Wind Power Integration and Challenges in Low Wind Zones. A Study Case: Albania

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Abstract: - High wind performance systems are influenced by many factors such as site wind resources and configuration, technical wind turbine features and many financial conditions. Scenario planning and modelling activities often focus on restricted parameters and numbers to justify wind power plant performance. To better understand possible pathways to scaling up the distributed wind market in Albania, a deep and multidimensional calculations based on Monte Carlo analysis, using RETScreen and wind JEDI model, to assess socio-economic impact as a function of turbine output power, operating and maintenance cost and many other financial inputs by testing different WT (i.e., VESTAS, GAMESA, W2E and NORDEX) with rated power from 3.45 MW up to 4.5MW applied on LCOE, NPV, SPP, equity payback, B-C, after-tax IRR on equity and effects of GHG credits extended at a sensitivity range of ±35% is scientifically performed. From the simulation results LCOE reaches a minimal value of €43.48/MWh, if the debt rate is 99 % and a debt interest rate of 5.0%, a TotCapEx of €828/MW (-35 % less expenditures) indexed as the best scenario. For the base case scenario LCOE results €62.79/MWh, when applying a debt rate of 80% and a TotCapEx of (€1274/MW), while in the worst-case scenario LCOE impart a maximal value of €87.63/MWh if a TotCapEx of €1720/MW (+35 % more expenditures) and a share of 52 % debt rate is applied. Local annual economic impact (m€) during construction period and operating period evaluated in the wind JEDI model result around m€ 89.92 and m€ 23.54, respectively. As a conclusion, wind power plants (WPP), installed in low wind zones (Albania and many other EU countries) would be of interest if an electricity export rate of 110€/MWh, and a GHG credit rate of €50/tCO_2 were accepted.

Key–Words: - Wind power, LCOE, Energy Modelling and Sustainability, NPV, SPP, equity payback, B-C, after-tax IRR on equity and GHG credit rate.

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1 Introduction

The pressure exerted on environmental protection issues due to GHG released from existing energy systems is calling the exigency for immediate global actions. The initiator treaty's UNFCCC countries accepted the fact that uncontrollable increase in energy demand influenced by economic growth and many other factors such as social factors and low-efficiency processes of various branches of the economy are the main reason for negative environmental concerns that brought countries into collaboration under the Paris Agreement in 2015. The focus of the (COP) was to design uncompromising GHG emission policies to reduce the negative effects of global warming and to keep the temperature below 2°C, even to limit the temperature increase to 1.5°C compared to pre-industrial times, [1], [2]. On the other hand, technological progress, [3] and large penetration of different RES for smart, flexible, and diversified energy systems should be supported by wind technologies. The Ukrainian crisis brought a lot of trajectories in the way different countries are supporting the progress of RES exploitations including, incentives, and financing mechanisms toward a competitive and affordable power sector, [4]. On the other hand, renewable power generation technologies, charting the falling costs of the energy transition beyond most commentators' expectations, [5] supporting the future energy transition through revised renewable energy directive EU/2023/2413 which aims the binding renewable target for the EU in 2030 to a minimum of 42.5%, [6]. Increases in the prices of imported oil, higher electricity import rates, and prices influenced by weather conditions have compelled various countries globally to pursue low-cost and clean energy sources. The total final energy consumption (TFEC) in Albania is estimated at 24 TWh, [7], while electricity covers 7.5 TWh, equal to 25% of the total energy demand, fully generated from domestic hydropower plants (HPP), [8], [9]. In the case of the Albanian power sector, an averagely (60-65) % of the country's electricity demand is provided by domestic HPP, and the rest is imported from the regional energy market (250.66 ktoe) usually with higher prices. The Albanian energy roadmap toward 2030 goals aims to reach a RES share of 54.9% of the total final energy consumption in the country, reducing energy consumption and CO2 levels by 8.4% and 18.7%, respectively. The goals can be met by applying different energy efficiency measures (EEM) and large-scale integration of RES coupled with ESS, especially in the T&D section, [10]. Such policies that seek to foster wind power plants must consider local interests such as socio-economic aspects, especially when installed near rural and remote zones. The total capacity of all wind turbines installed around the globe by the end of 2018 amounted to 597 GW, with a potential of 50,1 GW added in 2018, [5]. The focus of this research work is to provide a systematic framework for the techno-economic and socio-economic dimensions, giving a clear response to policy debate when comparing different supportive schemes that promote wind power exploitations in Albania.

2 Wind Speed Prediction and Forecasting

Wind turbines (WT) belong to machines that convert kinetic energy (KE) of air in motion that hits the blades of the rotor into mechanical energy (rotational energy) which is transferred by a co-axial shaft to the generator producing electrical energy categorized as a secondary, transportable, and tradable energy form. The most striking problem of the wind resource is its variability in time (temporally) and geographically even more in space. On a large scale, spatial variability and fluctuations evoke the fact that there are many different climatic regions worldwide, which are identified as windier due to latitude, which affects the amount of insolation.

At a given location, temporal variability on a large scale means that the amount of wind may vary from one year to the next, with even larger scale variations over periods (decades or more), accentuating the fact that energy from wind will be imperishable or not, [6]. On time scales shorter than a year, seasonal variations are much more predictable, but still not with a very high accuracy if a few days ahead information is required. Short-term forecasts necessarily rely on statistical techniques for extrapolating the recent past, whereas longer-term forecasts can carry out studies based on meteorological methods. A combination of meteorological and statistical forecast models and in-site surveys can carry out very useful information on future wind farm projects, [11].

2.1 Wind Power

Nowadays utility-scale wind turbines use airfoils like an aircraft wing as shown in Figure 1 to exercise the kinetic energy contained in the wind stream. Two wind-coercing forces act on the airfoil; known as lift and drag forces. The angle of attack (AOA), which represents the angle between the wing's chord line and the relative wind, is the lift-to-drag ratio (often denoted as L/D ratio).

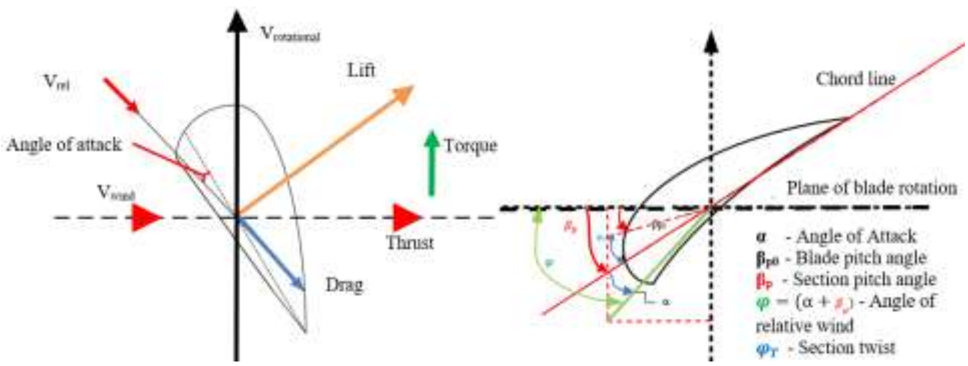

Fig. 1: Cross section of wind turbine blade airfoil (left) and relevant angles (right). Modified after, [12]

AOA is a critical parameter in aerodynamics as it significantly influences the lift and drag forces experienced by an airfoil that defines the overall aerodynamic performance of an aircraft. Turbines depend predominantly on lift force to apply torque to rotor blades which is perpendicular to effective airflow direction. The lift force is primarily responsible for the torque that rotates the rotor and creates mechanical energy, but some torque is caused by the drag force as well. The idea of constructing the tips of the blades, being farthest from the hub, is responsible for a major part of the torque. In the case of pitch-adjusting variable-speed wind turbines, the angle of attack (α) decreases, while the pitch angle (βp_0), increases. In the cases when the wind speed results in less than the rated value, the pitch angle changes its value, normally it is reduced. On the other hand, when wind speed exceeds its projected value, the pitch angle (βp_0) is increased, and therefore, the angle of attack (α) is reduced. The blades will be rotated according to pitch angle value, and the required lift and drag force is applied to the rotor blades by the wind (as given in Figure 1). Other angles of interest in the aerodynamics of the turbine rotor are section pitch angle (βp), angle of relative wind (φ), and section twist angle (φ_T).

2.1.1 Wind Speed Distribution

Wind speed distribution is calculated in the energy tool as a Weibull probability density function, which is commonly used in wind energy due the fact that it agrees well with the observed long-term distribution of mean wind speeds for various sites, [13], [14]. In some cases, the chosen model also uses the Rayleigh wind speed distribution, a specific case of the Weibull distribution where the form factor equals 2. The Weibull probability density function expresses the probability p(x) of having a wind speed x during the year, as given in Equation 1, [15]. The two-parameter Weibull distribution is expressed mathematically as given in Eq.1.

$$p(x) = \left(\frac{k}{A}\right) \cdot \left(\frac{x}{A}\right)^{k-1} e\left[-\left(\frac{x}{A}\right)^{k}\right] \qquad (1)$$

p(x) is the frequency of occurrence of wind speed x, the two Weibull parameters defined in equation (1) are usually referred to as the scale parameter A given in equation (2) and the shape parameter (factor) k, which typically ranges from 1 to 3. A lower shape factor produces higher energy for a given average wind speed. The scale factor (A) is given in Equation 2, [15].

$$A = \frac{\bar{x}}{\Gamma(1 + \frac{1}{k})} \qquad (2)$$

where $\bar{x}$ represents the average wind speed value, and Γ is the gamma function:

The relationship between the wind power density (WPD) and the average wind speed $\bar{v}$ are, Eqs. 3 and 4:

$$WPD = \sum_{x=0}^{25} 0.5 \cdot \rho \cdot (x)^3 p(x) \qquad (3)$$

The average wind speed $\bar{v}$ can be calculated:

$$\bar{v} = \sum_{x=0}^{25} x \cdot p(x) \qquad (4)$$

Where ρ is the air density and $p(x)$ is the probability of having a wind speed of $\boldsymbol{x}$ during the year.

2.2 Wind Energy Curve

The wind turbine power curve, for a wind speed range from up to 25 m/s, generates a set of points given as the energy curve $E_{\bar{v}}$, and can be calculated from expression in Equation 5:

$$E_{\bar{v}} = 8760 \cdot \sum_{x=0}^{25} P_x \cdot p(x) \qquad (5)$$

P_x - Turbine power at speed x and $p(x)$ – represents the Weibull probability density function for wind speed x, calculated for an average wind speed $\bar{v}$.

2.3 Unadjusted Wind Energy Production

The model calculates the unadjusted energy production from the wind equipment for one (proxy) wind turbine at standard conditions of temperature and atmospheric pressure, P_0 and T_0 respectively. Mathematically, the wind speed at hub height is usually much higher than that measured at anemometer height due to the wind shear effect. The following power law in Eq.6 to calculate the average wind speed at hub height, [16], is used:

$$\left(\frac{v_{z(hub)}}{v_{z(aneom)}}\right) = \left(\frac{z_{(hub)}}{z_{(aneom)}}\right)^{\alpha} \qquad (6)$$

$v_{z(hub)}$is the velocity (m/s) measured at the hub height, $v_{z(aneom)}$ is the velocity (m/s) at the anemometer height, $z_{(aneom)}$ represents the geometric height of the anemometer installation and $z_{(hub)}$is the hub height given in (m), and $\boldsymbol{\alpha}$ represents the wind shear exponent.

2.4 Wind Gross Energy Production

Gross energy production represents the total annual energy that can be delivered by the wind turbine before losses in wind speed (free stream), atmospheric pressure, and temperature conditions at the supposed hub height.

$$E_G = E_U \cdot c_H \cdot c_T \quad (7)$$

E_U is the unadjusted energy production, c_H and c_T are the pressure and temperature adjustment coefficients calculated by the following Equation 8:

$$c_H = \frac{P}{P_0} \text{ and } c_T = \frac{T_0}{T} \quad (8)$$

where P is the annual average atmospheric pressure at the site while P_0 and T_0 refer to standard atmospheric pressure and temperature of 101.3 kPa and 228.1K, respectively. The perfect gas law and the stepwise linear temperature variation assumption, the hydrostatic equation yield (Eq. 9):

$$\frac{\partial p}{\partial z} = -\rho z \quad (9)$$

The renewable energy collected is equal to the net amount of energy produced and can be calculated from expression in Eq.10:

$$E_C = E_G \cdot C_L \quad (10)$$

E_G represents the gross energy production, and C_L - loss coefficient and is given by Eq. 11:

$$C_L = (1 - \lambda_a) \cdot (1 - \lambda_{s\&i}) \cdot (1 - \lambda_d) \cdot (1 - \lambda_m) \quad (11)$$

where λ_a ; $\lambda_{s\&i}$; λ_d; λ_m specify array losses, soil and icing losses, downtime, and miscellaneous losses, respectively, are applied to calculate the net energy production. The hour wind plant capacity factor CF represents the ratio of the average power produced by the plant over a year to its rated power capacity, [17], calculated using Eq.12.

$$CF_h = \left(\frac{E_c}{Nameplate\ Power}\right) \quad (12)$$

where E_c is the renewable energy collected, expressed in kWh, CF_h is hourly capacity for each turbine with air density adjusted wind speeds at a given height. Full Load Hours (FLH) for a given WPP can be calculated by using the expression in Eq. 13:

$$FLH = \sum_{h}^{8760} CF_h \quad (13)$$

FLH is a sum of CF for each hour. FLH is a sum of CF for each hour. While FLH is of limited value as a standalone number, it is an important part of the LCOE calculation. FLH is of limited value as a standalone number, it is an important part of the LCOE calculation. According to Betz's Law, no wind turbine can convert more than 59.3% of the kinetic energy of the wind into mechanical energy transformed at the rotor (CF=59.3%), [18].

