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Distribution System Annual Cost Minimization Using Clean Type Technologies

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Abstract: One of the basic obstacles in the deployment of clean technologies such as wind turbines or PV modules is their intermittent nature due to dependency on the wind speed and solar radiance. In fact, the authors in this paper aim to investigate the effect of clean technologies such as wind turbines and PV modules on the total and individual costs of the distribution system. In order to model the uncertain nature of clean technologies, we have proposed a probabilistic method in this study. So, a DG planning problem based on the hourly variations in wind speed and solar radiance is suggested to reduce the total cost of the distribution system. The hourly variations of the load like the hourly variations in wind speed and solar radiance is considered in this study. Also, all of the defined economic, technical and environmental functions are turned into cost functions. An encouraging and punishment mechanism is defined in addition to the other cost functions. The planning problem is formulated as mixed integer nonlinear programming problem (MINLP). The proposed method is applied on the 9-bus distribution system and the results show a significant reduction in annual costs of the distribution system using the DG units.

Keywords: PV module, Wind Turbine, Environmental function, Planning, Uncertainty, Probabilistic Simulation.

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1. Introduction

One of the main constraint in future generation expansion planning is emission limitation. Burning carbon has significant negative effects on the well-being of humans and eco-systems. Coal based electricity generation plants have the highest CO_2 emissions per kWh electricity as well as other pollutants at high levels, but still the market keen on using them due to their low cost of electricity generation and high availability of raw material. Thus, the governments and regulatory agencies at various levels have adopted specific policies to support clean technologies as alternative energy sources. Among all of the renewable technologies, only solar units and wind turbines, because of having no emission pollutants, are selected for this study. Economical operation [1], reliability improvement [2], energy savings and environmental benefits of the renewable energy sources make utility planners to use it as a proper approach for distribution system optimal expansion strategy. Solar and wind energies are the cleanest energy resources. The availability of cheap and free abundant energy with minimum environmental dangers without producing pollutants or emissions associated with their production and use is one of the significant factors for favorable improvement in the quality of people's life. However, the wind and solar resources are inherently intermittent and uncertainty of power availability is one of the major problems for the deployment of wind and solar energy into the electricity networks. Hence, it is important to model the renewable energies in a proper manner including the related uncertainties.

Proper planning of clean type technologies into existing distribution system plays a significant role for the improvement of the system performance. Distributed generation expansion planning (DGEP) has been frequently reported in the studies around the world. Fig.1 shows a brief classification of the last studies. According to this figure, the objective function in these studies is categorized into the technical and economic functions. As a matter of fact, these articles have focused on finding the best place and the best size of the DG units to improve the technical parameters such as reducing the power loss [3], improving the voltage profile [3,4] or the voltage stability of the distribution system [3,5] and increasing the reliability of supply [2,6] or they have analyzed the impact of the DG units on the technical indices of the distribution system such as the harmonic levels [7], power quality indices [8], loadability of the feeders [9] or the short circuit level of the buses of the distribution system [10]. Generally, studies in this field have not worked on the DG planning problem and they have typically concentrated on the sizing and allocation of the DG units. The objective function in nearly all of these studies is technical function, while the main purpose of the distribution system planners is to find a solution with the highest profit or the lowest cost. Also, the remaining papers which have focused on economic parameters have only covered some of the economic functions. Thus, with regard to the significance of the DG planning problem, we have presented a DG planning problem using economic function in a year.

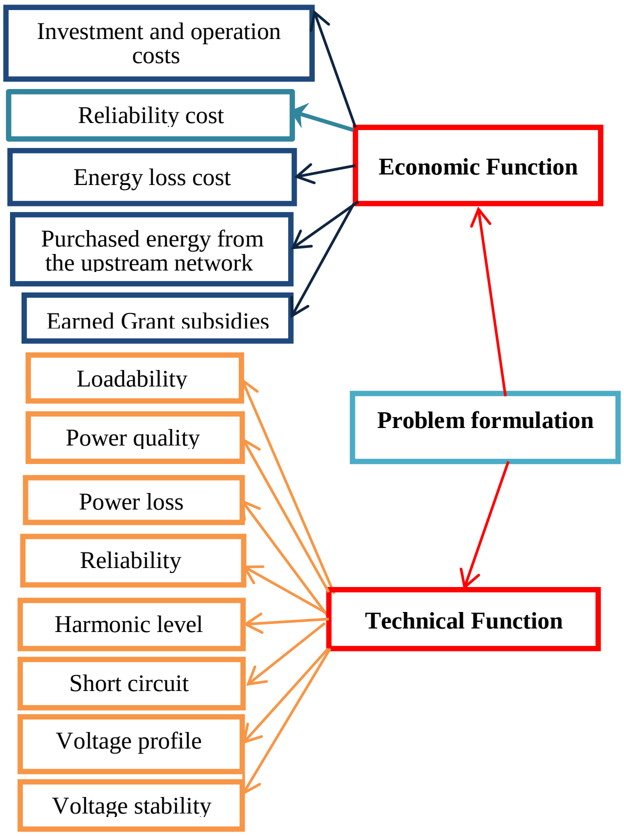

Fig.1. A brief classification of the last studies

Here in this paper, a new way of modeling the stochastic nature of the output power of the wind turbines and PV modules is presented. The proposed method is based on the probability rules and the historical gathered data of the wind speed and solar radiance during the last years. Besides, all of the defined technical, economic and environmental functions are considered in the final objective function of the presented DG planning problem. The aim of the presented DG planning problem is to reduce the total cost of the distribution system. We will also analyze if the clean technologies have a positive effect on the total cost of the distribution system or not. The total cost of the distribution system using the wind turbines and PV modules is to be compared with the use of each of the clean technologies solely. In addition, the influence of applying each of the clean technologies solely or together are compared with the non-DG state. Actually, in this study, due to the stochastic nature of the wind speed and solar radiance, an hourly planning is proposed for the planning of the clean units.

All of the economic, technical and environmental parameters and the encouraging and punishment mechanisms are turned into cost functions. The technical parameters include the power loss, voltage violations and reliability of supply which are modeled with the energy loss cost, penalty costs of voltage violations and energy not supplied cost. The encouraging and punishment mechanisms are the grant subsidy functions because of using clean technologies and the penalty costs because of voltage violations and energy not supplied. The produced emissions of the conventional generation which are defined as the environmental parameter are turned into emission taxes. The economic parameter includes the upgrading cost, purchased energy cost from the transmission system and the earned grant subsidies. It is worthy to note that in this paper, the distribution system company (DISCO) is not the owner of the DG units and it is only the owner of the distribution system and the operator of the renewable resources. Therefore, the investment and operation costs of the DG units are excluded from the costs of the distribution system company.

The solving process is based on defining the different possible states of clean technologies' generations for each hour covering all states of power generations. All combinations of the different generation's states of the different DG types are considered with the related probabilities. The total cost is calculated with the sum of all of the individual costs multiplied in their probabilities. Finally, the optimum places and sizes of the DG units are determined based on minimizing the total cost. The complete procedure of the proposed probabilistic method will be presented in the next section. The problem is formulated as mixed integer nonlinear programming (MINLP) and is solved using the GAMS software. The hourly variations of the load profile as well as the hourly variations in probability density functions of wind speed and solar radiance is considered in order to be close to reality.

2. Problem Formulation

An average-day in each season of a year is defined as the representative for that season. Each average-day is divided into 24 time segments and each time segment is divided into different states of generation modes of clean technologies. The process of defining the average-day as the representative for each season is as follows:

1-The historical hourly data of wind speed and solar radiance were prepared for a number of years.

2-The hourly mean solar radiance and wind speed for each season were calculated from the above historical data.

