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Economic and Technical Analysis of Distributed Generation Connection: A Wind Farm Case Study

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Abstract

This study has been completed for the proposed construction of a wind farm to supply an industrial factory in the north east of the England. The study assessed the potential benefits of changing the operation philosophy of distribution network and embedded generation dealing with factory owner aspects, which are to reduce the electricity bills, reduce the interruption in the network, gain revenue by selling the electricity for the supply company and gain green certificate renewable obligation. The following study presents a comprehensive review of the critical factors and considerations analyzed for installing an embedded generation (Wind Farm) at the factory site. Furthermore, the feasibility study in this report includes factory site description and wind data, design study and wind farm sizing, and economic study.

Keywords: Wind farm; Distribution generation; Generation planning.

1. Introduction

The rapid increases in demand for electricity have created the opportunity for many technological innovations including the employment of Distributed Generation (DG) to achieve a number of benefits. Furthermore, concerns over global climate change and public awareness of the environmental impacts of electrical power generation have created an interest in renewable energy systems for DG[1]. However, Several DGs are much more environmentally

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benign (wind-electricity generations, microturbines, fuel cells, and photovoltaic) than conventional coal, oil, and gas plants[1].

Integrating DGs into Radial Distribution System (RDS) have many positive influences. Those positive impact could be summed as enhancing the system voltage profile; minimizing the network real power losses; deferring transmission and distribution upgrades, and releasing capacity of an existing distribution infrastructure as well as overhead transmission lines paving the road for future expansion[2]. On the other hand, there are some drawbacks such as voltage rise due to the fact that the power is flowing in the both direction which is so called bi-directional power flow, so a significant effort should be taken during the sizing and selecting of the DG capacity and type. However, voltage profile security in the safe limit is our main interest in this study as well as the power losses, overload feeders and interruption. Also, DG has negative impacts on protection systems, voltage regulation, voltage flicker, and short circuit levels[3].

Scott[4], studied the effect of gas turbines on the physical and electrical operation, and also estimated the cost of using this technology in rural areas. Sheng-Yi[5], provided a new DG interconnecting planning technique which includes a coordinated feeder reconfiguration and voltage control in order to calculate the maximum allowable DG capacity at a given node in the distribution network. However, the test scenario is based on wind power generation; the proposed method is also applicable to other types of DG integrations. Barker[6], has described a few of issues that must be considered to ensure that DG will not degrade distribution system power quality, safety, and reliability. The purpose of this paper is to analyze the benefits of employing a wind farm to supply an industrial factory at north east of England. The study presents a comprehensive feasibility study including a factory site description and wind data, design study, wind farm sizing and economic study.

1.1. Site and wind assessment stage

At this stage only an approximate indication of the wind farm output is required in order to confirm the potential of the site. After selecting the site, the next step is to assess the local long-term wind climate by reference to existing data or by long term monitoring. It is necessary to use at least one full year of wind data to take into account variations in wind speed during the seasons. However, an accurate wind speeds measurements and site study is the most critical steps, since wind speeds vary depend on many factors including season, elevation above the see level ,density variation ,pressure and terrain type. Wind Power Class (WPC) is one of the important terms used in planning of wind power plant, which is can be used to determine the suitability of a wind turbine for a specific regime. Wind power density (WPD) indicates the energy at the site that can be converted by the wind turbine. However, the WPC and WPD can be found using the Probability Density Function (PDF) such as Weibull, Rayleigh and Lognormal. They have been used for fitting the measured wind speeds. Further, it was improved that the Weibull distribution method is agreed very well with the experimental data[7]. The probability density function (PDF) of the distribution is given by:

$$f(v,c,\kappa) = \frac{\kappa}{c}\left(\frac{v}{c}\right)^{\kappa-1} e^{-(\frac{v}{c})^{\kappa}} \tag{1}$$

where : v is the wind speed , κ is Shape factor, c is Scale factor

Fig. 1 (a) shows a typical wind speed distribution with average wind speed of 7.63 m/s. This distribution indicates the number of hours per year that a particular wind speed may be expected. The values of c and K are unique specific to the location, the data have been fitted using MATLAB software. The values of the shape and scale factors are determined to be 2 and 8.6104 respectively. Fig. 1 (b) shows both the real data and PDF data which will be used in the following calculations.