3 Albanian Wind Potential

In the context of our country, there is a preliminary perception that certain areas such as that Lezha, Korça, the area of Karaburun in Vlora, certain areas in the district of Puka, the area of Kryevidh, part of Rrogozhina municipality, Torovica, and Vau i Dejes part of Shkodra district, etc., have a noticeable flow of wind that can be exploited to produce future electricity demand. A series of international policies are increasingly channeling the Albanian government to diversify more power sources from renewable energy sources (RES), [19], especially exploiting wind potential for electricity generation.

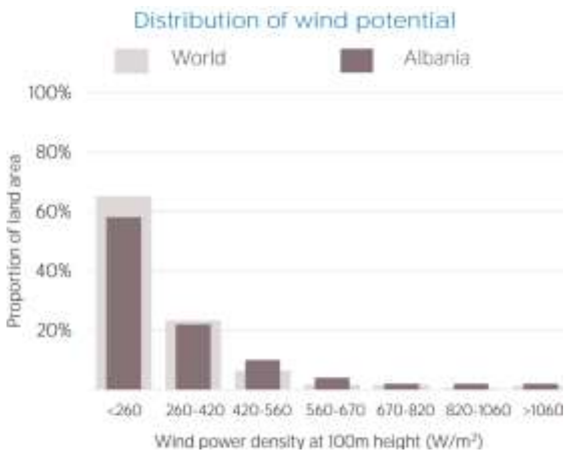

Fig. 2: Distribution of wind potential in Albania as a function of wind power density at 100m height (W/m^2), [20]

Potential wind power density (W/m^2) is shown in the seven classes used by NREL, measured at a height of 100m. The distribution of the country's land area in each of these classes compared to the global distribution of wind resources by wind power density is given in Figure 2. Albanian territory can be a shelter of at least 7500 MW of wind potential.

3.1 Proposed Wind Power Plant

The proposed land-based wind project is situated in the south-eastern part of Albania, near the cross border with Greece, and comprises 40 wind turbines with a rated power of 4.5 MW equating to a capacity of 180 MW and covers an area of 4905 ha part of Korça District.

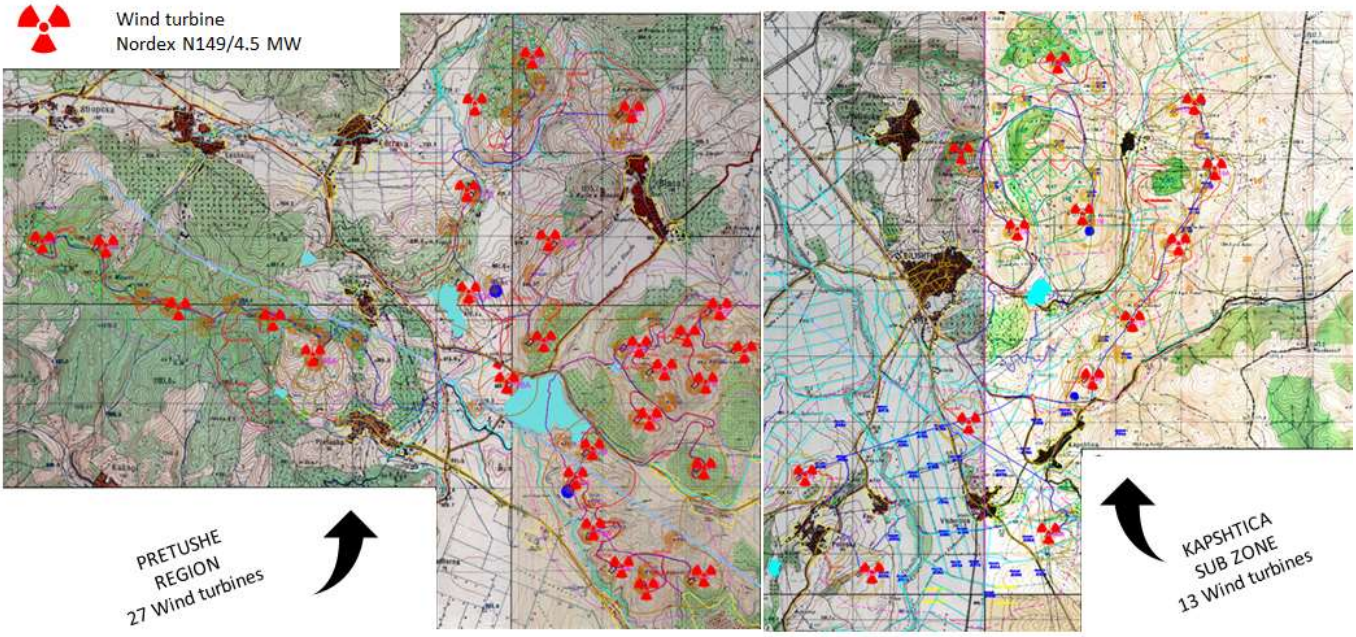

Fig. 3: Distribution of wind turbines on the map for the proposed wind project (Pretusha sub-area and Kapshtica sub-area)

The topographic has identified and provided 40 possible points to settle wind turbines in Pretushe Subzone and in the Kapshtica Subzone as given in Figure 3, respectively. The mast meters installed in the region have provided the wind speed regime and its direction for a period of one year (from February 24. 2008 to February 5.2009), [21]. The highest wind velocity of 6.2 m/s is reached in March, while the lowest value of 3.8 m/s falls in July.

The annual average wind speed chosen for the reference project analysis, which is consistent with prior reports, is 5.8 meters per second (m/s) at 105 meters (m) (hub height). The representative elevation is used to carry out pressure at hub height that impacts AEP (Annual Energy Production).

4 Materials and Methods

In this study, three different nature energy modeling tools are used, as given in the methodology flowchart in Figure 4. The RETScreen energy model, reliable software to estimate power generation, life cycle costs, and mitigation of GHG, [22] and for different RES energy projects is considered the primary tool. A high accuracy level, on the annual electricity generated by the proposed wind power plants (WPP), requires a set of data, including technical features (Wind Turbine type and model, power, and energy curve, and other influencing factors such as climate data, wind mean velocity/or power density at hub height information and wind shear exponent. To re-evaluate the wind speed data, the combination of recordings with automated equipment was analyzed (new wind monitoring technology, providing 10-minute information to average 15-second measurements for both speed and direction). Daily variations of mean wind speed (m/s) are provided by RETScreen Climate Database (CanmetENERGY) which has an integrable Energy Resource Maps (Such as global wind map and the Global Wind Atlas) that do not differ from in site wind values. While the socio-economic assessment of the proposed wind power plant is executed in the wind JEDI energy model.

The validation of the energy production from the proposed wind energy system is performed and executed using an advanced energy modeling tool, EnergyPLAN, which is a deterministic model as opposed to a stochastic model or models using Monte Carlo methods such as RETScreen model, [23]. Both technical and economic context, tower height, rotor diameter rated power and specific yields are evaluated for a set of wind turbines (WT).

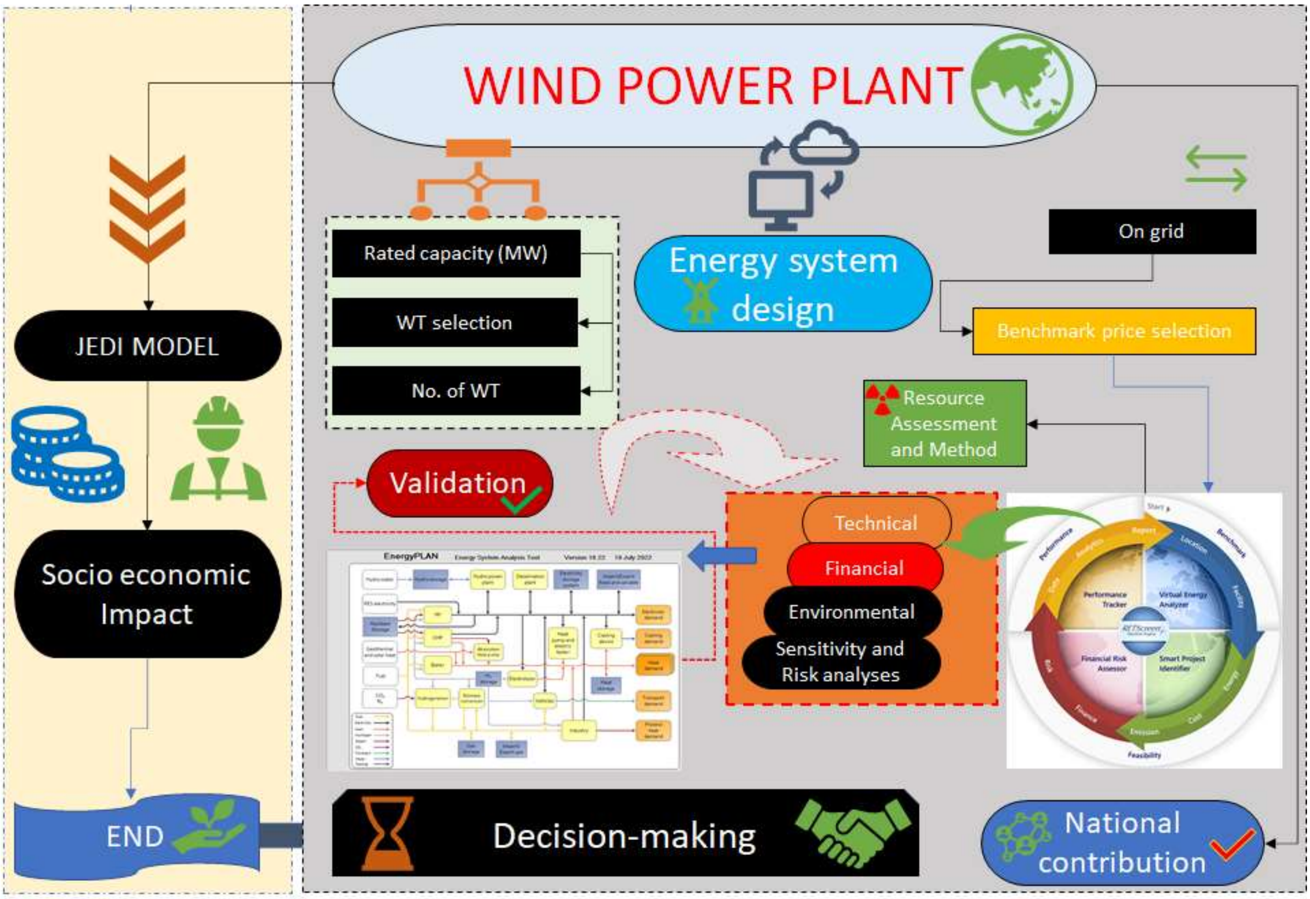

Fig. 4: Methodology flowchart of proposed wind power plant (WPP)

4.1 Tested Wind Turbine Parameters

In In this case study four different wind turbines with specific technical data (Gamesa G128-45 MW, Vestas V126-3.45MW, W2E-151/4.5MW, and Nordex N149/4.5-105m) with rated power from 3.45 up to 4.5 MW are considered. As a first step, the assessment of AEP per each WT assumed to operate in equal conditions is performed (Figure 5). Different types of losses such as array losses (5%), airfoil losses 1%, and miscellaneous losses are accepted 2% due to losses of energy production due to starts and stops, off-yaw operation, high wind, and cut-outs from wind gusts are included in the model. The energy model has included any parasitic power requirements and any transmission line losses assumed for the proposed wind energy project site to the connection point of the selected region, [13], [14] and [21] too.