The motive behind considering one day as the representative of each season is to avoid the complexity of the planning problem. Thus, there is totally 96 time segments for a year (24 time segments in the representative day of each season×4seasons=96 time segments). In each time segment, we have considered the different states of wind turbine and PV module output power. The solar radiance and wind speed are within specific limits. In order to avoid long calculations and simplicity of the problem, five steps for the solar irradiance as 0.2kW/m^2 and five steps for the wind speed as 2m/s have been chosen. The discrete sizes for the wind turbines are not considered. However, because of the very small sizes of the standard PV modules, this assumption is not important in calculating the appropriate sizes for PV modules, for example the standard size of the PV modules in this paper is 75W, and if the proper size of the calculated solar unit is 1344kW, so 1792 PV modules will be required for this solar unit. Thus, the PV modules can be arranged in a manner to generate almost the power required. To apply the mentioned process to the planning problem, the probability generation matrix is defined and is explained in the next section. The complete flowchart of solving the presented DG planning problem is shown in fig.2. In order to compare all of the economic, technical and environmental parameters, 4 scenarios are defined and DG sizing and allocation is discussed in each scenario. The scenarios are as follow:

Scenario#1: The reference scenario in which no renewable resources are located in the distribution system. **Scenario#2**: Reducing the total costs considering wind and solar based DGs. **Scenario#3**: Reducing the total costs considering only wind based DGs. **Scenario#4**: Reducing the total costs considering only solar based DGs.

2.1. Organizing Probability Generation Matrix (M_{PG})

A four column matrix called probability generation matrix was constructed in this section. The first and the second column of this matrix belong to the wind turbine and solar unit generation states based on the percentage of their rated power. The rows of this matrix are consisted from all of the combinations of wind turbine and solar unit generation states. The third column corresponds to the probability of each row (each state of wind turbine and solar unit generation) which is calculated from Eq.1. The values in this column are calculated by multiplying the wind turbine and solar unit output powers' probabilities.

$$M_{PG,3}^{r} = P\{M_{PG,1}^{r}\} \times P\{M_{PG,2}^{r}\} \quad (1)$$

Where $M_{PG,\lambda}^{r}$ represents the r^{th} row and λ^{th} ($\lambda = 1,2,3,4$) column of matrix M_{PG}. $P\{M_{PG,\lambda}^{r}\}$ is the probability of occurrence of the element in r^{th} row and λ^{th} column of matrix M_{PG}. The fourth column of this matrix is as the same as the third column except that the forced outage rate is considered in calculating the probabilities. Forced Outage Rate ($F.O.R.$) is an inseparable feature of any production system, a result of hardware failure of renewable resources which results in an outage of the unit, so the output power of the unit will be zero. Eq.2 shows the probability of occurrence of each state of WT and PV generations considering $F.O.R.$

$$P\{M_{PG,\lambda(=1,2)}^{r,fail}\} = \begin{cases} P\{M_{PG,\lambda(=1,2)}^{r}\} \times (1 - F.O.R) & ,r \neq l \\ P\{M_{PG,\lambda(=1,2)}^{l}\} + F.O.R \times \sum_{r=1,r\neq k}^{ns} P\{M_{PG,\lambda(=1,2)}^{l}\} & ,r = l \end{cases} \quad (2)$$

As seen on Eq.2, two relations are considered for the probability of each state of WT and PV generations considering $F.O.R$. The second relation only is used for the l^{th} state (row) that the output power of the DG is zero. Unavailability of the renewable technology includes the hours that the renewable resource is working out of operating range and the hours that the DG is in forced outage time. It should be noted that the wind speed states and the solar irradiance states are independent. Hence, the probability of each state (row) of the M_{PG} matrix in the fourth column considering $F.O.R.$ is as follow:

$$M_{PG,4}^{r} = P\{M_{PG,1}^{r,fail}\} \times P\{M_{PG,2}^{r,fail}\} \quad (3)$$

In order to clarify the above explanations on building the probability generation matrix, an example is shown in Table2. Table1 shows the WTs and PV modules states with the related probabilities. The probabilities of WTs and PV modules generation states considering $F.O.R.$ is also calculated and shown in this table. The $F.O.R.$ in this example is considered to be 0.02.

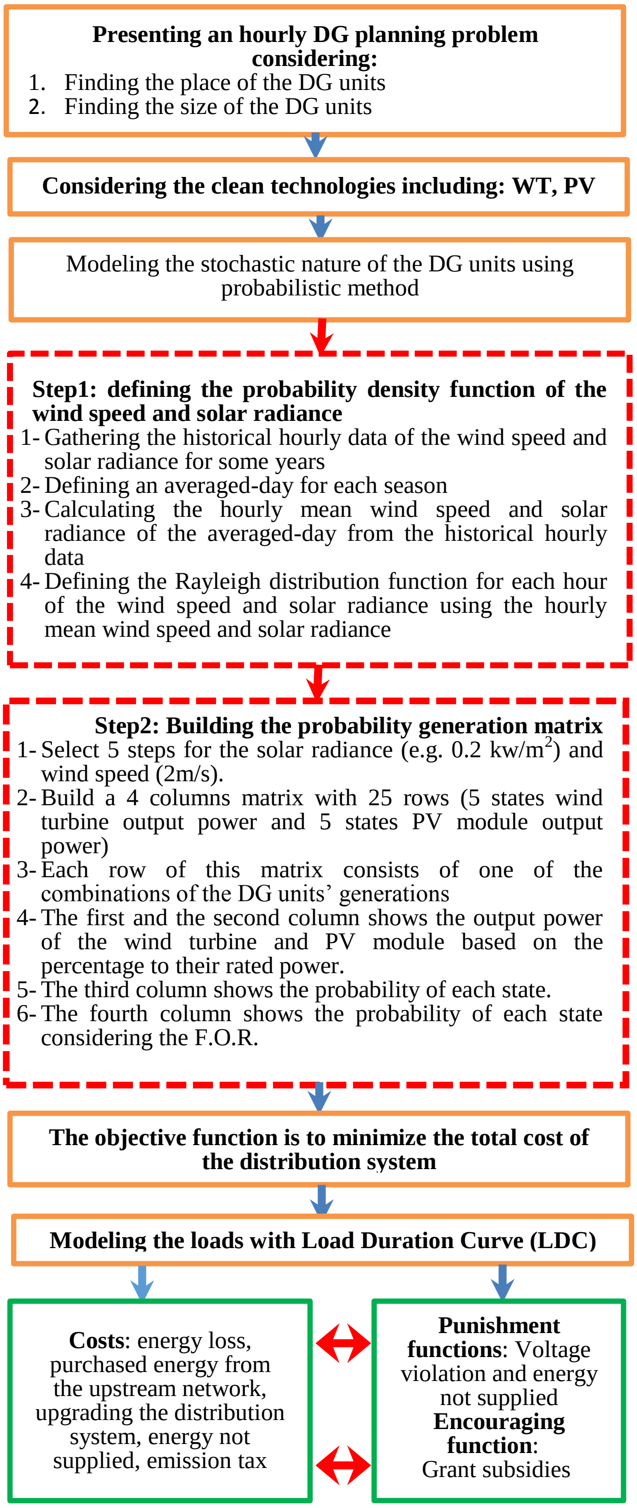

Fig.2. Flowchart of solving the DG planning problem

Table 1. The WT and PV modules generation states data

Generation states (percentage of rated power)	Probability	Probability (considering F.O.R)
WT		
0	0.35	0.35+0.02×(0.45+0.2)=0.363
0.5	0.45	0.45×(1-0.02)=0.441
1	0.2	0.2×(1-0.02)=0.196
PV		
0	0.1	0.1+0.02×(0.65+0.25)=0.118
0.6	0.65	0.65×(1-0.02)=0.637
1	0.25	0.25×(1-0.02)=0.245

Table 2. The probability generation matrix

WT generation states (percentage of the rated power)	PV generation states (percentage of the rated power)	Probability	Probability considering F.O.R
0	0	0.35×0.1	0.363×0.118
0	0.6	0.35×0.65	0.363×0.637
0	1	0.35×0.25	0.363×0.245
0.5	0	0.45×0.1	0.441×0.118
0.5	0.6	0.45×0.65	0.441×0.637
0.5	1	0.45×0.25	0.441×0.245
1	0	0.2×0.1	0.196×0.118
1	0.6	0.2×0.65	0.196×0.637
1	1	0.2×0.25	0.196×0.245

2.2. DG Units and Load Modeling

In order to come close to real conditions, the probability density functions of wind speed and solar radiance are defined for each hour. The Rayleigh density function is used to model the PDF of wind speed and solar radiance. The Rayleigh distribution function is a specific shape of the Weibull function shown in Eqs.4, 5 when k=2.

$$f(x) = \left(\frac{k}{c}\right) \times \left(\frac{x}{c}\right)^{k-1} \times exp\left[-\left(\frac{x}{c}\right)^{k-1}\right] \quad (4)$$

$$x_m = \int_0^{\infty} x \times f(x) \times dx = \int_0^{\infty} \left(\frac{2x^2}{c^2}\right) \times exp\left[-\left(\frac{x^2}{c^2}\right)\right] \times dx = \frac{\sqrt{\pi}}{2}c \ \rightarrow c = 1.12838x_m \quad (5)$$

In this equation, k is the shape parameter and c is the scale index. The wind speed and solar radiance is replaced with x in Eq.4. x_m is the mean value of variable x. As seen in this equation, the scale index c is obtained from the mean value of variable x (wind speed or solar radiance). Thus, in order to model the wind speed and solar radiance for each hour, the hourly mean wind speed and solar radiance data is needed. The historical mean wind speed and solar radiance data shown in Figs.3,4, is used to model the wind speed and solar radiance Rayleigh distribution function for each hour.