In order to get an accurate data from the wind, the tip speed ratio (TSR) and the captured power factor (CPF) of the turbine have to be investigated. The conversion of the wind energy into a mechanical power at the wind turbine can be indicated by CPF[8]. This can be defined by:

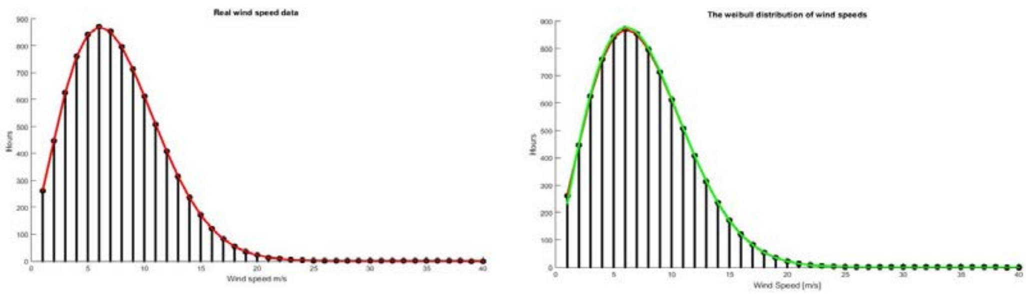

Fig.1 (a) Actual wind data (b) The pdf function of the actual wind data

$$P_{mech} = \frac{1}{2}\rho A V^3 CPF \qquad (2)$$

The CPF value can be determined by the TSR and pitch angle[9]. This can be defined by:

$$CPF = \frac{1}{2}(TSR - 0.022\theta^2 - 5.6)e^{-0.17TSR} \qquad (3)$$

The parameter TSR is the ratio of the circumferential velocity of the blade tips to the wind speed v[8], and is defined by:

$$TSR = \frac{\omega r}{v} \qquad (4)$$

where: ρ is The air density; A is area; θ is Pitch angle; r is the blade length and ω is the turbine angular velocity.

Fig. 2 (a) shows the power captured coefficient as a function of the TSR at different pitch angles (θ=0, 4 and 6). It can be seen that the power coefficient (CPF) is directly proportional to the TSR. The CPF increases as the TSR increases. Further, the output power is directly proportional to the CPF. On the other hand, the Figure shows that the pitch angle plays important role in the power generated. It can be seen that the maximum power coefficient (CPF=0.4176) can be reached at θ=0. This value reduces as the pitch angel increases. A 0.6 MW wind turbine was used for the wind farm. Fig. 2. (b) shows the power speed curve (PV) of the turbine. The annual energy yield is calculated by multiplying the wind turbine power curve with the wind distribution. However, the produced energy for this regime at high of 65m with the average wind speed of 7.63m/s and CPF of 0.4176 throughout the year is 2494.8579 MWh.

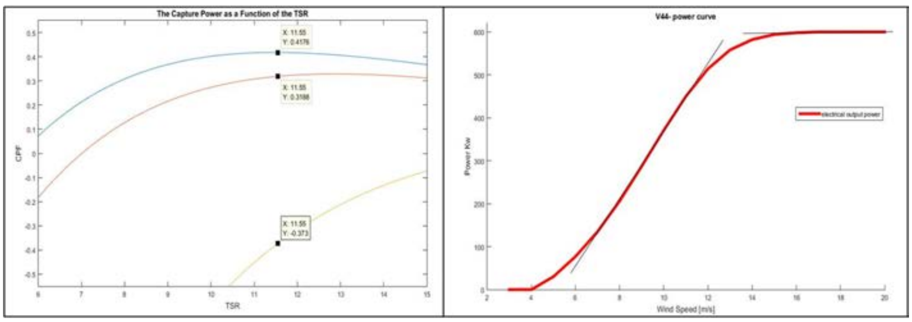

Fig. 2 (a) Relation between the CPF and TSR for specific pitch angle, (b) Wind turbine power curve

