RF: risk factor.

For the case under study, the outcomes of the allocation problem for the cost of upgrade at zero RF are found to converge to the base case without DG units. Zero RF means that all combined wind and load states are considered regardless of their probabilities, as the LDC is taking no risk of over loading their lines.

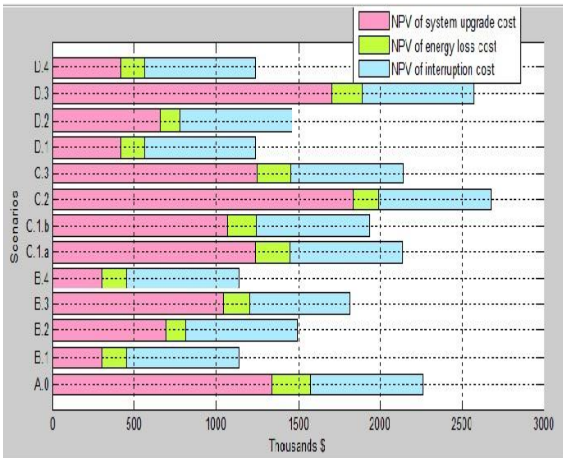

Fig.3. Results of different scenarios

Based on this result, the effect of variability and uncertainty of wind based DG result in equal or higher upgrades costs in distribution networks compared to the case without DG. The results presented, show the effectiveness of the proposed methodology in increasing the benefits of renewable DG in distribution networks. Thus the methodology introduces more accurate evaluation for the worth of the renewable DG connection.

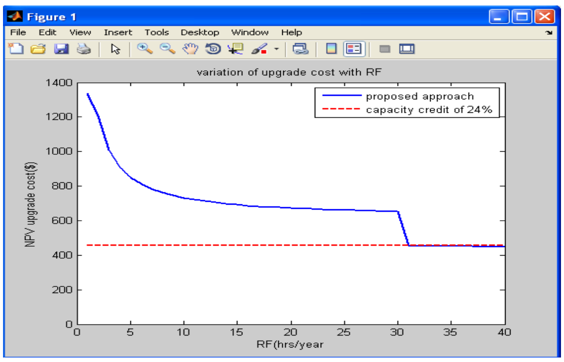

Fig.4. variation of upgrade costs with risk factor (RF)

CONCLUSION

In this project, a method is proposed to evaluate the worth of installing renewable distributed generation in distribution networks. Moreover, the work optimally allocates these DG units in the distribution network to maximize the worth of the connection to the local distribution company, as well as the customers connected to the system. The optimal allocation of DG is done by implementing a multi objective mixed integer programming based methodology. The economic benefits of optimal allocation of renewable DG and to maximize the delay of system upgrade investments, reduction of the energy losses cost & interruption cost are identified and calculated.

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MADHURI.N.S has received the B.Tech (Electrical And Electronics Engineering) degree from sree vidyanikethan engineering college, tirupathi in 2011 and has received the M.Tech (Electrical Power Systems) in srinivasa institute of technology, kadapa in 2014.