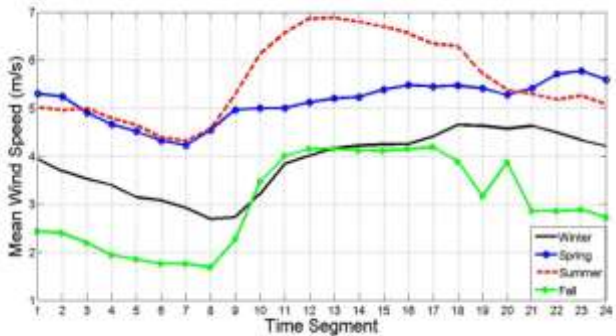

Fig.3. The mean wind speed data used in this paper

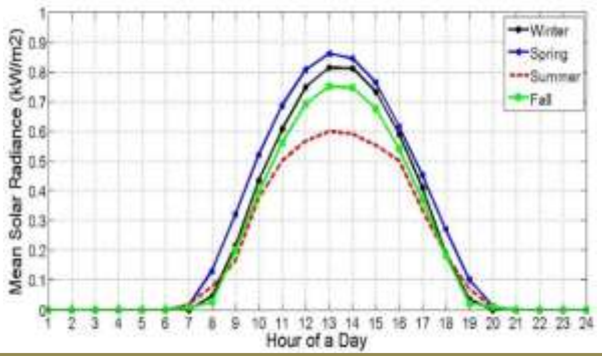

Fig.4. The mean solar radiance data used in this paper

Therefore, the probability generation matrix should be constructed for each hour (the values in 3rd and 4th columns are variable in the generation load matrices). The PV modules and wind turbine output power formulations are shown in Eqs.6 to 12 [11, 12]. In this study, the loads are modeled with IEEE-RTS system [11] shown in Fig.5. This system shows the hourly peak load as a percentage of the peak load.

$$P_S(s) = N \times FF \times V_{oc}(s) \times I_{sc}(s) \quad (6)$$

$$FF = \frac{V_{MPP} \times I_{MPP}}{V_{oc,STC} \times I_{sc,STC}} \quad (7)$$

$$V_{oc}(s) = V_{oc,STC} - K_v \times T_{Cs} \quad (8)$$

$$T_{Cs} = T_{Am} + \frac{s}{s_r} \times (T_{nco} - T_{Air}) \quad (9)$$

$$I_{sc}(s) = \frac{s}{s_n} \times \left[I_{sc,STC} + K_i \times \left(T_{Cs} - T_{C,STC}\right)\right] \quad (10)$$

$$N = N_s \times N_p \quad (11)$$

$$P_V(V) = \begin{cases} 0 & 0 \le V \le V_{ci} \\ P_{rated} \times \frac{V - V_{ci}}{V_r - V_{ci}} & V_{ci} \le V \le V_r \\ P_{rated} & V_r \le V \le V_{co} \\ 0 & V_{co} \le V \le \infty \end{cases} \quad (12)$$

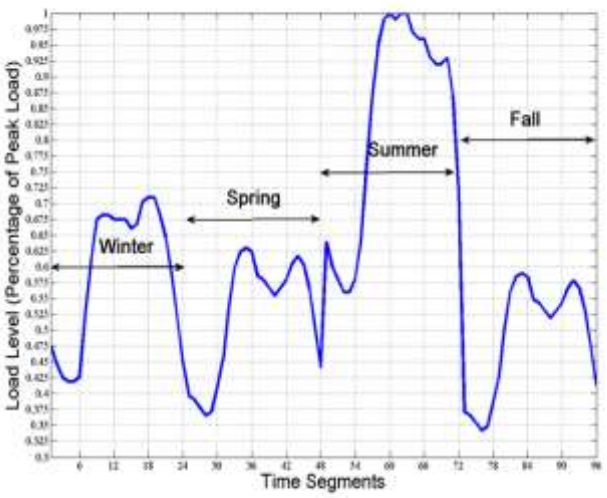

Fig.5. The hourly peal load variations in a year

3. Mathematical Model

3.1. Objective Functions

In this paper the distribution system company is responsible for supplying the load demand, the operation of the DG units and the distribution system management. The final objective function which is minimized is the total costs of the distribution system shown in Eq.13.

$$Cost\ (Obj.Function) = CEL + CE_{tr} + CE_{wind} + CE_{pv} + CENS + CU + CET + PCVD + PCCI - GS_{wind} - GS_{pv} \quad (13)$$

3.1.1. Cost Function of Energy Losses (CEL)

$$P_{loss}^{r,h,s} = P_{G1}^{r,h,s} + \sum_{i=1}^{N_{bus}}\left[P_{rated}^{wind}(i) \times M_{PG,1}^{r,h,s} + P_{rated}^{solar}(i) \times M_{PG,2}^{r,h,s} - LL^{h,s} \times P_d(i)\right] \quad (14)$$

$$CEL = \left(\sum_{s=1}^{4}\sum_{h=1}^{24}\sum_{g=1}^{gtot} P_{loss}^{r,h,s} \times M_{PG,4}^{r,h,s} \times 90\right) \times price_{loss} \quad (15)$$

Where $M_{PG,1}^{r,h,s}$, $M_{PG,2}^{r,h,s}$ and $M_{PG,4}^{r,h,s}$ represents the first, the second and the fourth column of probability generation matrix in state r (r^{th} row) , hour h and season s respectively.

3.1.2. Cost Function of Purchased Energy ($CEtr$, CE_{wind} ,CE_{pv})

$$CEtr = \left(\sum_{s=1}^{4}\sum_{h=1}^{24}\sum_{r=1}^{rtot} P_{G1_g}^{h,s} \times M_{PG,4}^{r,h,s} \times 90\right) \times price_{tr} \quad (16)$$

$$CE_{wind} = \sum_{i=1}^{N_{bus}} P_{av}^{wind}(i) \times 8760 \times price_{dg} \quad (17)$$

$$CE_{pv} = \sum_{i=1}^{N_{bus}} P_{av}^{solar}(i) \times 8760 \times price_{dg} \quad (18)$$

The average output power of the wind turbines and solar units are calculated using capacity factor. Capacity factor is defined as the ratio between the average output power and the rated power. The PDF of wind speed and solar radiance are defined hourly using the hourly mean wind speed and mean solar radiance profiles and are the same for all of the sites. Hence, an hourly capacity factor for each season is defined. The average output power of the wind turbine and solar units are calculated as Eqs.19, 20:

$$P_{av}^{wind}(i) = \frac{\sum_{s=1}^{4}\sum_{h=1}^{24} CF_{wind}^{h,s} \times P_{rated}^{wind}(i)}{96} \quad (19)$$

$$P_{av}^{solar}(i) = \frac{\sum_{s=1}^{4}\sum_{h=1}^{24} \times CF_{solar}^{h,s} \times P_{rated}^{solar}(i)}{96} \quad (20)$$