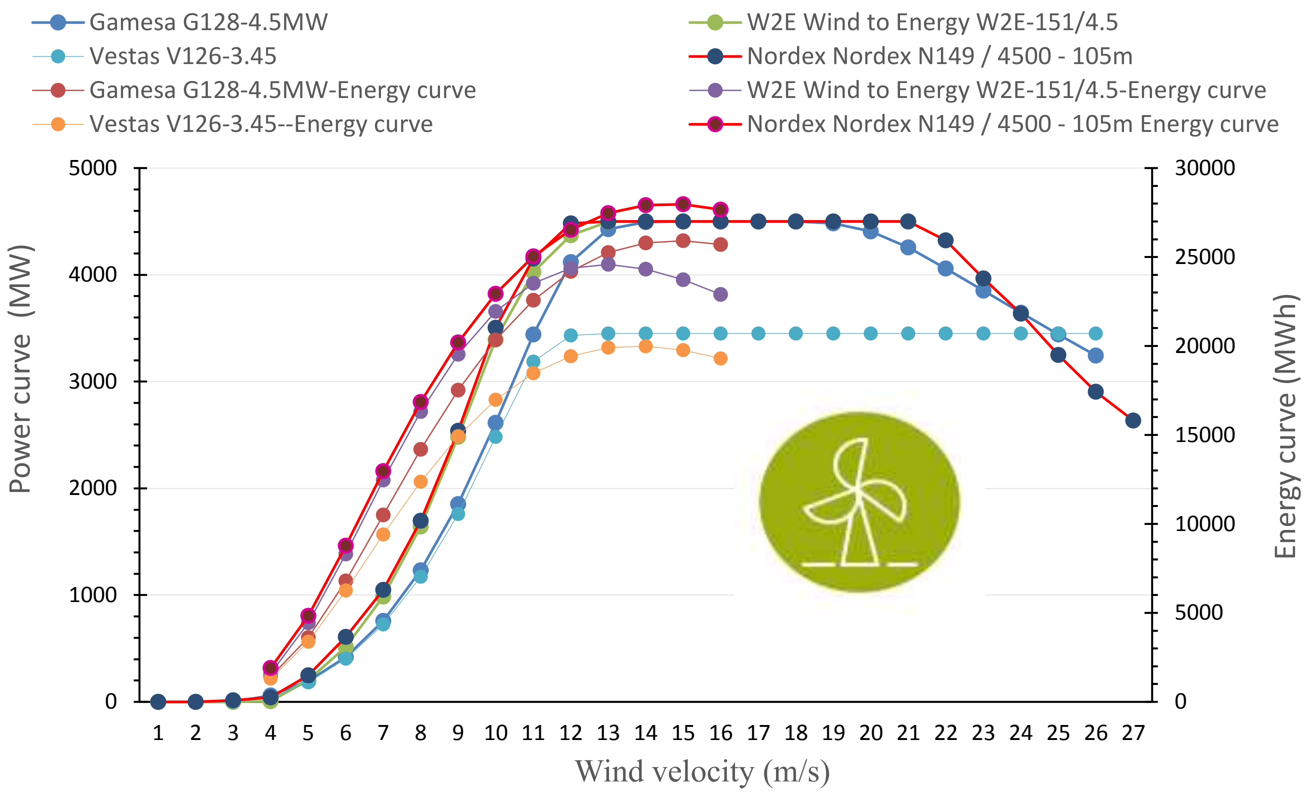

Fig. 5: Power (MW) and energy curve (MWh) delivered by the selected wind turbine measured at a range of wind speeds (m/s), [24]

To subjugate faster and with a high accuracy level, especially at the initial feasibility stage, the latest version of the RETScreen Expert model added the ability to rapidly analyze the feasibility of multiple wind turbines at real site conditions. Based on this strong feature, such evaluation and assessment are performed comparing four different turbine types (i.e., VESTAS, GAMESA, W2E, and NORDEX) with rated power from 3.45 MW to 4.5MW, different tower heights and rotor diameters and results are given in Figure 5. In Figure 5, the power and energy curve delivered by each of the tested wind turbines measured at a range of wind speeds (m/s) is depicted. The power curve for each wind turbine is provided from the model database, and further for the chosen region and real data measurements, the energy curve is depicted as a function of wind velocity. From the simulation results, the selected energy tool calculates the capacity factor (CF) and energy production per year (AEP). This comparison is based on equal simulation conditions.

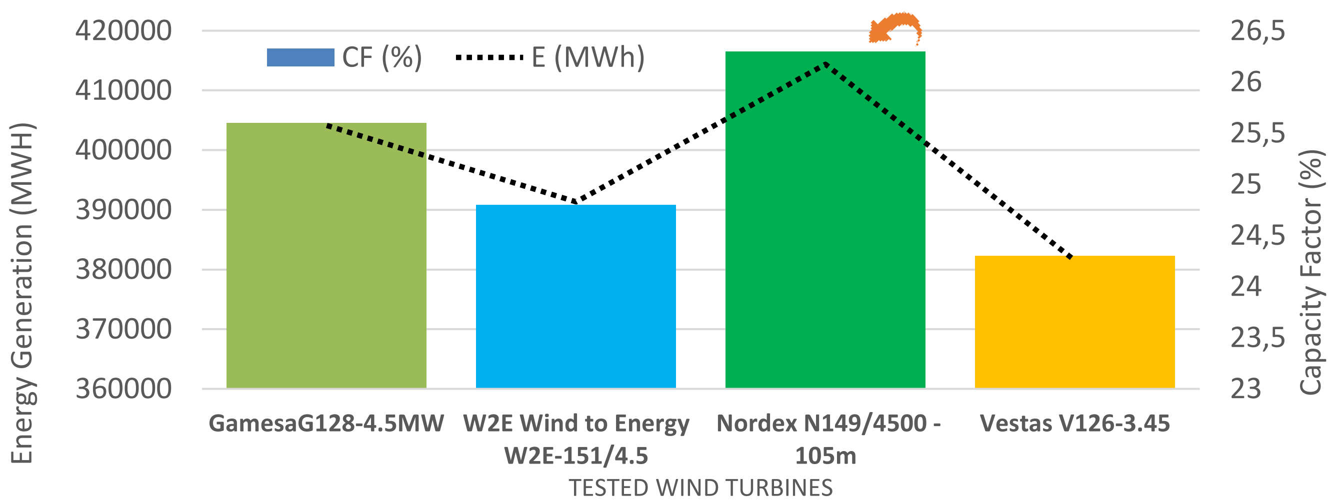

Fig. 6: Result of the Annual Energy Production (AEP) for tested wind turbines

From simulation results given in Figure 6 per each of WT selected, Nordex WT model N149/4.5-105m, performs better and yields a net annual energy production of 414 384 MWh or equivalent to 2,302 MWh/MW/year, which corresponds to a 26.3 % of capacity factor (CF) assuming 98 % of wind turbine availability throughout the year. As a conclusion, based on preliminary simulation results it is reasonable that the extended analyses will be performed based on the Nordex N149/4.5 wind turbine, with a rated power of 4.5 MW and hub height of 105m, as CF and AEP are higher than the other three wind turbines tested.

4.2 Economic Aspects of Wind Power Plants

The capital costs of wind energy projects are dominated by the cost of the wind turbine itself. In Figure 7 cost structure and breakdown for a typical 4.5 MW turbine are given. The average turbine costs vary by brand, model, and other technical indicators. In our analyses, a total investment cost of m€1.274/million/MW, [5], is assumed. The turbine itself shares around 70.4% of the total (WT) cost, while BoS accounts for around 22.1% (such as grid connection electrical infrastructure; assembly installation; site access and staging; foundation; engineering and management development) and the rest finance (contingency, risks etc.) share around 7.5%. Although the cost of wind energy has dropped dramatically in the last 10 years, technology requires a higher initial investment than traditional fossil fuel generators. The investment distribution costs and other costs such as contingencies during construction and other financial parameters that impact the overall efficiency of any wind power plant (WPP) are used based on assumptions.

According to [25], (65-75) % of the cost goes to equipment purchase and the rest to construction costs. In our case study to better assess and map a clear picture of the impact when a set of financial parameters and combinations (inflation rate, fuel escalation rate, discount rate, reinvestment rate, debt ratio, debt interest rate, debt term, equity, and incentives and grants) of the proposed wind power plant (WPP), on the main financial indicators (financial viability) such as Net Present Value (NPV), Simple payback period (SPP), equity payback, benefit to cost ratio (B-C), pre/after-tax IRR-equity or assets, debt service coverage, GHG reduction cost, annual life cycle savings, after-tax modified internal rate of return (MIRR) on equity or assets and electricity production cost (LCOE) several scenarios are designed.

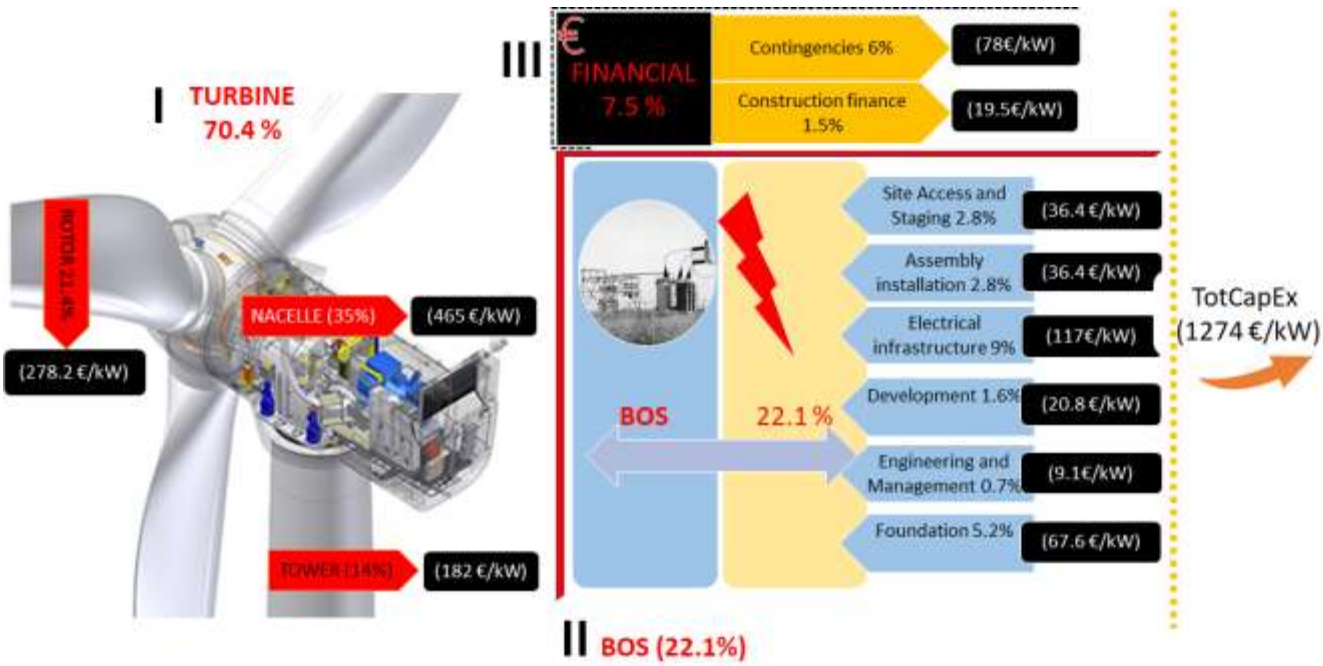

Fig. 7: Cost breakdown (%) for the proposed wind power plant (WPP)

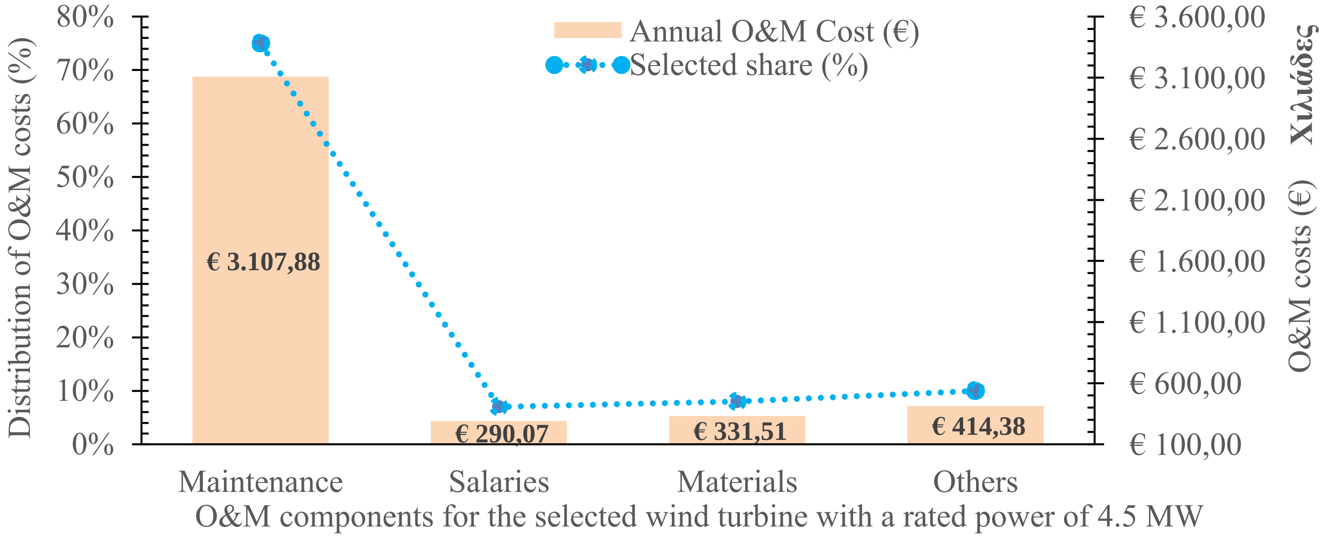

Fig. 8: Breakdown of O&M costs (%) per components for the selected wind turbine with a rated power of 4.5 MW

The operation and maintenance (O&M) costs of Wind Power Plants (WPP) fall between (1.5-1.7) % of the total initial cost, a value which is expected to be spent during the operation phase of the proposed project (such as insurance; regular maintenance; repair; spare parts and administration). In our case study calculations are carried out based on specific costs of electricity generation during a year and assumed (10-15) €/MWh or equivalent to (30-40) €/kW per year, [21].