1.2. Network Description

Fig. 3 represents the basic features of a distribution system into which an embedded generator, G, is connected. This generator (PG, QG), together with a local load (Village and Factory) at bus 3, and the second feeder is represented by the load connected at bus 5. The third feeder is represented by another load point connected at bus 4. Bus 1 has been chosen as a slack bus. Furthermore, a 33/11 kV transformer with an On Load Tap Changer (OLTC) is connected between bus 1 and bus 2. The voltage at slack bus 1 is assumed to be held constant at its nominal value by the source generation 1.05pu, since the angle voltage of this bus serves as a reference for the angles of all other buses. The tap changer on the transformer between bus 1 and bus 2 maintains the voltage at bus 2 at its nominal value. Overhead lines are typically used for high voltages and cables are employed primarily for medium to low voltage. However, overhead lines are considered in this case. The per unit values of resistances and inductances between buses are 0.4,0.6,0.5 and 0.5 pu for resistances and 0.24,0.36,0.30 and 0.30 pu for inductances between buses 2-3,2-4,2-5 and 5-3 respectively.

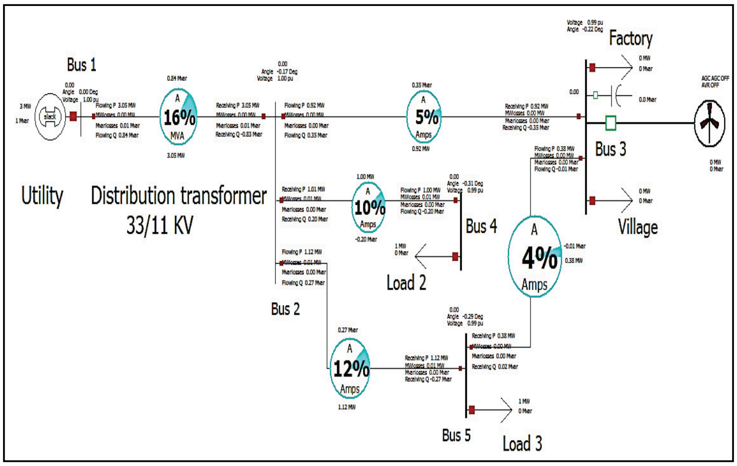

Fig. 3. Distribution system without the embedded generation, the wind farm is off

In order to avoid overestimation or underestimation of the wind farm size, power losses and voltage drop in the network have to be taken in the sizing consideration. It is necessary to calculate the average power on each bus, lines, and transformer in the networks based on the load duration curve for loads, village and factory. Fig. 4 (a) elaborates the maximum and minimum active and reactive power for each load point with the average load. On load tap changer transformer was used to connect the transmission network with the distribution network. To study the loading of the transformer, the duration curve can be calculated to find the average loading on the transformer, as shown in Fig. 4 (b)

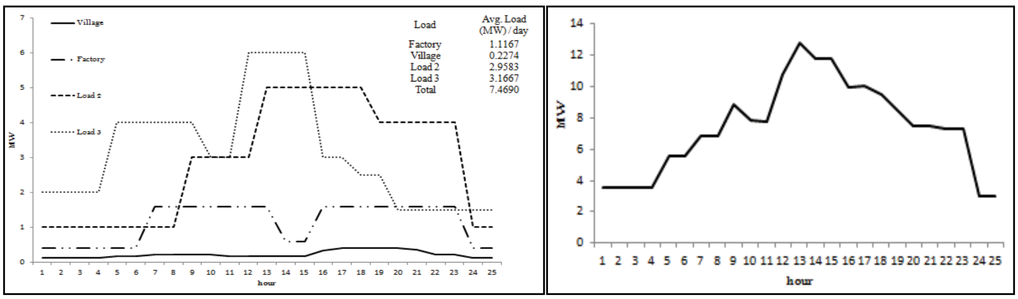

Fig.4. (a) Load duration curve for system load and average power, (b) load duration curve for the transformer

In order to calculate the wind farm capacity. The network power flow, power losses and voltage profile should be determined under normal operation without connection the wind farm at maximum and minimum load. The voltage profile under maximum load is shown in Fig. 5 (a). It can be seen that under normal operation without any embedded generation the voltage drop between bus 1& 2 is about 0.005pu. Further, the voltage drop for the buses 2-3, 2-4, 2-5, and 3-5 are 0.02pu, 0.035pu, 0.028pu and .008pu. Fig. 5 (b) shows the power flow through each branch, the arrow indicate the power flow direction. It can be seen that about 13.5 MW flow from bus 1 to bus 2 which form 71% of the capacity of the branch which is the maximum loading percentage in the network, the minimum value of loading was between bus 3 and bus 5 with about 1.6 MW (16%) of the branch capacity. The power flow between buses 2-3, 2-4 and 2-5 are 3.66 MW, 5.0 MW and 4.54 MW.