3.1.3. Cost Function of Energy not Supplied (*CENS)*

$$ENS = \sum_{i,j} L_{ij} \times \lambda_{ij} \times \sum_{s=1}^{4}\sum_{h=1}^{24} \begin{cases} \left(P_{DG}^{h,s}(ij) - P_{lossz}^{h,s}\right) \times T_{res} + LL^{h,s} \times \left(P_D^{int}(ij) + P_{lossz}^{h,s}\right) \times T_{rep} \\ \quad if\ LL^{h,s} \times P_D^{int}(ij) + P_{loss}^{h,s} > P_{DG}^{h,s}(ij) \\ LL^{h,s} \times P_D^{int}(ij) \times T_{res} \\ \quad if\ LL^{h,s} \times P_D^{int}(ij) + P_{loss}^{h,s} < P_{DG}^{h,s}(ij) \end{cases} \quad (21)$$

$$P_{DG}^{h,s}(ij) = CF_{wind}^{h,s} \times \sum_{j \in is} P_{rated}^{wind}(j) + CF_{solar}^{h,s} \times \sum_{j \in is} P_{rated}^{solar}(j) \quad (22)$$

$$P_D^{int}(ij) = \sum_{j \in is} P_d(i) \quad (23)$$

$$CENS = price_{ENS} \times ENS \quad (24)$$

Where "*is*" is the buses in islanded zone after failing the branch between buses i, j. As seen above, two relations are considered in Eq.21. In the first relation, the islanded loads after failing the line between buses i, j ($LL^{h,s} \times P_D^{int}(ij)$) in addition to the islanded distribution system real power loss ($P_{lossz}^{h,s}$) are larger than the total DG capacity on the islanded section ($P_{DG}^{h,s}(ij)$); and the second relation is vice versa, in the second one, the islanded loads in addition to the islanded distribution system real power loss are smaller than the total DG capacity in the islanded section. In the first relation, part of the loads which is restored by the installed DG capacity is shown with $\left(P_{DG}^{h,s}(ij) - P_{lossz}^{h,s}\right)$ and the remaining loads which are repaired is shown with $LL^{h,s} \times P_D^{int}(ij) + P_{lossz}^{h,s}$. In the second relation, all of the loads are restored by the installed DG capacity. Because of the complexity and time consuming in calculating the real power loss in the islanded distribution system, the $P_{lossz}^{h,s}$ in each state is considered 5% of the related total load.

3.1.4. Cost Function of Distribution System Upgrades (*CU*)

Here in our study, only the investments are concerned that needed to replace the overloaded feeders or branches with the higher capacity ones.

$$CU = \sum_{ij} L_{ij} \times price_{uc} \times \begin{cases} 1 & if\ LF_{ij} > SL_{ij} \\ 0 & if\ LF_{ij} < SL_{ij} \end{cases} \quad (25)$$

$$LF_{ij} = \frac{\sum_{S=1}^{4}\sum_{h=1}^{24} LF_{ij}^{s,h}}{96} \quad (26)$$

The line flows for each branch in all load levels for each generation states are obtained and then the average value between the 96 calculated line flows is computed (by dividing to 96=24 time segment ×4 season). Finally, if the calculated average line flow for each branch becomes larger than the capacity limit of the related line (SL_{ij}), the line should be replaced with a higher capacity one.

3.1.5. Cost Function of Emission Pollutants (CET*)*

Since the DISCO has the option of using the non-pollutant power producers (clean technologies), so the DISCO should pay an emission tax because of supplying the customer demands from conventional power generation instead of buying the electricity from non-pollutant producers. As a result, the DISCO tries to use the power generators with lower rate of emission pollutants. Eqs.27 and 28 show the calculation process. The emission pollutants in this paper are CO_2, NO_x, and SO_2.

$$CET_r^{h,s} = (Em_{co2}^{conv} \times Ech_{co2} + Em_{Nox}^{conv} \times Ech_{Nox} + Em_{so2}^{conv} \times Ech_{so2}) \times P_{G1_r}^{h,s} \quad (27)$$

$$CET = \sum_{S=1}^{4}\sum_{h=1}^{24}\sum_{r=1}^{rtot} CET_r^{h,s} \times M_{PG,4}^{r,h,s} \times 90 \quad (28)$$

The CO_2 emission tax that should be paid by the DISCO is modeled in Fig.6. As we see in this model, the emission tax per kg of pollutants is linearly increased based on rising the output power of the power generators. The NO_x and SO_2 emission tax per kg of pollutants are constant in all values of output powers.

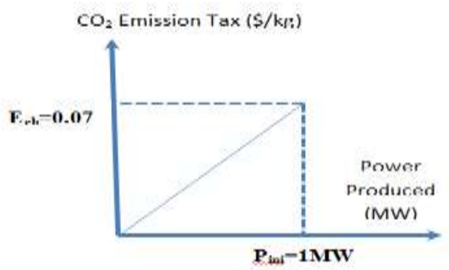

Fig.6.The proposed model for CO_2 emission tax

3.1.6. Cost Function of Penalties

3.1.6.1. Penalty Cost of Voltage Deviations (PCVD)

In this section, a penalty function is defined [13] to determine the penalty cost of the DISCO because of the deviation voltage in customer centers. This penalty function shows how far the solution is away from the feasibility region. The voltage deviation penalty cost is shown in Fig.7. The voltage deviation penalty cost based on the model shown in Fig.7 is defined in Eqs.29 to 31.

$$PCVD_r^{h,s} = \sum_{i=1}^{N_{bus}} fine \times \begin{cases} 1 & V_r^{h,s}(i) \le 0.90 \\ \left(19 - 20V_r^{h,s}(i)\right) & 0.90 \le V_r^{h,s}(i) \le 0.95 \\ 0 & 0.95 \le V_r^{h,s}(i) \le 1.05 \\ \left(20V_r^{h,s}(i) - 21\right) & 1.05 \le V_r^{h,s}(i) \le 1.10 \\ 1 & 1.05 \le V_r^{h,s}(i) \end{cases} \quad (29)$$

$$PCVD = \sum_{S=1}^{4}\sum_{h=1}^{24}\sum_{r=1}^{rtot} PCVD_r^{h,s} \times M_{PG,4}^{r,h,s} \times 90 \quad (30)$$

$$PCVD(i) = \sum_{s=1}^{4}\sum_{h=1}^{24}\sum_{r=1}^{rtot}\left[fine \times \begin{cases} 1 & V_r^{h,s}(i) \le 0.90 \\ \left(19 - 20V_r^{h,s}(i)\right) & 0.90 \le V_r^{h,s}(i) \le 0.95 \\ 0 & 0.95 \le V_r^{h,s}(i) \le 1.05 \\ \left(20V_r^{h,s}(i) - 21\right) & 1.05 \le V_r^{h,s}(i) \le 1.10 \\ 1 & 1.05 \le V_r^{h,s}(i) \end{cases} \right] \quad (31)$$

3.1.6.2. Penalty Cost of Customer Interruptions (PCCI)

In order to improve supply reliability of the customers and avoid customer interruptions, two reliability objective functions are defined. The first is the cost of energy not supplied considered in section 3.1.3. The second objective function is penalty cost of customer interruptions. The penalty cost of customer interruption is the fine that should be paid by the DISCO [14] and is defined in Eq.32.

$$PCCI = fine_{ENS} \times ENS \quad (32)$$

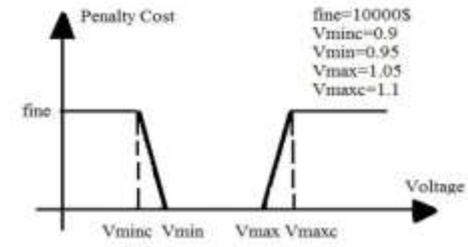

Fig.7. Penalty cost function

3.1.7. Cost Function of Grant Subsidies

The grant subsidy function is based on the pollution not emanated due to employing clean technologies [1]. In this paper, this grant subsidy is paid to the DISCO due to providing the customer demand from the clean technologies instead of the conventional power plants. Eqs.33 and 34 show the grant subsidy function is earned by the DISCO.

$$GS_{wind} = (Em_{co2}^{conv} \times Ech_{co2} + Em_{Nox}^{conv} \times Ech_{Nox} + Em_{so2}^{conv} \times Ech_{so2}) \times \sum_{i=1}^{N_{bus}} P_{av}^{wind}(i) \times GREnP \times 8760 \quad (33)$$

$$GS_{pv} = (Em_{co2}^{conv} \times Ech_{co2} + Em_{Nox}^{conv} \times Ech_{Nox} + Em_{so2}^{conv} \times Ech_{so2}) \times \sum_{i=1}^{N_{bus}} P_{av}^{solar}(i) \times GREnP \times 8760 \quad (34)$$