Maintenance is the largest component of O&M costs, accounting for 75% of the total or €3,107,877 annually, and covers regular servicing to ensure the turbines and critical infrastructure are operating at peak efficiency, as well as any repairs or replacement of parts as required, salaries share 7% of O&M costs, accounting an annual cost of €290,069. Materials are set as 8% of the O&M budget, which is €331,507 per year. The last component refers to "to others" equal to 10% of O&M expenditures (other indirect costs associated with operations), which equates to €414.38 (Figure 8).

All the above results are based on assumptions and techno-economic inputs for the chosen wind turbine as given in Table 1.

Table 1. Technical and economic indicators of the tested wind turbine: Nordex (N149/4.5-105m)

	Selected value	Unit	Information
Turbine capacity	4.5	MW	Onshore Wind Turbine NORDEX
Number of turbines	40	Units	Total installed capacity 180 MW
Capacity factor (CF)	26.3	%	
Swept area		m^2	22,697
Mean velocity value	5.8	m/s	At hub height 105 m
Annual Electricity Production	434800	MWh/yr.	
Electricity export rate	100	€/MW	
Total investment cost	1274	€/kW	[5]
Discount rate	10	%/yr.	5%-8%-10%
Inflation rate	3	%/yr.	
Debt rate	80	%	
Debt interest rate	5	%	
Debt term	15	years	
GHG reduction credit rate	50	€/tCO_2	
Effective income tax rate	15	%	
Depreciation method		Linear	
Depreciation period	15	Years	
Depreciation tax basis	100	%	
Turbine lifetime	20-25	Years	
(O&M)	10	€/MWh	[21]
Land lease	NA	€/yr.	

5 Simulation and Results

5.1 Sensitivity Analyses for the Selected Wind Turbine: NORDEX N149/4.5

The input parameters described in Table 1 reflect the proposed land-based wind project; however, input parameters for a near-term wind energy project are subject to considerable uncertainty. As a result, it is beneficial to investigate how this variability may impact the LCOE and other indicators such as NPV, After-tax IRR, SPP, equity payback, debt coverage service, and other economic indicators. The sensitivity analysis shown in Table 2 focuses on the basic inputs: CapEx, OpEx, and electricity export rate (€/MWh). Sensitivity analyses are executed based on constant assumptions and changing the other set of financial variables. Based on the above analysis of the investment cost and the references of various international agencies such as IRENA. Scenarios are raised on assumptions and supposing a TotCapEx of 1274 €/kW, [5] is assumed in the range of (±35%), exactly from 828 €/kW up to 1,720 €/kW for three different discount rates, 5 %, 8 % and 10 %.

All the indicators are promising and what makes the difference is the investment cost and the discount rate. If an investor has a lower installation price per €828/kW or -35% to reference TotCapEx (€1274/kW), as depicted in Table 2, all economic indicators improve significantly. The sensitivity analysis is carried out considering a change in installation price referring to the base case scenario that assumes a total unit cost of €1274/kW, discount rate of 10%, and sensitivity range of financial parameters (±35) %. In the result given in Table 2 LCOE for the base case (discount rate 10%) results €62.79/MWh, while changing the total unit cost in the range (±35) % then LCOE reaches a minimum and maximum value of €49.97/MWh and €85.21/MWh.

Table 2. Simulation results for sensitivity analyses applied on TotCapEx for three different discount rates, 5 %, 8 %, and 10 %, and impact on after-tax IRR (%); B-C; SPP (yrs.); LCOE (€/MWh) and NPV (€)

AEP ($\frac{MWh}{Yr.}$)								414,384							
Electricity export rate ($€/MWh$)								100							
Discount rate (%)			5					8					10		
TotCapEx ($\frac{€}{kW}$)	1,720	1,497	1274	1,051	828	1,720	1,497	1274	1,051	828	1,720	1,497	1274	1,051	828
After-tax IRR (%)	16.9	23	37.2	16.9	23	16.9	23	37.2	16.9	23	16.9	23	37.2	44.5	64
B-C	3.1	4.1	6.0	7.0	9.6	2.2	2.9	4.4	5.1	7.1	1.7	2.3	3.6	4.3	6.0
Equity payback (yrs.)	6.4	4.3	2.7	2.2	1.5	6.4	4.4	2.7	2.2	1.5	6.4	4.4	2.7	2.2	1.5
LCOE ($\frac{€}{MWh}$)	73.89	65.77	55.29	51.35	43.84	80.78	72.32	59.84	55.40	46.95	85.21	76.15	62.79	58.0	49.97
NPV (€)	**138491125**	**177465006**	**227759101**	**2466800309**	**282742998**	**76736107**	**107884635**	**153839191**	**170181692**	**201330221**	**49766239**	**78346261**	**120511404**	**135506303**	**164086324**

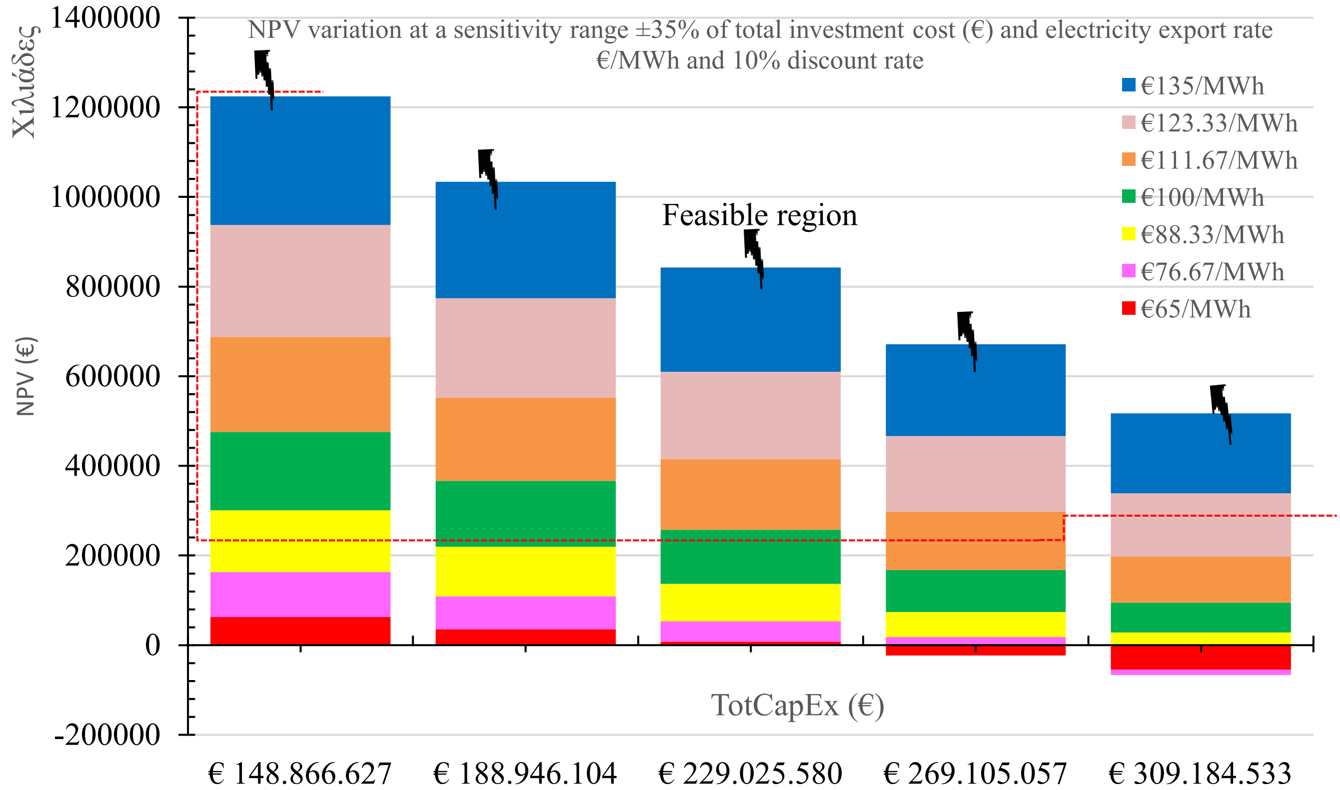

Fig. 9: NPV variation at a sensitivity range ±35% of TotCapEx (€) and electricity export rate €/MWh for a discount rate of 10%

Figure 9 shows the variation in NPV for a 10% discount rate, as a function of the total investment cost (TotCapEx in €) and electricity export rate (€/MWh). The region determined by high NPV values over the black dotted line area is called the feasibility region and is highly impacted by the electricity export rate generated by the wind farm. Also, all NPV values would have a positive increase if applying higher electricity export rates (values in blue bars) and total unit investment cost is reduced by 828€/kW (-35% referring base case scenario 1274€/kW).

NPV calculated for investment cost (+35%) over the reference value of €1,274/kW leading to a total investment cost (€309,184,533), while moving selling price of electricity from minimal value €65/MWh to €76.76/MWh, €88.33/MWh, and €100/MWh the NPV becomes negative € (-23019429) and € (-54467844) if installation price survives an increase or 17.5% and 35% and the electricity export rate €65/MWh. In the case of electricity export rate is reduced by 123.3% reaching a value of €76.76/MWh then NPV becomes negative value of € (-11962501) if installation price experiences an increase of 35%, the point of total capital expenditure reaches a value of 309,194,533€. In all other cases, NPV becomes positive. The feasibility region is depicted in Figure 9. Under these conditions, the sensitivity analysis provides accurate information about the influencing factors in the cost of energy production by the wind power farm. From the analysis, the selling price should be at least above €100/MWh based on the reference scenario applying a total unit cost of €1,274/kW. In the design calculations of the proposed wind farm, the selling price is assumed €100/MWh, and the detailed financial analysis highlights the fact that the plant is not efficient under certain financial conditions, clearly expressing the need for a fixed price agreement. This price must be adjusted respecting the legal framework that supports the production of electricity from wind power plants (WPP), [19] and [26] in Albania.

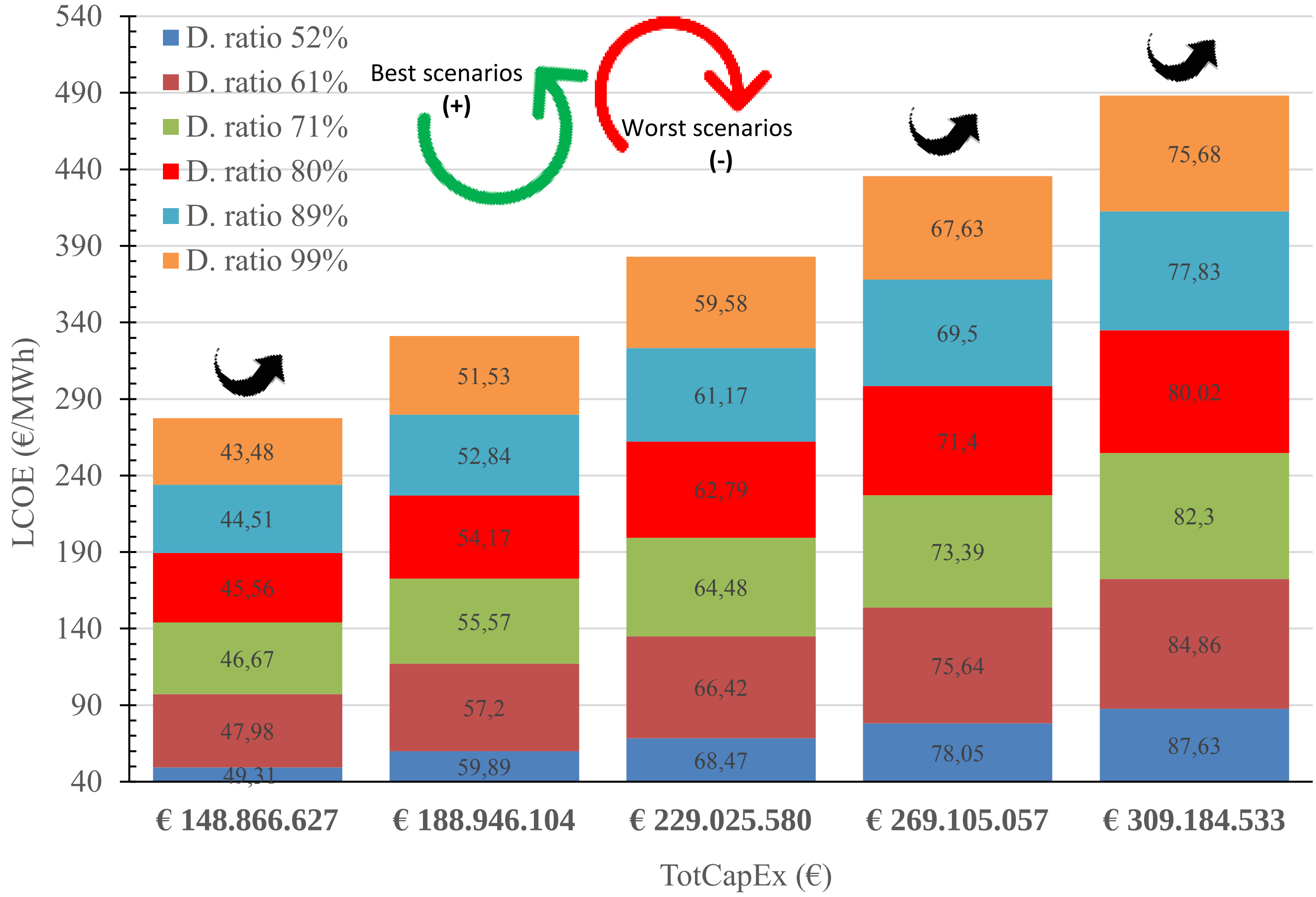

Fig. 10: The variation of LCOE(€/MWh) as a function of total capital expenditures and debt rates (%) at a sensitivity range of ±35% range and electricity export rate €100/MWh