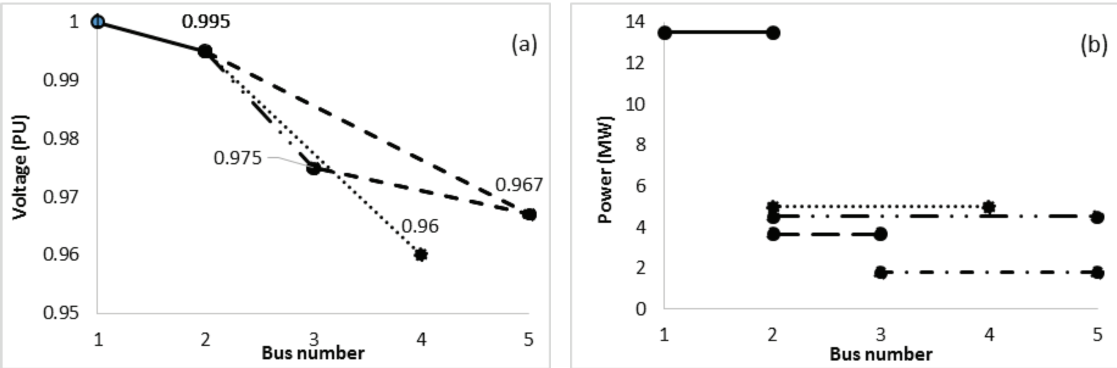

Fig.5 (a) Voltage profile of the system buses, (b) Power losses through the system buses

1.3. Wind Farm and Generation Sizing

The voltage at bus 3 (V_C) in Fig. 3. Can be approximately calculated as follows:

$$V_C - V_B = \Delta V = R(P_G - P_L) + (mQ_C - Q_L)X \tag{5}$$

This simple equation can be used to qualitatively analyse the relationship between voltage at bus 3 and the amount of generation that can be connected to the distribution network, as well as the impact of alternative control actions. The capacity of generation that can be connected to a distribution circuit is determined by analysing the extreme conditions of the coincidence of minimum load (minimum load for village and factory) and maximum generation (PG = PMAX). This policy enables Distribution Network Operates (DNOs) to continue to operate their systems as if generators were not connected at all. The effect of such a connection policy on the amount of generation that can be connected to existing systems can be analysed by the following assumption (0.95 leading power factor operation is assumed). The capacity of the generator that can be accommodated in the existing system is clearly limited by the maximum voltage at bus 3 (1.1pu) and the voltage at Bus 2 (1.05pu).

Under these assumptions, various scenarios were studied. Fig. 6 shows the voltage profile and the losses of 35 MW and 25 MW, respectively. Fig. 7 shows the voltage profile in case of 21 MW wind farm capacity, where the voltage drop between buses 1-2,2-3, 2-4, 2-5, and 3-5 are 0.012pu, 0.0283pu, 0.03463pu ,0.004pu and 0.0323. Furthermore, the losses in the case of 21MW are significantly less than the losses in the case of 35 and 25 M. Thus, the size of the plant generator was determined (PG=21MW & QG=-6.9MVArs).