3.2. DG Expansion Planning Constraints

- **Power Flow Equations**

$$P_{G_r}^{h,s}(i) + P_{rated}^{wind}(i) \times M_{PG,1}^{r,h,s} + P_{rated}^{solar}(i) \times M_{PG,2}^{r,h,s} - LL^{h,s} \times P_d(i) = \sum_{j=1}^{N_{bus}} V_r^{h,s}(i) \times V_r^{h,s}(j) \times Y(i,j) \times cos\left(\delta_r^{h,s}(i) - \delta_r^{h,s}(j) - \theta(i,j)\right) \quad (35)$$

$$Q_{G_r}^{h,s}(i) - LL^{h,s} \times Q_d(i) = \sum_{j=1}^{N_{bus}} V_r^{h,s}(i) \times V_r^{h,s}(j) \times Y(i,j) \times sin\left(\delta_r^{h,s}(i) - \delta_r^{h,s}(j) - \theta(i,j)\right) \quad (36)$$

- **Maximum Penetration of Wind and Solar Based DG Units in the System**

$$\sum_{i=1}^{N_{bus}}\left(P_{av}^{wind}(i) + P_{av}^{solar}(i)\right) \le pen\_level \times \sum_{i=1}^{N_{bus}} P_d(i) \quad (37)$$

Where *Pen_level* is the penetration level of the DG units in percentage of the total load. More than one type of renewable resource can be placed in each bus. The DGs are assumed to be operated at unity power factor. The power factor of all loads is 0.9.

4. Simulation Results

The defined problem is tested on the typical 9-bus distribution system [15] shown in Fig.8. The technical data of this network and the required data to solve this problem are considered in [1,15,16]. All network nodes except the substation bus are considered as candidate sites for DG placement.

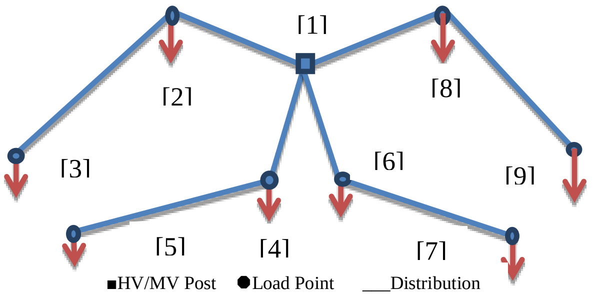

Fig.8.The 9 bus test distribution system

The maximum penetration of average and rated output power of the clean technologies in each bus is considered 10MW. Eqs.37 and 38 show the mathematical order of the considered assumptions.

$$P_{av}^{wind}(i) + P_{av}^{solar}(i) \leq 10MW \quad (38)$$

$$P_{rated}^{wind}(i) + P_{rated}^{solar}(i) \leq 10MW \quad (39)$$

As it is explained in the previous sections, in the probabilistic method, we have considered all of the possible states of DG generations with the related probabilities. So the results of the planning problem turned out to be very close to reality. Postulating the wind turbines and solar units with their average sizes in load flow equations lead to inexact results. In this state, the DG units have a constant output power during a day, but this is not a true assumption. The PV modules' and WTs' output power have dependency on many factors such as the season of a year, the hour of a day, the weather conditions etc. Here, the DG planning problem is solved considering the WTs and PV modules with their average size in load flow equations and it is called the "traditional method". The results will be compared with the proposed probabilistic method in the coming sections, Table 3. As explicated in table3, the results of the traditional and the probabilistic methods have significant differences with each other in all of the defined scenarios. For example, in scenario#4, the size of the PV modules for all of the buses is calculated 10 MW in the traditional method which equals to the maximum penetration of the solar units in each bus. Therefore, the total cost calculated by the traditional method turned out to be very lower than the total cost calculated by the probabilistic method which is not a favorable result because only one of the generation states is considered that is not real condition.

In the next sections, the results of the DG planning using probabilistic method are discussed. The summary of the results for all of the scenarios is depicted in Table4. It should be noted that the sizes of the renewable resources shown in table3 are the rated values. All of the figures are related to the Eq.39.

4.1. Energy Loss Cost

As seen in the simulation results shown in Table5, the energy loss cost in a year, using both of wind and solar units is reduced by 28.06% in comparison with the base case in scenario #1. The energy loss cost in a year is reduced by 23.91% in comparison with the reference state where only wind turbines are used in scen#3. DG planning considering only solar units cause a 20.92% reduction in yearly energy loss in comparison with the base case. Figs.9,10 show the power loss during a year and the seasonal energy loss for all of scenarios respectively. Fig.11 shows the percentage of power loss reduction during a year for all of the scenarios. As seen in Fig.9, the 4th scenario (only PV) has the same hourly power loss with the scenario#1 (non-DG state) in some hours of the year. The reason is that in these hours, the output power of the PV modules is zero (for example from 00:00 a.m. to 6:00 a.m. and from 7:00 p.m. to 24:00 p.m.), so during these hours, the system acts the same as a non-DG system.

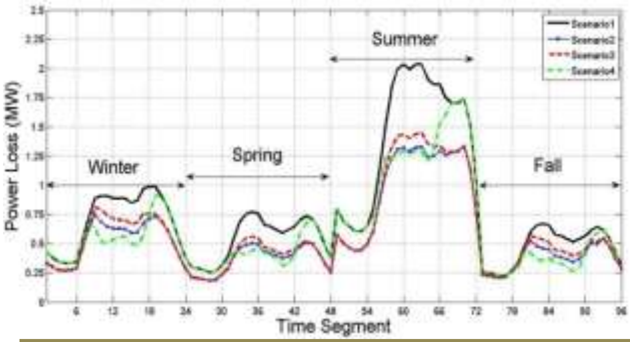

Fig.9. Hourly power Loss during a year

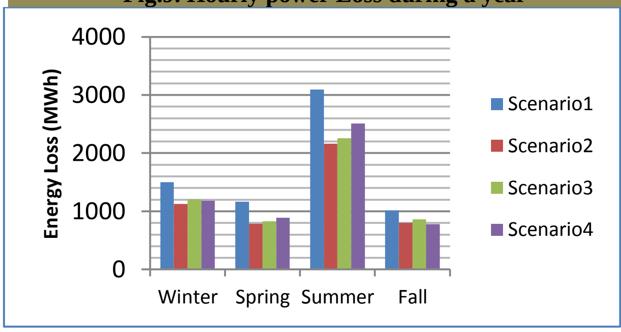

Fig.10.Seasonal energy loss during a year

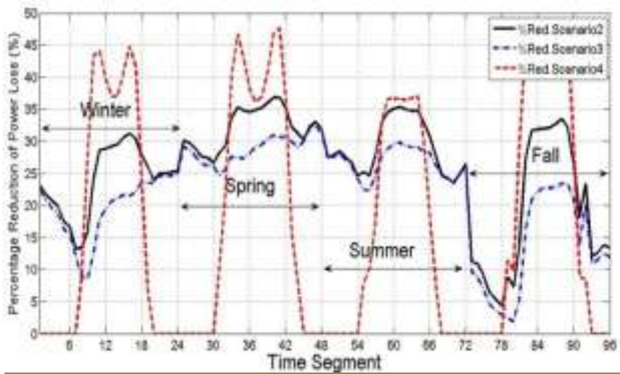

Fig.11.Percentage of hourly power loss reduction during a year

Table 3. DG planning results with traditional and probabilistic methods

Scenario → ↓ bus	#1 (base case: non-dg)	#2 (wind & PV)						#3 (wind only)			#4 (PV only)		
		Probabilistic				Traditional		Probabilistic		Traditional	Probabilistic		Traditional
		Av. Pent.		Rated Pent.				Av. Pent.	Rated Pent.		Av. Pent.	Rated Pent.	
		Wind	PV	Wind	PV	Wind	PV	Wind	Wind	Wind	PV	PV	PV
2	0	0	0	0	0	3.267	0	0	0	2.482	0	0	10
3	0	9.237	3.799	7.543	2.457	10	0	9.187	9.187	10	10.366	10	10
4	0	0	0	0	0	0	0	0	0	0	0	0	10
5	0	0	0	0	0	7.568	0	0	0	7.568	2.436	2.492	10
6	0	0	0	0	0	8.158	1.842	0	0	10	0	0	10
7	0	2.813	0	2.972	0	10	0	2.810	2.810	10	3.623	3.909	10
8	0	0	0	0	0	9.657	0.343	0	0	10	0	0	10
9	0	5.494	1.136	7.016	2.451	10	0	5.547	5.547	10	5.296	5.306	10
Total installed DG (MW)	0	17.544	4.935	17.531	4.908	58.65	2.185	17.544	17.544	60.05	21.721	21.707	80
Total installed DG (MW)	0	22.479		22.439		60.835		17.544	17.546	60.05	21.721	21.707	80
Total cost $\times 10^8$($)	5.5553	3.8939		3.8957		1.8365		4.1819	4.1819	1.8366	4.4172	4.4176	2.2761