Figure 10 depicts the variation of LCOE(€/MWh) as a function of total capital expenditures and debt rates (%) at a sensitivity range of ±35% range. Changes in LCOE for a set of variables are better than a single variable function and one can be understood by moving to the left or right along a set of specific variables. Values on the y-axis indicate how the LCOE will change as a debt rate and total investment cost (TotCapEx) in the x-axis are altered and all others are assumed constant (i.e., remain reflective of the reference project given in Table 1). The higher the share of debt rate, %), the lower the cost of electricity production, LCOE (€/MWh). From the results of the simulation, it is clearly shown that LCOE varies from 43.48 (€/MWh) in the best case of financial parameters (99% debt rate and assuming -35% less expenditures), 62.79 (€/MWh) referring to the base case scenario (80% debt rate as given in Table 1) up to highest value of LCOE, 87.63 (€/MWh) given the worst-case scenario (52% debt rate and assuming +35% more expenditures). This fact shows that wind power plants (WPP) are highly exposed to risks (financial), leading to the need to determine a more accurate electricity export rate, €/MWh (electricity selling price).

Figure 11, sensitivity analyses of the equity payback as a function of TotCapEx and electricity export rate (€/MWh) at a range of ±35% are given. In our analyses, the equity payback, which represents the length of time that it takes for the owner of a facility to recoup its initial investment (equity) out of the project cash flows generated is calculated. The equity payback considers project cash flows from its inception as well as the leverage (level of debt) of the project, which makes it a better time indicator of the project merits than the simple payback. The model uses the year number and the cumulative after-tax cash flows to calculate this value.

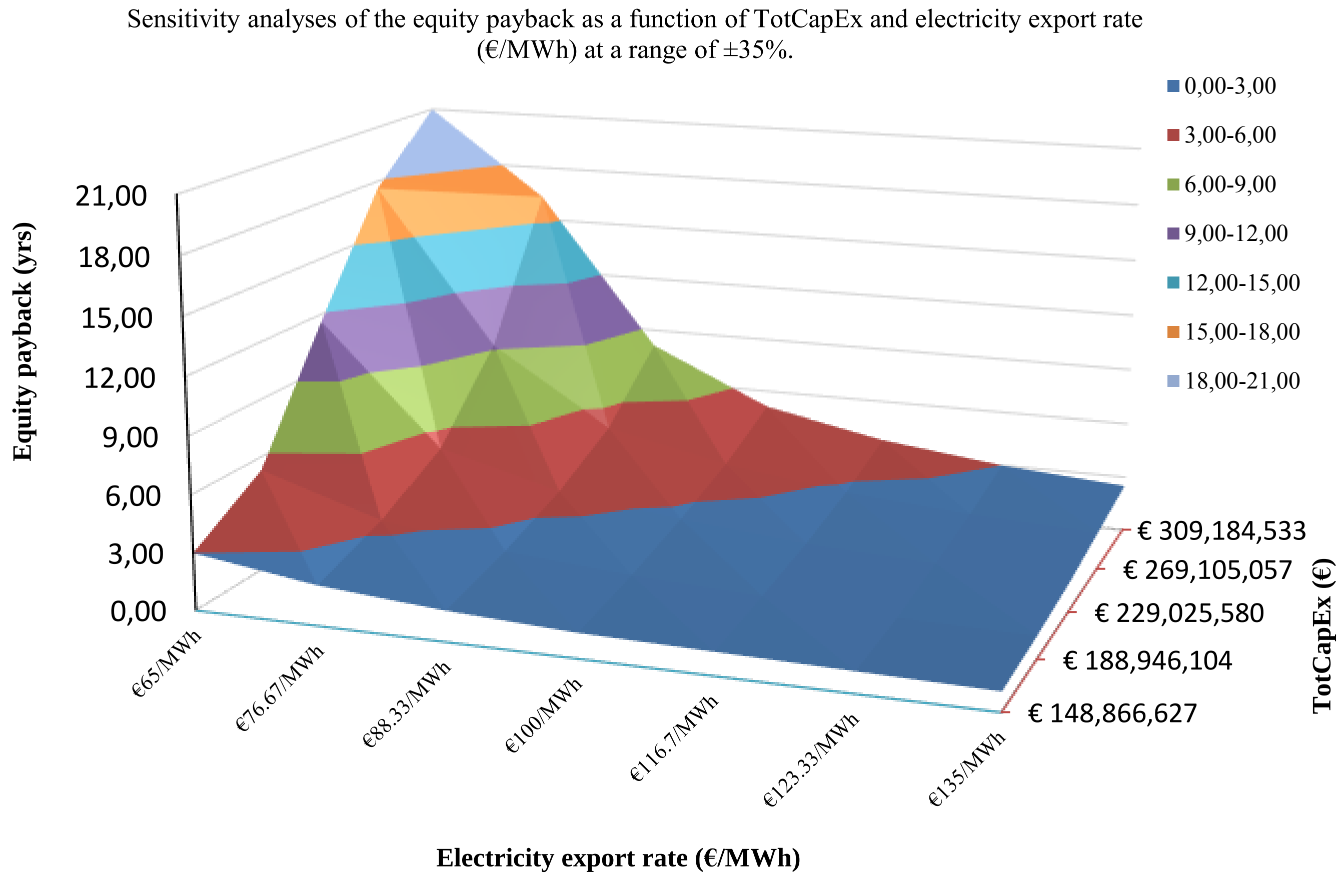

Fig. 11: Sensitivity analyses of the equity payback as a function of TotCapEx and electricity export rate (€/MWh) at a range of ±35%

Referring to results carried out from the simulation and based on the accepted TotCapEx of 1274 €/kW and if the electricity export rate (€/MWh) both varies in the range ±35%, concretely from 65€/MWh to 135€/MWh, then the simple payback period (SPP) would results 10.1 years and decreases to 8.4 years, 7.1 years, 6.2 years and 4.4 years if the electricity export rate is changed within the range €65/MWh, €76.67/MWh €88.33/MWh, €100/MWh, €135/MWh. While equity payback results in 11.6, 5.2, 3.5, 2.7, 2.1, 1.8, and 1.5 years, respectively (in the base case scenario, debt rate 80%, total unit cost 1274€/kW, debt interest 5% and inflation rate 3%). If the electricity export rate (recommended price by the Albanian government) [19] of €76/MWh is assumed, then a simple payback period (SPP) of 8.4 years and an equity payback of 5.3 years is achieved. These numbers clearly show that the wind power plant (WPP) with a capacity of 180MW would be of interest if the electricity export rate would be at least 110€/MWh (refer to other financial indicators below)

The model calculates the after-tax internal rate of return (IRR) on equity (%), which represents the true interest yield provided by the project equity over its life after income tax (Table 1). The after-tax internal rate of return (IRR) on equity (%), is calculated using the after-tax yearly cash flows and the project life, as given in Figure 12.

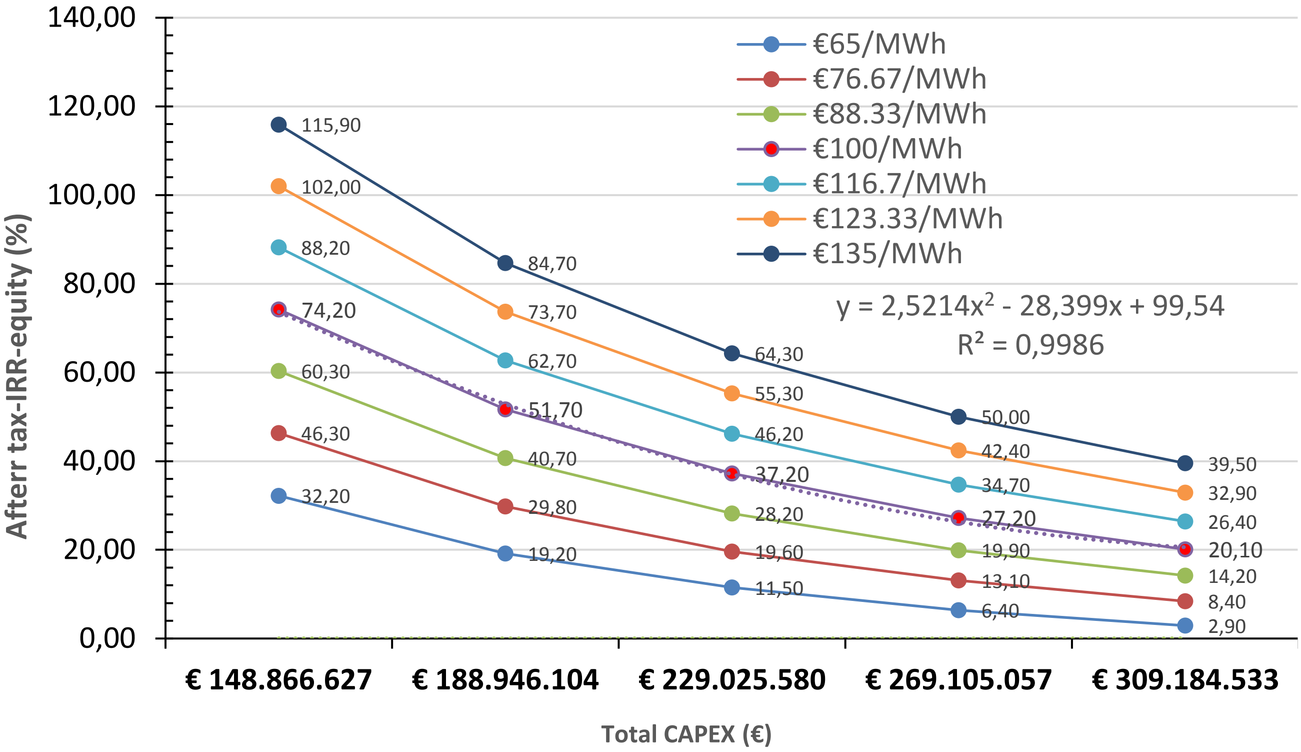

Fig.12: Sensitivity analyses of After-tax-IRR as a function of TotCapEx and electricity export rate (€/MWh) at a range of ±35%

Figure 11 shows the sensitivity analyses of After-tax-IRR as a function of TotCapEx and electricity export rate (€/MWh) at a range of ±35%.

From Figure 12 it is observed that for fixed installation cost (1274 €/kW) as well as selling price of electricity 135€/MWh, 76.67€/MWh and minimum price 65€/MWh after-tax IRR results 64.3%, 19.60% and 11.5%, respectively. The designer has evaluated all the possibilities of the variability of TotCapEx and the selling price of the electricity generated by the plant. This dependence of the IRR was performed for the whole range of the accepted sensitivity analysis. Referring to the electricity export rate of (76.67-100) €/MWh, it is noted that the after-tax IRR on equity has increased from 11.5% to 37.2 %, setting the conditions of a reliable investment from intermittent energy sources such as wind power. Once again, the wind power plant (WPP) would be of interest if the electricity export rate were at least 110€/MWh (refer to other financial indicators such as B-C, equity payback, NPV, etc.)