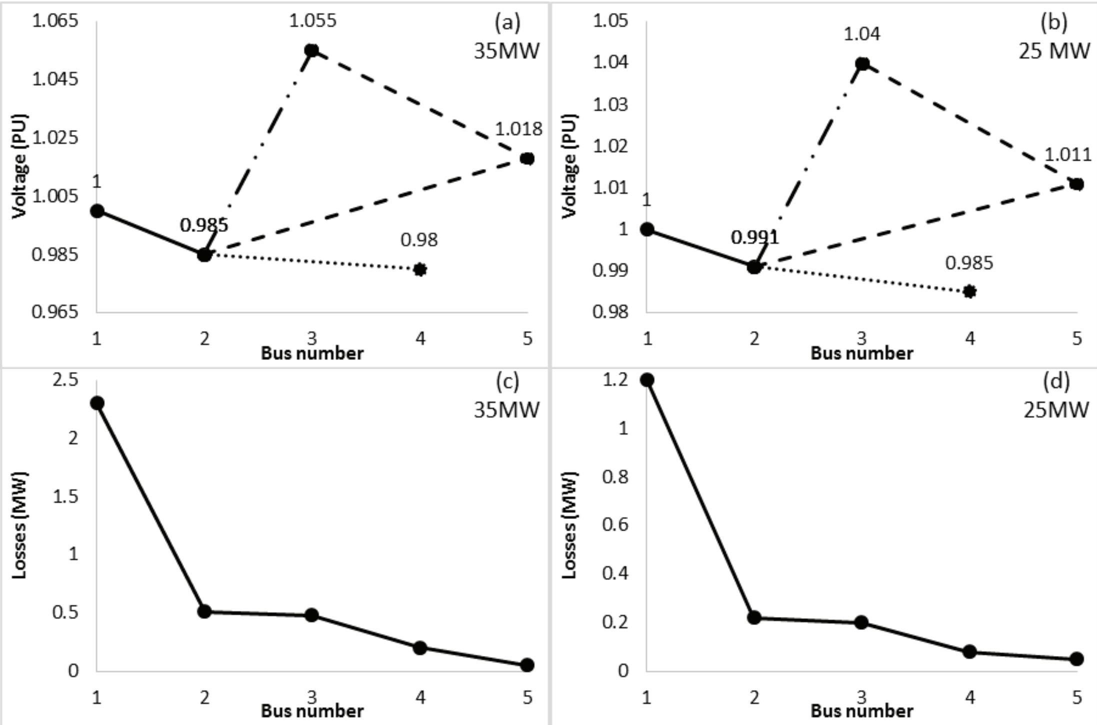

Fig.6 (a) Voltage profile for 35MW, (b) Voltage profile for 25MW, (c) Losses for 35MW, (d) Losses for 25MW a and c for 35MW.

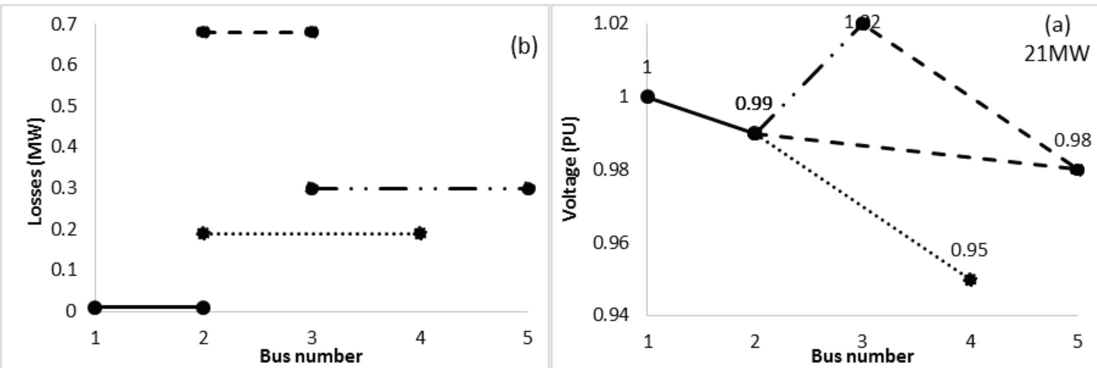

Fig.7 The voltage profile and buses losses of the system in case of 21MW

2. Economics Analysis

2.1. Transformer displacement decision

Bruno[10], argued that due to the significant improvements in the efficiency of modern transformers, there are an economic reasons why older transformer should be decommissioned even when they are still functioning properly. Furthermore, the change in load profile is another reason is lead to replace the transformer. The solution is either install additional transformer to be connected in parallel with the old one in order to spread the load between unequal rating transformer. The second solution is to replace the old transformer with new one with large rating. In term of energy efficiency one large transformer will be more energy efficient than two smaller transformers[10]. Since the voltage profile is also changed, this will lead to a change in the transformer losses so a new transformer is needed to handle the new conditions of the network. Combined all the previous effects from economical point of view the optimal replacement cycle can be determined by calculating Equivalent Annual Cost (EAC) of the transformer and look for the minimum, based on the following equation:

$$EAC = \frac{investment\_\cos t}{AF(i,n)*n} - \frac{residual\_value\_todat}{AF(i,n)*n} + running\_\cos t \tag{6}$$

where: i = annual discount rate , n = number of years in the life cycle of the transformer, AF(i,n) = annuity factor.