Table 4. The summary of results of costs in average and rated penetration

Scenario# → ↓ Cost Func.	#1 (base case: non-dg)	#2 (Wind & PV)		#3 (Wind Only)		#4 (PV Only)	
		Av. Pent.	Rated Pent.	Av. Pent.	Rated Pent.	Av. Pent.	Rated Pent.
Energy Loss Cost ($) $\times 10^5$	4.7439	3.4033	3.4127	3.6096	3.6096	3.7582	3.7514
Purchased Energy Cost ($) $\times 10^7$	1.9070	1.7878	1.7881	1.8169	1.8169	1.8265	1.8265
Energy not Supplied Cost ($) $\times 10^7$	2.1132	1.6412	1.6156	1.7219	1.7219	1.8675	1.8667
Upgrading Cost ($) $\times 10^7$	6.4500	6.4500	6.4500	6.4500	6.4500	6.4500	6.4500
Penalty Cost ($) $\times 10^7$	2.9719	1.6587	1.6769	1.8481	1.8481	2.0239	2.0246
Emission Tax Cost ($) $\times 10^8$	4.2064	2.8197	2.8221	3.0649	3.0649	3.2522	3.2526
Subsidy Cost ($) $\times 10^6$	0	8.2967	8.2843	7.0347	7.0347	5.5536	5.5497
Total Cost ($) $\times 10^8$	5.5553	3.8939	3.8957	4.1819	4.1819	4.4172	4.4176

Table 5. The percentage of cost reduction compare to the reference state

Scenario#→ ↓Cost Func.	%Red. In #2 (Wind & PV)		%Red. In #3 (Wind Only)		%Red. In #4 (PV Only)	
	Av. Pent.	Rated Pent.	Av. Pent.	Rated Pent.	Av. Pent.	Rated Pent.
Energy Loss Cost	28.26	28.06	23.91	23.91	20.78	20.92
Purchased Energy Cost	6.25	6.23	4.72	4.72	4.22	4.22
Energy not Supplied Cost	22.34	23.55	18.42	18.42	11.63	11.66
Upgrading Cost	0	0	0	0	0	0
Penalty Cost	44.19	43.57	37.81	37.81	31.90	31.88
Emission Tax Cost	32.97	32.91	27.14	27.14	22.68	22.67
Total Cost	29.91	29.87	24.72	24.72	20.49	20.48

4.2. Purchased Energy Cost

As seen in Table5, the total cost of energy purchased by the DISCO in the reference state without any DG units is 1.9070×10^7 $. In the second scenario, the total cost of purchased energy is reduced by 6.23%. Part of the total cost of energy purchased by the DISCO is paid to the transmission system and the remaining should be paid to the DG owners. The total cost of purchased energy by the DISCO in the third scenario is reduced by 4.72% in comparison with the base case. DG planning considering only solar units cause a 4.22% reduction in the total cost of electricity paid by the DISCO. Fig.12 shows the total amount of energy purchased by the DISCO from the transmission system and the DG owners in a year for all of the scenarios. As shown in this figure, the least amount of the purchased energy belongs to the second scenario.

Fig.13 shows the hourly power purchased by the DISCO from the transmission system during a year for all of the scenarios. Fig.14 shows the percentage reduction of hourly power purchased from the transmission system for all of the scenarios during a year.

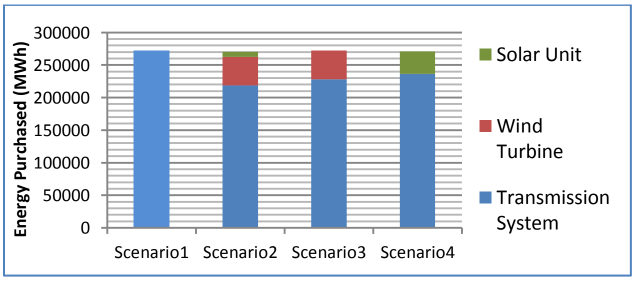

Fig. 12. Energy Purchased by the DISCO from the Transmission System and the DG owners

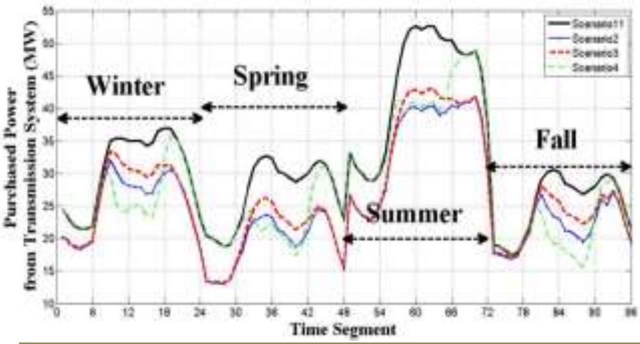

Fig.13. Hourly power purchased from the transmission system during a year

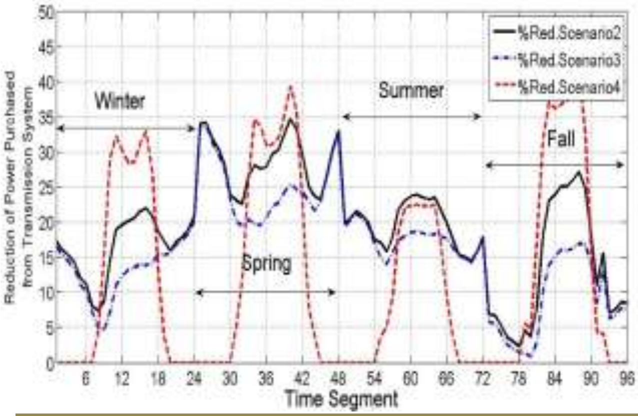

Fig.14. Percentage reduction of hourly power purchased from transmission system during a year

4.3. Energy not Supplied Cost

As seen in Table5, energy not supplied cost is decreased by 23.55%, 18.42% and 11.66% in comparison with the reference state in scens# 2, 3 and 4 respectively. Fig.15 shows the seasonal energy not supplied calculated for each scenario. Fig.16 shows the total energy not supplied for each scenario. The second scenario has the least ENS among all of the scenarios.

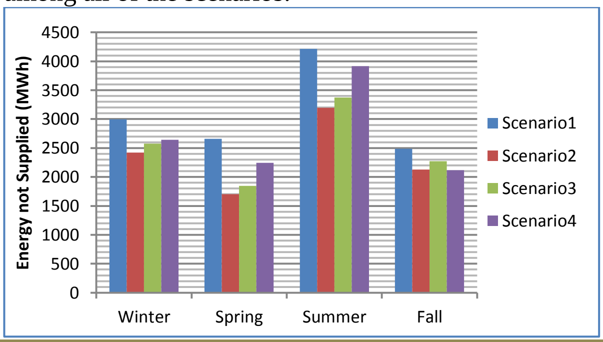

Fig.15. Seasonal energy not supplied during a year

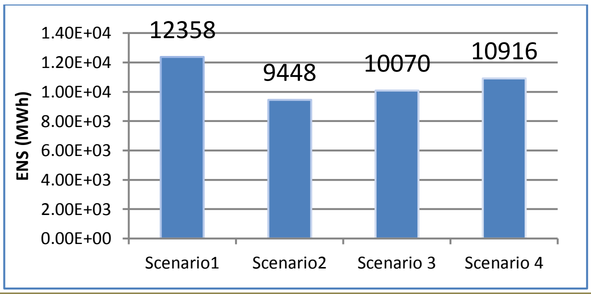

Fig.16. Energy not Supplied of each scenario

4.4. Upgrading Cost

As seen in Tables4,5, there is not any reduction in upgrading cost of the test distribution system because the test distribution system under study is a small distribution system and the capacity limit of the branches is very low (120 A).