6 Risk Analyses

A risk analysis, that provides a risk level of 5% by specifying the uncertainty associated with several key input parameters for the is given in Table 3. The evaluation of the impact of this uncertainty can be executed on Net Present Value (NPV), after-tax IRR - equity, equity payback, and levelized cost of energy (LCOE) is performed. The impact of each input parameter on a financial indicator is obtained by applying a standardized multiple linear regression on the financial indicator using a Monte Carlo simulation and several combinations of 2000. The risk analysis empowers to assess if the variability of the financial indicator is admissible, or not, by looking at the distribution of the possible outcomes. The risk analysis for the proposed wind power plant (WPP) is conducted by changing values in the range (±) 35 % of total investment cost (€), O&M (€/MWh), electricity export rate (€/MWh), and the electricity that would be exported to the network, while debt rate (%) and interest of the debt in the estimated time frame is assumed in the range of (±) 25% as given in Table 3.

Table 3. Simulation results for risk analyses using a Monte Carlo simulation and accepted risk level of 5%

Mean	115 814 085
Risk level	5.0
Minimum level of confidence	8622159
Maximum level of confidence	235042617

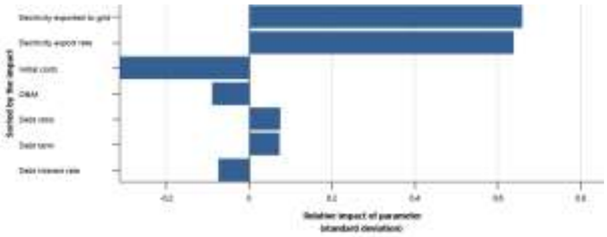

Fig. 13: Impact graph on NPV

Figure 13 shows the impact graph on NPV based on the parameters impacting the economy of wind power plants (WPP). From the Monte Carlo simulation, it is observed that the electricity export rate (€/MWh) and energy exported to the network rate (MWh) have a positive impact (0.64 and 0.66), while initial costs, (O&M) and debt interest rate have a negative impact (-0.31, -0.09 and -0.07), respectively.

The prediction of electricity generation from the proposed wind power plant has a major contribution to the stability of the future economy of wind power plants mainly impacted by weather and the method used to calculate it. The electricity export rate should be carefully addressed based on the above sensitivity analyses.

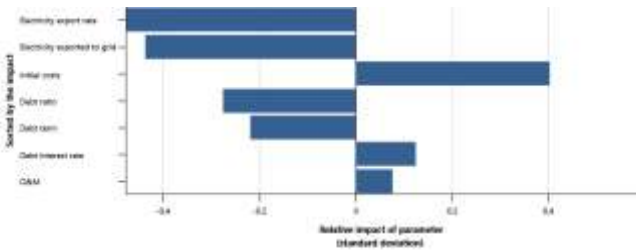

Fig.14: Impact graph on equity payback

Figure 14 shows the impact graph for the equity payback period based on the parameters impacting the economy of wind power plants (WPP). The electricity export rate, energy exported to the grid, debt ratio, and debt term impact negatively the WPP weighting, -0.48, and -0.44, -0.27 and – 0.22, respectively, while initial costs, (O&M) costs, and debt interest rate have a positive impact weighting 0.4, 0.12 and 0.08, respectively.

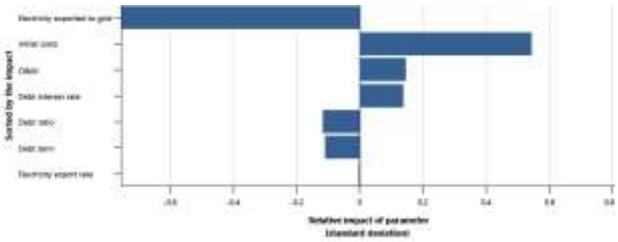

Fig. 15: Impact graph on LCOE

Figure 15 depicts the impact graph on LCOE based on the parameters that drive the economy of the proposed wind power plants (WPP). The electricity exported to the grid, debt ratio, and debt term have a negative impact on the proposed WPP, weighting -0.76, -0.12, and -0.1, respectively, while initial costs, (O&M) costs, debt interest rate, and electricity export rate have a positive impact weighting 0.59, 0.16, 0.16 and 0.008, respectively.

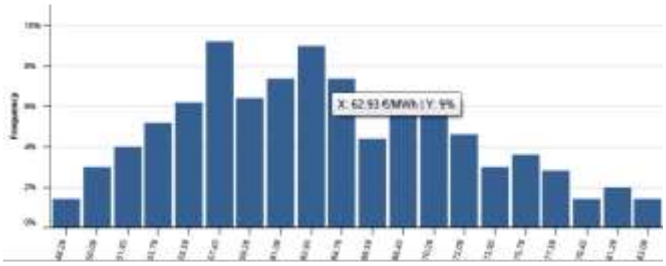

Fig. 16: Distribution of the possible LCOE values in %

The histogram given in Figure 16 provides a distribution of the possible values for the financial indicator (LCOE) resulting from the Monte Carlo simulation. The height of each bar represents the frequency (%) of values that fall in the range defined by the width of each bar, which in most cases (75%) corresponds to values between 53.76 and 76.67 €/MWh. This graph highlights the fact that electricity generation cost (LCOE) is influenced by the financial parameters and electricity exported to the grid, hence we can rapidly assess its variability, supporting again that this price should be at least 110 €/MWh.

7 Cash Flow Analyses

The analysis also shows the annual and cumulative cash flows presented in Figure 17, which were calculated during the lifetime of the wind power plant (WPP). One simple method to evaluate the feasibility of WPP is the simple payback period (SSP) method, which represents the length of time needed from WPP to recoup its own initial cost, out of the revenue or savings it generates during the operation stage.

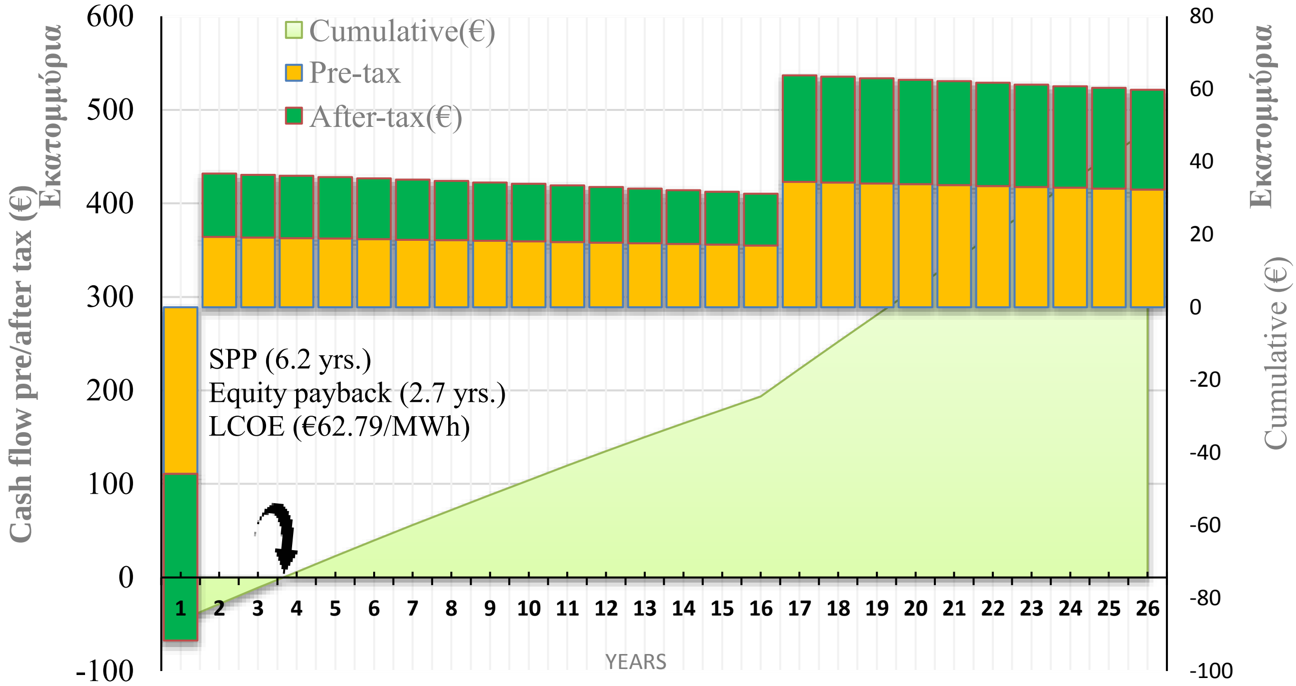

Fig. 17: Cash flow analyses: Simple payback period (SPP), LCOE, and equity payback for the base case scenario (stable parametres given in Table 1)

The simple payback method should not be used as the primary indicator to evaluate a project but can be used as a secondary indicator to assess the level of risk of the investment. Based on based case scenario results (financial parameters as given in Table 1) simple payback results 6.2 years, and equity payback results 2.7 years, which represents the length of time that is needed for the owner of the WPP to recoup its initial investment (equity) out of the project cash flows generated calculated in the year number and the cumulative after-tax cash flows. The equity payback considers project cash flows from its inception as well as the leverage (level of debt) of the proposed wind power plant (WPP) project, which makes it a better time indicator of the project merits than the simple payback method.

8 Emission Analysis

In RES projects, especially wind power plants, all kinds of mitigating policies that lead to a decrease in the cost of electricity production (LCOE) should be considered. However, other analyses are needful to accurately determine the risk and the feasibility region, leading to the determination of the true electricity export rate (€/MWh). Assuming that the amount of electricity produced of 414 384MWh/year from would be produced through the use of simple Rankine cycle burning diesel 2 as fuel (D#2), with an emission factor of 70 kg CO2/GJ, as well as accepting a level of losses in the transmission and distribution network (T&D) of 7%, then the annual CO_2 level for the base case scenario would be 375401tCO2/year. In the case of the proposed WPP, would avoid an amount of 342140tCO_2/year, which is equivalent to 150 008 320 liters of petrol not used 32 110 hectares of forest absorbing CO_2, as shown in Figure 18.

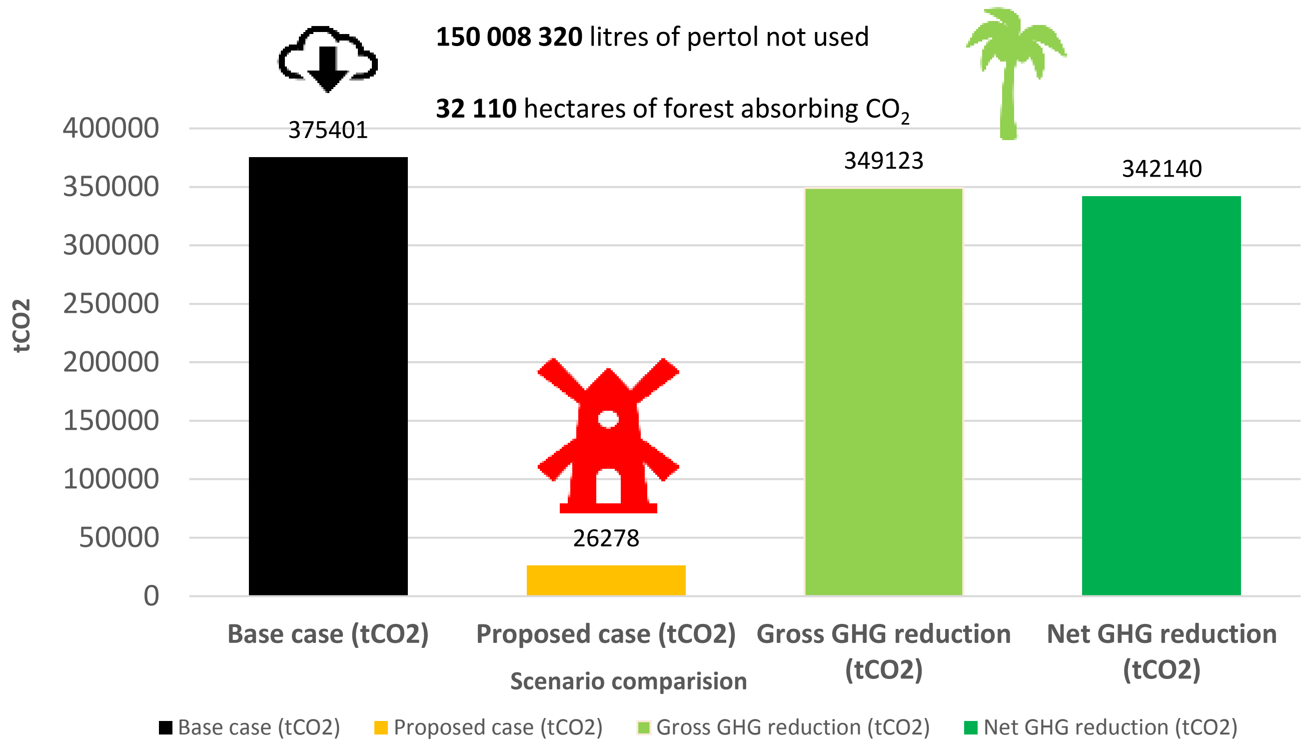

Fig. 18: Emission analysis and differences between base case scenario and proposed energy system (WPP)

8.1 Carbon Shadow Price and GHG Reduction Revenue

The simulation results on the effect coming from the application of carbon credits on the main economic indicators of the proposed wind power plant are given in Table 4. The escalation rate of the "carbon shadow" price was considered (3%), which is the estimated average annual rate of price increase during the life of the energy project, which enables to apply inflation rates to the carbon shadow price value but can be different from general inflation in the cases where carbon prices or other schemes, such as carbon taxes, increase over time. For Clean Development Mechanism (CDM) projects, two options are currently available for the length of the crediting period (i) a fixed crediting period of 10 years or (ii) a renewable crediting period of 7 years that can be renewed twice (for a maximum credit duration of 21 years) as given in Table 4.