To apply the EAC, the existing transformer is 15 years old, so it is necessary to determine whether to keep the old transformer for another 15 years or to replace it with a new one. The calculations results of EAC is summarized in table 1, which shows, it is better to replace the transformer with a new one. The old transformer has an EAC that is almost twice as big as the EAC of the new transformer. According to the EAC, the life-cycle cost of the transformer will be \$30,980.40, and assuming that the transformers life time is about 30 years, the operating cost of this transformer will be \$30,980.40/30 =\$ 1032.7

Table 1. EAC calculation results

	Replacing by a new transformer $/yr	Keeping the old transformer for another 15 years $/year
Annual investment cost	18,147.9$	9,066.7$
Annual rest value	- 817.7$	- 408.8$
No load losses	10,249.2$	20,498.4$
Load losses	31,708.5$	63,416.9$
Maintenance cost	3,400.0$	13,600.0$
Reliability penalty	0.0$	5,972.2$
EAC	30,980.40$	112,146.15$

2.2. Wind farm, factory and village energy consumption

The amount of electricity generated by the wind farm (21MW) is expected to be 87,318 MWh annually, where the rated MW is 21, factory load (MWH/yr) is 6, 827, village load (MWH/yr) is 1,118.2, energy yield for 21MW farm is 87,318 MWH/yr and the farm capacity factor is 47.47 %. Thus the excess energy from the farm after consider a 7 % losses is 80 MWH/yr. The annual energy of the factory is calculated by taking the average consumed power over a year as in Fig.4 (a), which is the average demand for the factory per day is 1.1167 MW/day, with the same approach the annual factory demand and village demand are calculated. The Levelized Cost OF Electricity (LCOE) in electrical energy production can be defined as the present value of the price of the produced electrical energy in cents/kW.hr, also it is the price of electricity required for a project where revenues would equal costs, including making a return on the capital invested equal to the discount rate[11]. It can be defined as the following:

$$LCOE_{wind} = \frac{\sum_{t=0}^{t=n-1} \frac{I_t + O\&M_t - PTC_t - D_t + T_t + R_t}{(1+i)^t}}{C \sum_{t=0}^{t=n-1} \frac{P_t}{(1+i)^t}} \tag{7}$$

where: LCOE: Generation Cost (cents/Kwh), LCOE is Generation Cost (cents/Kwh), I_t is Investment made in year (\$), OMC_t is Operating and maintenance in year (\$), PTC_t is Production Tax Credit (\$), D_t is Depreciation credit (\$) , T_t is Tax levy (\$), R_t is Land rent (\$), P_t is Electrical generation capacity (Kwh) and i is the Discount rate fraction.

Table 2 shows the analysis for Constant cost analysis, Operation costs, and LEOC for 21 MW wind farm capacity, this will be investigated more clearly later in the cash flow analysis and comparing this results with the other scenarios results.

Table 2 Constant cost analysis, Operation costs, and LEOC for MW

Constant costs analysis		*Operation cost and LCOE for MW*	
Capital investment costs ($/kW) Annual Fixed. cost	$1,983.33	Units Generated per Annum(kWh)	83,565,020.98
annual running cost ($/kWhr)	$0.02359	Yearly income (over 10 yrs of project)	$1,253,475.31
Grid connection cost share (%)	12.00%	Gross yearly Income	$15,041,703.78
Construction cost share (%)	10.00%	Insurance	$77,724.92
Other capital cost share (%)	4.00%	Depreciation Credit	$1,295,415.34
O&M Cost share (%)	1.50%	Tax payment per yr	$2,599,887.56
Installation Cost share (%)	30.00%	Net Tax	$1,304,472.22
Insurance share (%)	0.15%	Net income Stream / yr, (first 10 yr)	$14,315,097.95
Annual depreciation Expense	2.50%	Net income Stream / yr, (Rest 15 yr)	$13,061,622.63
Tax Rate	16.00%	Net present value of income stream	$68,802,305.82
Real Rate Of Interest	9.00%	Net real rate of return / yr	4.42%
Price of electricity ($/kWhr)	$0.18	present value of electricity /kWhr (LCOE)	$0.03
Expected life time (yr)	25		
Capacity factor (CF)	47.50%		
Production Tax Credit / kWhr	$0.015		
Discount Rate	8.00%		
Inflation rate	1.00%		