4.5. Penalty Costs

Penalty costs include voltage deviation and energy not supplied penalties. As depicted in Table5, the penalty costs using solar units and wind turbines are reduced by 43.57% in comparison with the non-DG state. Penalty costs are decreased by 37.81% and 31.88% in comparison with the reference state considering wind turbines and solar units solely. Fig.17 shows the amount of individual and total penalty costs for each scenario in a year. Using both solar units and wind turbines result into a more reduction in penalty costs. The maximum reduction in voltage deviation penalty costs is occurred in the second scenario, so the voltage profile of the distribution system using both solar and wind units looks better. The hourly voltage deviation penalty cost during a year for all scenarios is shown in Fig.18. There is not any voltage violation in the autumn for the scenarios and a small number of voltage violations occurs in spring. The maximum voltage violations occurs in summer because of the higher levels of the load in this season. Fig.19 shows the amount of reduction in penalty costs in comparison with the reference state for scens# 2, 3 and 4. As seen in this figure too, the maximum reduction of the total penalty costs and the individual penalty terms occur using both solar units and wind turbines. This means that the better voltage profile and the less energy not supplied of the distribution system is obtained using both the DG types simultaneously. Fig.20 shows the reduction of voltage deviation penalty cost for each season and Fig.21 shows the hourly percentage of voltage deviation reduction in comparison with the reference state for all of the scenarios during a year. As seen in this figure, in spite of the low voltage deviation penalty cost in the spring in the base case (Fig.18), there is a peak point in voltage deviation penalty cost reduction using both wind turbine and solar units in spring, because the voltage deviation penalty cost in this time segment (hour 10 in spring) is reduced from 35.079 $ to o.481 $ (according to Fig.18) in scenario#2, so 98.63% reduction of voltage deviation penalty cost is seen in this hour. Fig.22 shows the contribution amount of each bus in the total voltage deviation penalty cost of each scenario.

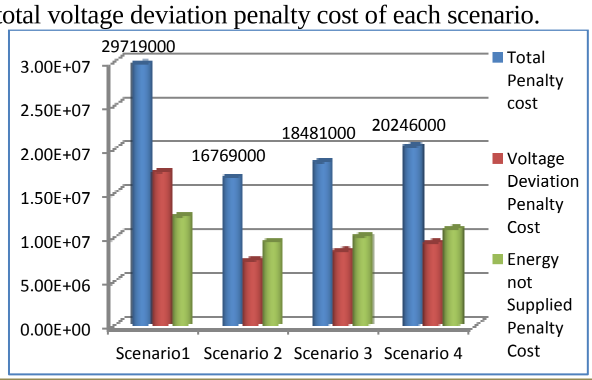

Fig.17. Penalty Costs imposed to the DISCO in a year

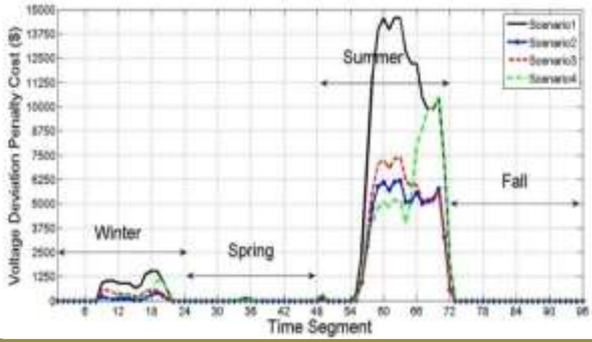

Fig.18. Hourly Voltage Deviation Penalty Cost during a year

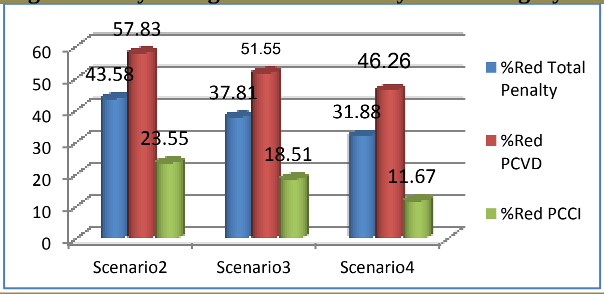

Fig.19. Percentage of yearly reduction in Penalty Costs imposed to the DISCO

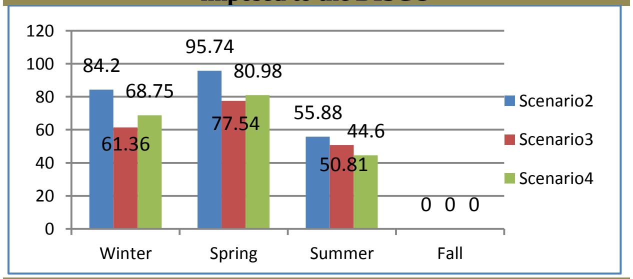

Fig.20. Percentage of seasonal reduction in penalty costs imposed to the DISCO

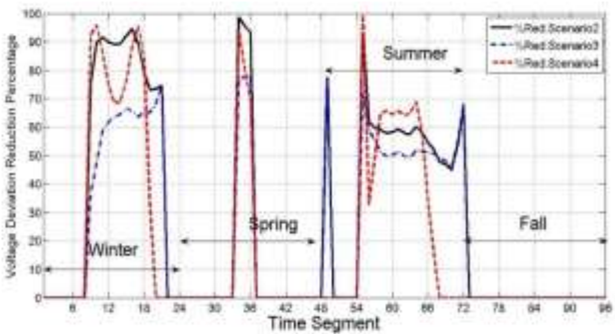

Fig.21. Hourly percentage of voltage deviation reduction during a year

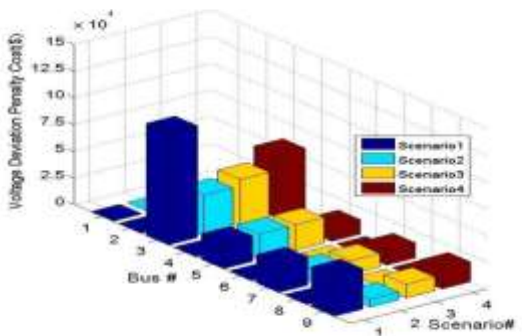

Fig. 22.The amount of Voltage Deviation Penalty Cost corresponding to each bus

4.6. Emission Taxes

As seen in Table5, considering both of the clean technologies resulted into 32.91% reduction in the total emission tax of the distribution system in comparison with the reference case. The planning of the distribution system which uses only wind turbines or solar units causes a reduction of 27.14% and 22.67% in the total emission tax respectively. Figs.23 and 24 show the total amount of emission tax during a year and the seasonal amount of emission tax for all of the scenarios respectively. As seen in these figures, the maximum reduction of emission pollutants occurs using both of the DG units.

4.7. Grant Subsidies

The grant subsidies are paid to the DISCO because of using the clean technologies. The grant subsidy is paid based on the average output power of clean technologies applied in the distribution system. Fig.25 shows the total amount of grant subsidy corresponding to each type of clean technologies in the second scenario.