The model calculates annual GHG reduction revenue that represents revenue generated from the sale or exchange of GHG reductions. In the model, the percentage of loans that will have to be paid every year as a transaction fee is indicated, which is accepted at the level of 2%. To obtain credits for a GHG project, a portion of the credits must be deducted as a transaction fee, which will be paid annually to the lending agency and/or host country. Benefits from GHG reduction revenues are given in Figure 19, Figure 20, Figure 21 and Figure 22.

Table 4. Simulation results on the effect of carbon credits (€/tCO_2) for a 10% discount rate in the ±35% range of the sensitivity analysis of the total investment cost concerning the fixed cost (€1274/kW)

Carbon shadow price | GHG reduction revenue

GHG reduction credit rate	€/tCO_2	50
GHG reduction credit duration	yr	21
GHG reduction credit escalation rate	%	3%

Gross annual GHG emission reduction	GHG credits transaction fee	Net annual GHG emission reduction	GHG reduction revenue
tCO_2	%	tCO_2	€
349,123	2%	342,140	17,107,014

Carbon offsets

Remaining GHG emission reduction required	tCO_2	26,278.0551	26,278
Net annual GHG emission reduction	tCO_2	375,401	100%
Carbon offsets rate	€/tCO_2	50	
Carbon offsets cost	€	1,313,903	

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From the Figure 19, equity payback is improved by 1.8 times or reduced from 2.7 years to 1.5 years in comparison to the base case scenario.

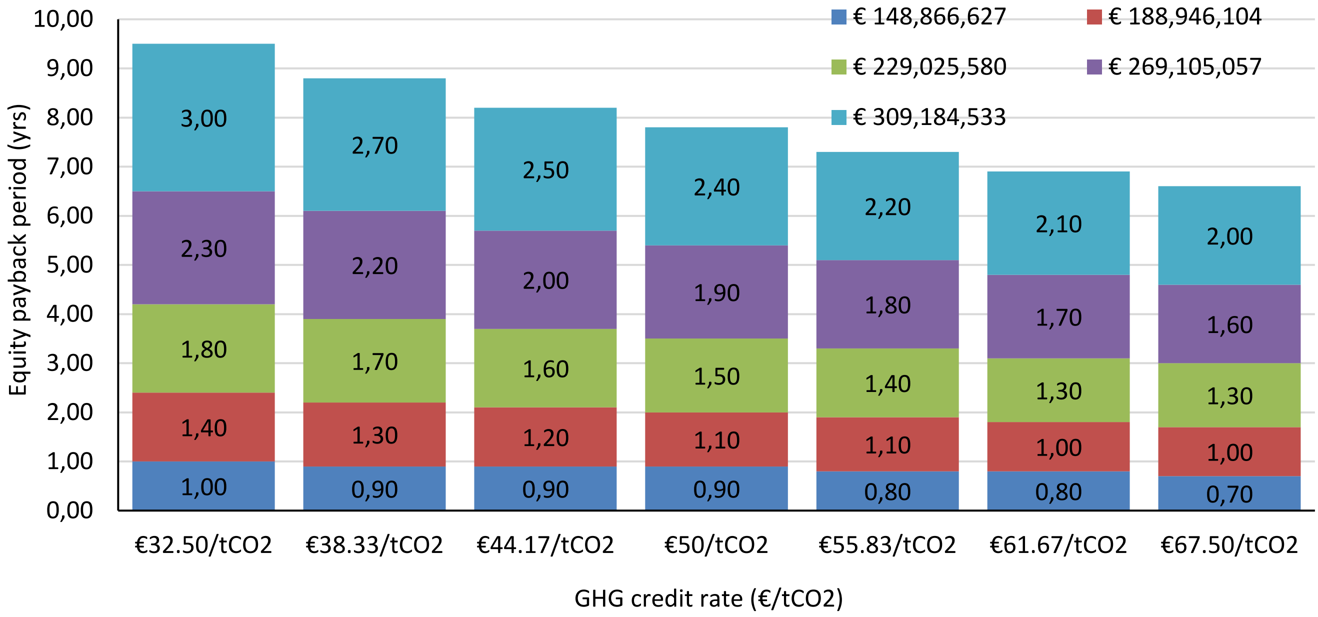

Fig. 19: Effect of carbon credits (€/tCO_2) on equity payback as a function of total investment cost at a sensitivity range of ±35% for fixed other financial parameters

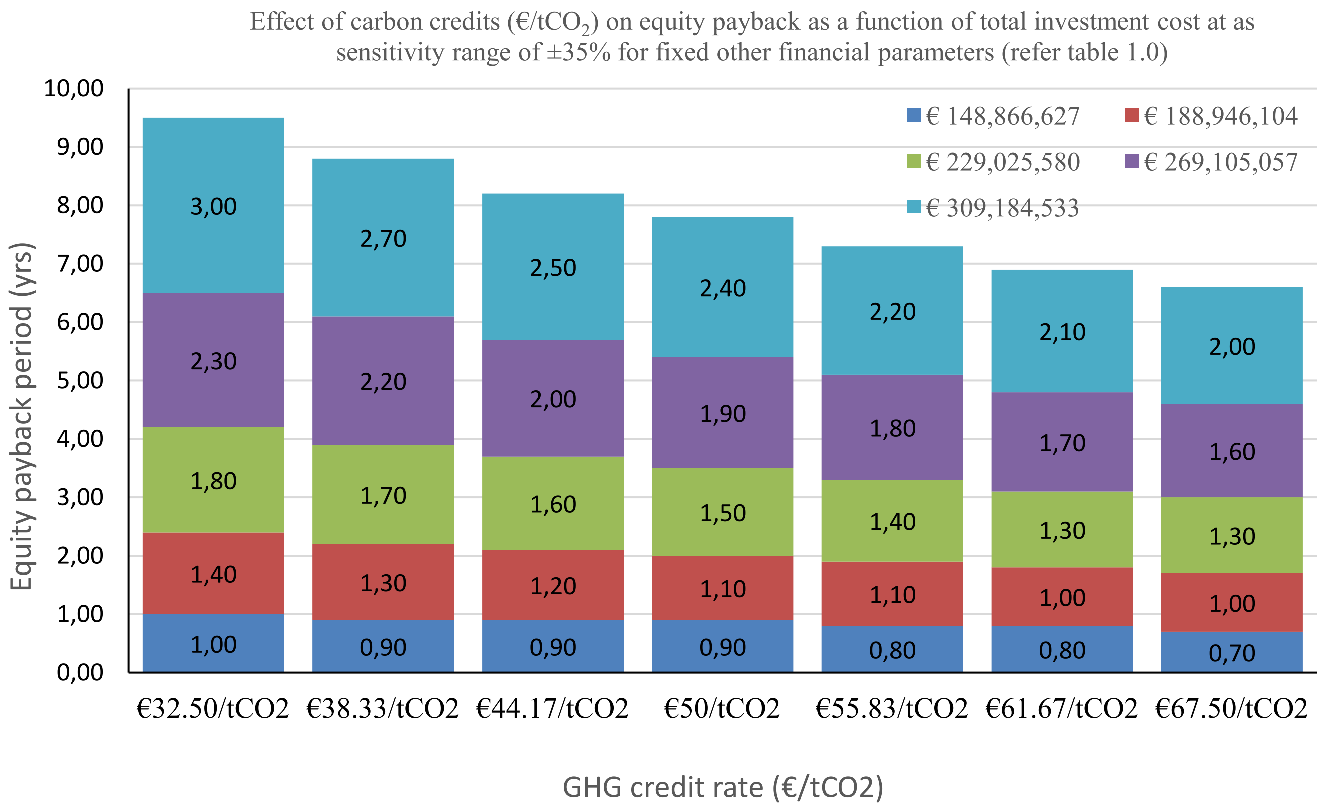

Fig. 20: Effect of carbon credits (€/tCO_2) on equity payback as a function of total investment cost and electricity export rate for a sensitivity range of ±35% (other financial parameters given in Table 1 are kept unchanged)

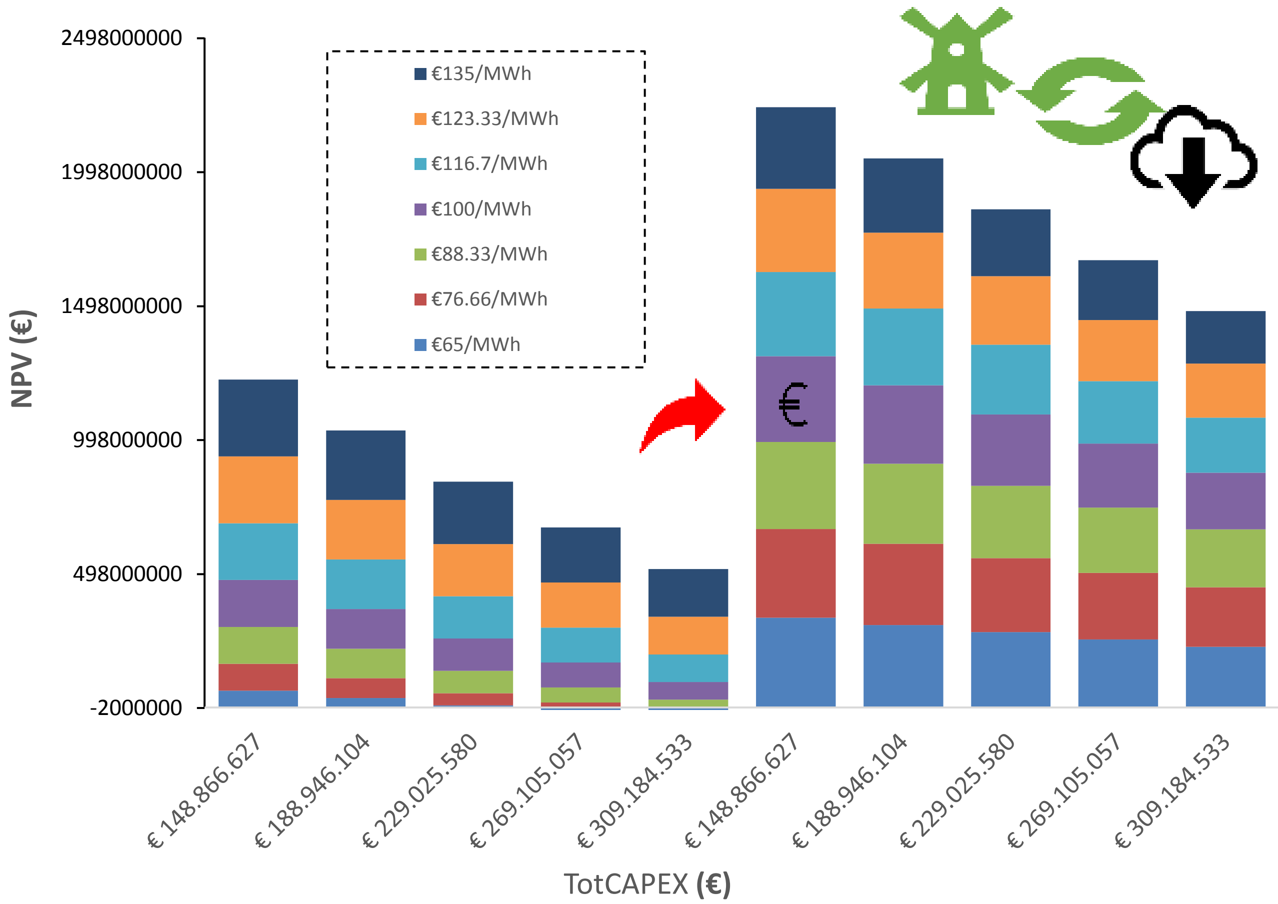

Fig. 21: Effect of carbon credits (€/tCO_2) on NPV as a function of total investment cost and electricity export rate at a sensitivity range of ±35% (other financial parameters given in Table 1 are assumed fixed)