2.3. Simple payback period and Internal Rate of Return (IRR)

This is defined as the length of time required to recover the investment cost from the net cash flow produced by that investment, with no consideration of interest rate, or the number of years required to recover capital cost, ignoring discounting[12]. The LCOE/Kwh for 35, 25 and 21 MW respectively are 0.03369, 0.03342 and 0.03293. Fig. 8 shows the cash flow for 21 MW.

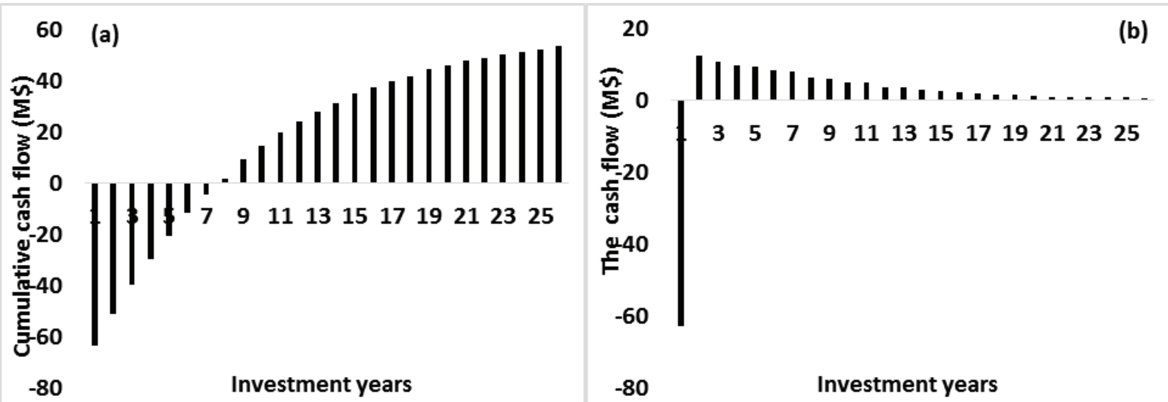

Fig. 8. (a) The cumulative and (b) net cash flow for 21 MW farm with LCOE/Kwh = 0.03293

IRR is the discount rate that equates the two streams of costs and benefits of the project. Alternatively, it is the rate of return 'r' (the value at which NPV=0) that the project is going to generate, provided the stream of costs (Cn) and stream of benefits (Bn) of the project materialises. It is also the rate, r, that would make the NPV of the project equal zero[12], The Internal Rate of Return (IRR) for the project during a 25 year lifespan is about 22%.

$$\sum C_c / \left(1+r\right)^n = \sum B_n / \left(1+r\right)^n \tag{8}$$

where n is the life time of the project.

3. Conclusion

Penetration of DG into the electrical system has an effect on many operation parameter of the electrical system, from which, economics parameters, losses, system capacity and voltage profile. This study represents the investigation of the potential of size of an embedded generator, and elaborates on the economic and technical issues. The amount of the generation connected to the utility bus, is determined using load flow studies based on Newton-Raphson algorithm, usually with the critical case representing conditions of minimum/maximum load and maximum embedded generation output. This operating policy limits considerably the capacity of generation that can be connected to the existing distribution network. The ability of the network to accommodate, and the maximum amount of wind generation that can be connected to the network is determined. Both minimum and maximum loading conditions are considered. By performing a number of load flow calculations using PowerWorld simulator demo version, it can be concluded that the power capacity of the wind farm is 21 MW and absorbs -6.9 Mvar. Economically, the capital cost is calculated to be $1,983.33$ per KW. For our case, A NPV of the income stream is nearly $68,802,305.82 and the IRR for the project during a 25 year lifespan is about 22%, with annual positive cash flows occurring 8 years after development.

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