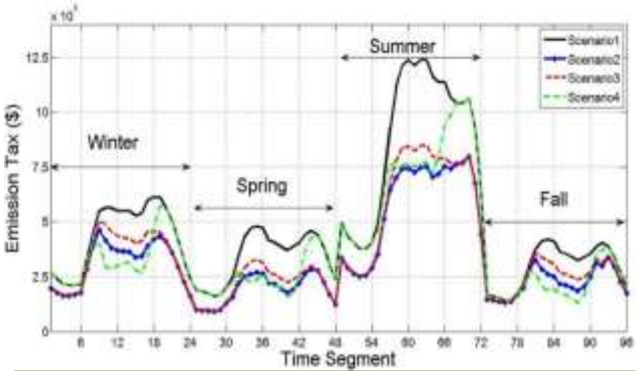

Fig. 23. Hourly Emission Tax of Pollutants during a year

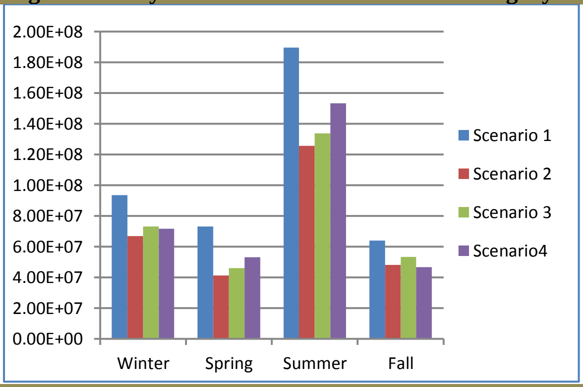

Fig. 24. Seasonal Emission tax for each scenario

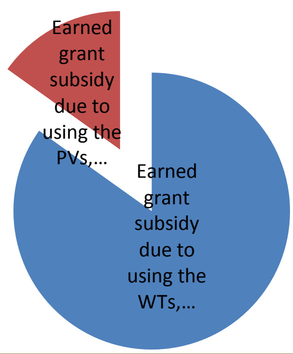

Fig.25. Grant Subsidies paid to DISCO in scenario#2

4.8. Total Costs

The total cost is calculated with the sum of the individual costs minus the grant subsidy. As shown in Table4, the total cost of the DISCO in the base case is 5.5553×10^{8}\$ and it is reduced to 3.8957×10^{8}\$ in the second scenario. In other words, there is a 29.87% reduction in comparison with the base case. The planning the wind turbines and solar units separately, results in 24.72% and 20.48% reduction in the total costs in comparison with the base case respectively. Fig.26 shows the total cost obtained for each scenario (as in Table4).

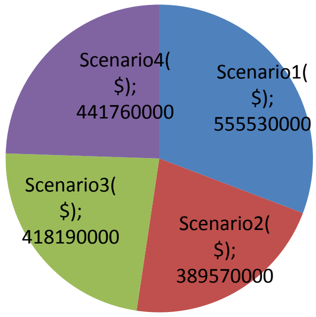

Fig.26. Total Cost of each Scenario

5. Conclusion

In this paper, we have presented a DG planning problem to minimize the total cost of the distribution system considering only clean technologies such as wind turbines and PV modules. Since the clean technologies have an uncertain nature, a new probabilistic way was proposed to solve the DG planning problem. We suggested an hourly DG planning problem based on defining an averaged-day for each season and the historical gathered data of the wind speed and solar radiance. So, the loads are modeled hourly and the wind speed and solar radiance distribution functions. The probability distribution function of the wind speed and solar radiance were defined for each hour using the mean wind speed and solar radiance which was calculated for each hour from the historical gathered data. All of the defined economic, technical and environmental parameters were changed into cost functions. A punishment and encouraging mechanisms beside the other costs were proposed in the planning process.

The DG planning problem was solved with the traditional method and the results were compared with the proposed probabilistic method. In traditional method, the uncertain nature DG units were considered with their average size in the load flow equations. Although the total cost in the traditional method turned out to be lower than the proposed probabilistic method, the results of the probabilistic method were closer to reality as the wind turbines and PV modules have a stochastic nature and cannot produce a constant power during a year. They can generate zero to their rated power due to the wind speed or solar radiance profiles.

The results revealed that using the clean type technologies in the distribution system, in spite of their stochastic nature, leads to a lower costs in comparison with the reference state. However, the best economical scheme is obtained when the wind turbines and PV modules are employed together in the distribution system. We also indicated that all of the hourly, seasonal and total costs were decreased using the clean and stochastic nature units.

Nomenclature

Indices

r	state numbers of M_{PG}
$rtot$	Total number of states of M_{PG}
s	Seasons number(4)
h	Number of time segments(24)
i,j	Bus numbers
ns	Total states (or rows) of probability generation matrix

Constants

$P_d(i)$	Load in bus i(MW)
$price_{loss}$	Energy loss cost (\$/MWh)
$price_{tr}$	Energy purchased from transmission system (\$/MWh)
$price_{uc}$	Upgrading cost (\$/MWh)
$price_{dg}$	Energy purchased from DG units (\$/MWh)
$price_{ENS}$	ENS cost (\$/MWh)
$Y(i,j)$	ijth element of admittance matrix (magnitude)
λ_{ij}	Failure rate of branch between busesi,j (fail/km.year)
SL_{ij}	Capacity limit for branch between buses i,j (MW)
$\theta(i,j)$	ijth element of admittance matrix (angle)
L_{ij}	Length of branch between buses i,j (km)
$fine$	Maximum penalty cost (\$)
$fine_{ENS}$	ENS penalty cost (\$)
Em_{co2}^{conv}	Amount of CO2 emission for conventional generation (kg/MWh)
V_{MPP}	Voltage in MPP (V)
I_{MPP}	Current in MPP (A)
$V_{oc,STC}$	Open circuit voltage in standard test condition (V)
$I_{sc,STC}$	short circuit current in standard test condition (A)
K_v	Open circuit voltage temperature coefficient (v/°c)
T_{Am}	Ambient temperature (°c)
s_r	Irradiance on cell surface or global solar flux (kw/m^2)
T_{nco}	Nominal cell operating temperature(°c)
T_{Air}	Air temperature (°c)
s_n	Standard irradiance (kw/m^2)
K_i	Short circuit current temperature coefficient (A/°c)
$T_{C,STC}$	Cell temperature in standard test condition (°c)
P_{rated}	Rated power (MW)
V_{ci}	Cut in speed (m/s)
V_{co}	Cut out speed (m/s)
V_r	Rated speed (m/s)
$GREnP$	Grant rate of emission not polluted (\$/kg)
Ech_{co2}	Emission tax for kth pollutant
T_{res}	The time is required to be restored the loads after a fault
T_{rep}	The time required to repair the fault and connect any emergency ties

Variables

$P_D^{int}(ij)$	Total load installed in the islanded zone (after failing the branch between bus i,j) (MW)
$CF_{solar}^{h,s}$	Capacity factor of solar unit in hour h season s

$P_{tr}^{h,s}$	Power purchased from transmission system in hour h, season s (MW)
$LL^{h,s}$	Load level in hour h, season s
$PCVD(i)$	Yearly penalty cost because of voltage deviation in bus i ($)
$P_{DG}^{h,s}(ij)$	Total DG capacity installed in the islanded zone (after failing the branch between busesi,j) (MW)
$CET_{r}^{h,s}$	Emission charge (tax) in state g, hour h, season s ($/kg)
LF_{ij}	Average line flow between buses i,j in a year (MW)
$P_{rated}^{solar}(i)$	Rated output power of solar unit in bus i (MW)
$V_{r}^{h,s}(i)$	Voltage in hour h season s for bus i (V)
$\delta_{r}^{h,s}(i)$	Voltage angle in hour h season s for bus i (V)
$P_{loss}^{r,h,s}$	Power loss in state g, hour h, season s (MW)
$LF_{ij}^{s,h}$	Line flow in hour h, season s between buses i,j.
$PCVD_{r}^{h,s}$	Total Penalty cost of voltage deviation in state g, hour h, season s ($)
GS_{solar}	Grant subsidy function because of using solar technology
GS_{wind}	Grant subsidy function because of using wind technology
$P_{rated}^{wind}(i)$	Rated power of wind turbine in bus i (MW)
$P_{av}^{wind}(i)$	Average output power of wind turbine in bus i (MW)
CE_{wind}	Cost of purchased energy from wind turbine ($)
$P_{G1}^{r,h,s}$	Slack bus generation in hour h, season s (MW)
ENS	Energy not supplied
$V_{oc}(s)$	Open circuit voltage in radiance s (V)
$I_{sc}(s)$	Short circuit current in radiance s (A)
T_{Cs}	Cell temperature in radiance s (°C)
$P_{rated}^{wind}(i)$	Rated power of wind turbine in bus i (MW)
$P_{S}(s)$	Output power of PV module (W)

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