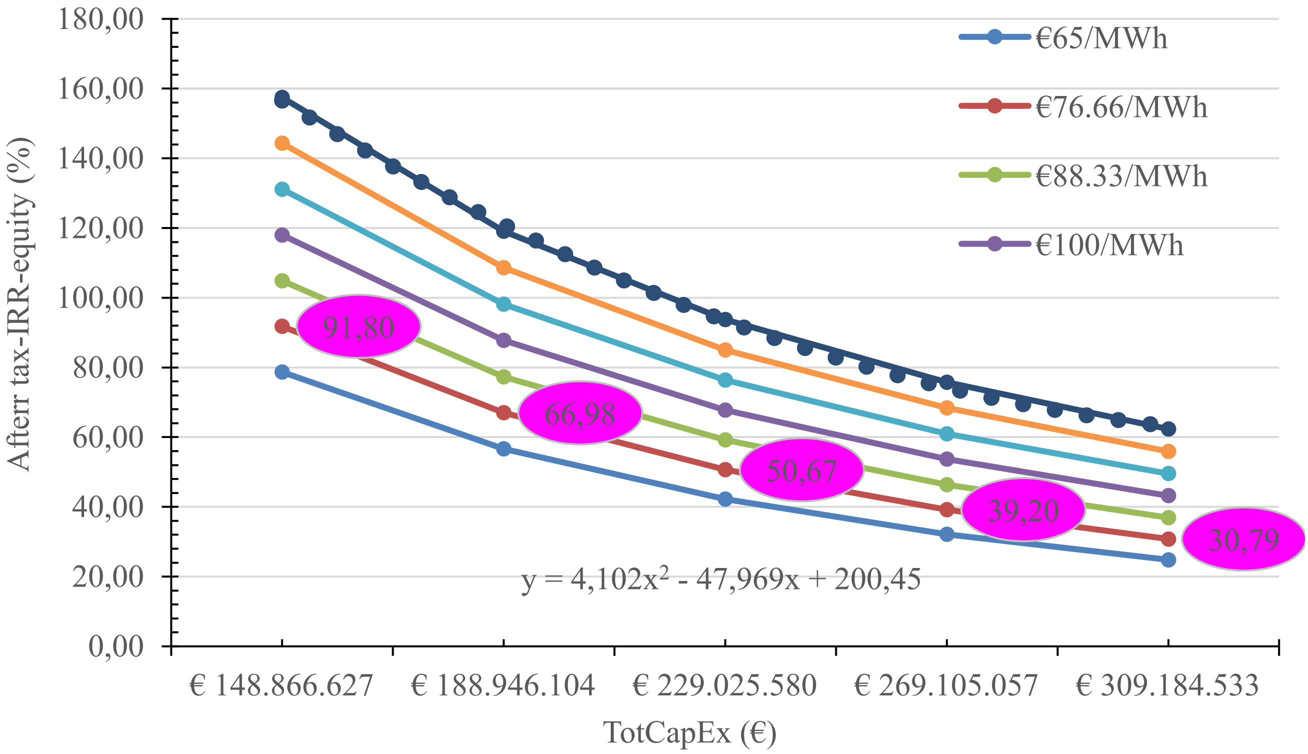

Fig. 22: Effect of carbon credits (€/tCO_2) on after-tax-IRR on equity as a function of total investment cost and electricity export rate at a sensitivity range of ±35% (other financial parameters given in Table 1 are assumed fixed)

As expected, in Figure 20 and Figure 21, the equity period is highly influenced by initial cost, electricity export rate, and GHG credits. If we apply a carbon credit value of (€50/tCO_2) extended to the range of the sensitivity analysis ±35% of the total investment cost and electricity export rate, then the simple payback period (SPP) is decreased from 8.4 years to 5.7 years.

From the simulation results of the proposed wind power plant as given in Figure 19, Figure 20 and Figure 21, it is observed that the impact of the "ETS" emission trading schemes will bring significant benefits to the economy of the wind proposed wind farm project. If a carbon price of €50/tCO_2 is assumed, then the equity payback period will be reduced from 2.7 years to 1.5 years for a fixed electricity export rate of €100/MWh, discount rate 10% and total unit installation cost of (€1274/kW). Other factors that have an impact on the price may include voluntary or required reduction of emissions; private or public purchase of credits; tradable credits (Trading Schemes such as EU ETS), and many other national or regional schemes and technologies they use.

Figure 22 shows the function of "after tax IRR" for different levels of capital investment and electricity export rate extended at a sensitivity range of ±35% (other financial parameters given in Table 1 are assumed unchanged). From Figure 22, it was observed that for the chosen cost of installation (1274 €/kW) as well as electricity export rates of €65/MWh and €135/MWh, after-tax IRR results 11.5% and 64.3%, and if carbon credits rates are applied, this indicator increases to 42.24% and 93.71%, respectively. The analysis showed that "after-tax IRR" increases with the reduction of capital investment (TotCapEx) and with the increase of both electricity export rates and carbon credits.

Referring to the electricity export rate in the range (76-100) €/MWh, it is concluded that the after-tax IRR on equity varies from 50.67 % up to 67.79 %. These values are acceptable and encouraging especially for projects with high financial risk such as energy projects from renewable generation sources (RES) and again leading to the conclusion that the electricity export rate should be adjusted at least to €110/MWh.

9 Socio-economic Impact

The economic impacts of wind energy project development can be significant to both the rural counties and the state in which the project is located. The benefits that are generated by the expenditures, both during the construction and the operations phases of wind plants, depend on the extent to which those expenditures are spent locally, as well as the structure of the local and state economies. The Land-Based Wind Jobs and Economic Development Impact model (LBW JEDI model) is an easy-to-use tool that can be used by county and state decision-makers, public utility commissions, potential project owners, developers, and others interested in analyzing the economic impacts associated with new or existing power plants, fuel production facilities, or other projects. The model provides an approximation of the economic impacts to the local society and the state that can be generated from wind project development, during the construction phase of the project and throughout the 20 to 25-year life, or operating years, of the project, [27]. The wind JEDI model has limitations in the point of view as it does not consider potential electricity price impact or alternative investment. These benefits arising from the proposed wind power plant can be used for future reference wind energy systems in Albania.
Accurate forecasting of renewable energy production is extremely important to ensure that supply meets the demand path as deviations have an impact on the system's stability and could potentially cause a blackout in some situations, [28].

As can be seen from the simulation results in Figure 23(a, b, c, d) the wind JEDI model easily calculates jobs, earnings, and output distributed across three categories including project development and on-site labor impacts, local revenue and supply chain impacts, and induced impacts for the proposed wind power plant of 180 MW capacity. The number of jobs during the construction period and operating period exceeds 32 and 7 on-site jobs respectively, 74 and 17 induced impacts and 111 and 74 local revenue and supply chain impacts, respectively as depicted in Figure 23. Local annual economic impact (m€) during construction period and operating period are m€ 89.92 and m€ 23.54, respectively.

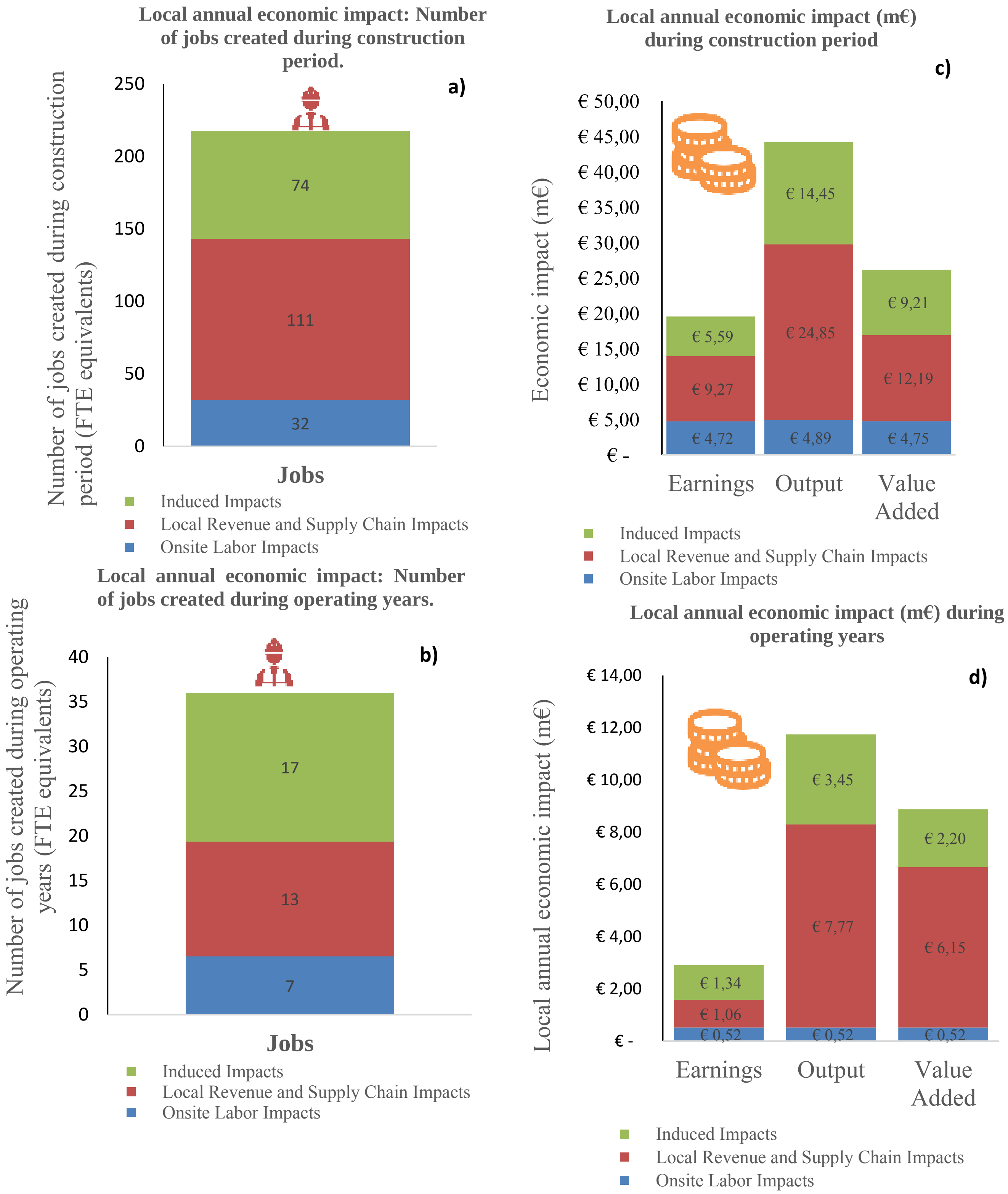

Fig. 23: Socio-economic impact from a 180 MW wind power plant: a) Number of jobs created during the construction period. b) Number of jobs created during operating years. c) Local annual economic impact (m€) during the construction period, and d) Local annual economic impact (m€) during operating years

10 Conclusion

This study presents a snapshot of the levelized cost of energy (LCOE) of a land-based wind power plant with a total capacity of 180 MW, based on real market condition data as given in Table 1, especially for low wind zones such as Albania. To better understand possible pathways to scaling up the distributed wind market in Albania, deep and multidimensional calculations based on Monte Carlo analysis using the RETScreen model and wind JEDI model, to assess socio-economic impact as a function of turbine output power, operating cost, and maintenance cost and other financial conditions are included. From the simulations it is proved that LCOE becomes minimal €43.48/MWh, if the bank provides a debt rate of 99 % and a debt interest rate of 5.0%. In the scenario with €828/MW (-35 % less expenditures) the LCOE results €62.79/MWh considering 80 % debt rate, inflation rate of 3 % up to a maximal LCOE value of €87.63/MWh called as the worst-case scenario (+35 % more expenditures) €1720/MW with a share of 52 % debt rate (Figure 10). Local annual economic impact (m€) during construction period and operating period are evaluated around m€ 89.92 and m€ 23.54, respectively.

In conclusion, the promotion of a wind power plant (WPP), located in Albania can be feasible if the electricity export rate (selling price) is at least 110€/MWh, a GHG credit rate of €50/tCO_2 and the application of banking supporting schemes/monetary policies enabling to faster meet NECP goals in 2030 [21], especially when reducing dependence on or abandoning fossil fuels, considering large-scale integration of RES is required, [29]. On the other hand, the cost of installation of the wind turbine at a given location does not depend only on the wind resource, but also on the structure of the turbine and the energy conversion technology, [30].

11 Future Work

Our future work will be focused on identifying an "optimized wind rating point" (OWRP) considering low wind class regions that employ different rated wind power turbines (MW), hub height, etc. being a pivotal starting point in sheltering the identified Albanian's potential of 7400 MW wind capacity, fully in line with sustainability and decarbonization (electrification of transportation and industry sector) ambition program in 2050.

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Contribution of Individual Authors to the Creation of a Scientific Article

- Andi Hida has carried out the simulation and numerical model, got the idea of the simulation, conceptualization and wrote the research article.
- Lorenc Malka has developed the mathematical model and has carried out the computer simulations in selected energy tools. He has participated in the conception of the system topology. He has collaborated with the writing and revision of the manuscript and supervised the numerical study made the figures and editing.
- Rajmonda Bualoti has contributed to reading, advice, and formal suggestions at the first stage of the problem conceptualization.

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Conflict of Interest

The authors have no conflicts of interest to declare.