Preliminary Techno-Economic Analysis of Wind Power Plant Development in Central Java

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Abstract. The wind energy potential in Central Java offers promising opportunities for utility-scale wind power development. This study evaluates the techno-economic feasibility of four candidate sites using the System Advisor Model, analyzing turbine capacities from 500 to 2000 kW and total plant capacities of 30, 50, and 70 MW. Technical assessments include wind resource analysis, turbine layout design, and system loss estimation. Wlahar Village in Brebes emerges as the most promising site, with an average wind speed of 6.2 m/s and a net capacity factor of 37%. Two financing structures were compared: a 70% debt scheme and a conservative DSCR-targeted approach. Although the 70% debt model yields attractive metrics (LCOE 5.62 ¢/kWh, NPV USD 71.95 million, IRR 9.38%), it is financially unfeasible due to a low DSCR of 0.62. In contrast, the conservative scheme, designed to meet a minimum DSCR of 1.25, achieves a viable NPV of USD 61.31 million and an IRR of 7.05%. Grid connection costs increase total capital expenditure by approximately 1.46% but do not significantly affect feasibility. Overall, Wlahar demonstrates strong technical performance and economic viability under conservative financing assumptions, supporting its potential for wind power development in Central Java.

1 Introduction

Indonesia is an archipelagic country with abundant renewable energy resources, including wind energy. However, the utilization of this resource remains minimal. According to the Indonesia Energy Outlook 2023 published by the National Energy Council (DEN), the nation's technical potential for wind energy increased sharply from 60.6 GW in 2020 to 154.9 GW in 2021 [1]. This significa*nt increase was primarily due to the inclusion of offshore wind potential, which had not been fully accounted for in previous assessments. Despite this vast potential, the actual deployment of wind power plants contributes only about 0.06% of the national primary energy supply as of 2023, highlighting a substantial gap between potential and implementation [2].

One of the main challenges hindering development is the lack of comprehensive, site-specific techno-economic feasibility studies, which discourages investment. While several areas in Central Java record suitable average wind speeds between 6 and 8 m/s, few

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systematic studies have evaluated project feasibility in the region [3]. Central Java offers strategic advantages for onshore wind development, including ample land availability and proximity to high-voltage transmission networks, representing an accessible starting point to address the national energy gap.

This study aims to fill the current knowledge gap by focusing specifically on the feasibility of onshore wind projects within this promising region. To achieve this, a techno-economic analysis was conducted for four selected sites in Central Java : Wlahar Village (Brebes), Pamulihan Village (Brebes), Cipanjang Village (Brebes), and Blingoh Village (Jepara). Site selection was based on a five-year period of wind speed data (2017–2021) from the NREL Wind Resource Database, transportation accessibility, and proximity to the 150 kV power grid [4]. The analysis was performed using the System Advisor Model, which holistically integrates technical and financial evaluations [5]. The study examines various wind farm capacity scenarios (30 MW, 50 MW, and 70 MW) with turbine capacities ranging from 500 kW to 2000 kW. Furthermore, two primary financing approaches were compared: a conventional 70% debt scheme and a more conservative scheme designed to maintain a minimum Debt-Service Coverage Ratio (DSCR) of 1.25, a common threshold required by lenders for project financing [6], [7].

2 Methodology

This study adopts a quantitative, simulation-based approach using the SAM software developed by NREL to evaluate the technical and economic feasibility of Wind Power Plant (WPP) development in Central Java. Secondary wind potential data were obtained from the Wind Resource Database (WRDB) and five-year climate data [4].

2.1 Technical Analysis

The technical evaluation focused on site selection, resource assessment, turbine configuration, and system loss estimation.

2.1.1 Site Selection and Resource Assessment

Four potential sites in Central Java were identified for analysis covering Wlahar (Brebes), Pamulihan (Brebes), Cipanjang (Brebes), and Blingoh (Jepara). The selection was guided by the site suitability assessment criteria outlined in the IEC 61400-15-1 standard [8]. Key selection parameters included an annual average wind speed of ≥6.0 m/s, low turbulence intensity, flat topography, accessibility for transport, and proximity to the PLN electrical grid to minimize interconnection costs [9]. Meteorological data, including hourly wind speed, air temperature, and atmospheric pressure, were sourced from the Global Wind Atlas and NREL's Wind Resource Database for hub heights of 40 m, 80 m, 120 m, and 160 m. Since pressure data were limited, interpolation was used to estimate air pressure at specific turbine hub heights with a high degree of accuracy (R^2 = 0.9982).

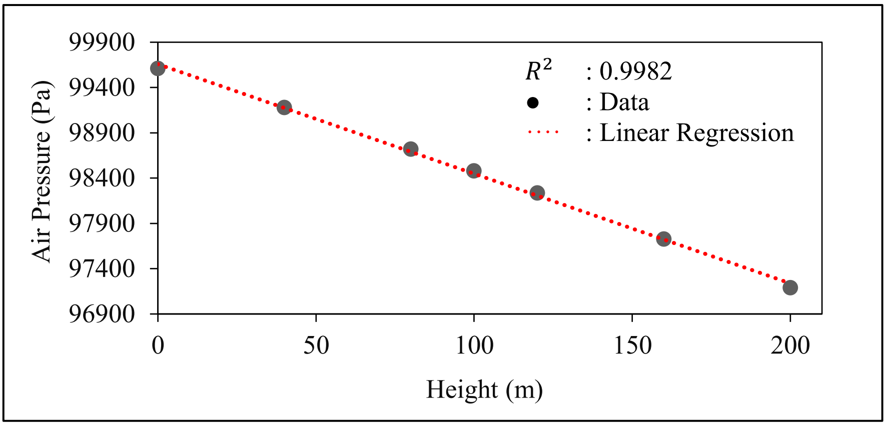

Fig. 1. Linear Regression of Air Pressure.

2.1.2 Turbine Selection & Layout Design

The study did not involve designing a new turbine; instead, it utilized a library of commercial off-the-shelf turbines available in SAM. Four distinct turbine power ratings were analyzed: 500 kW, 1000 kW, 1500 kW, and 2000 kW. These turbines were simulated across three different plant capacity scenarios: 30 MW, 50 MW, and 70 MW. The turbine layout for each site was optimized to maximize energy capture and minimize wake-induced losses. This was achieved by aligning the turbine rows with the dominant wind direction identified from the wind rose data. Standard industry spacing was applied, with a distance of six times the rotor diameter (6D) between turbines in the same row and three times the rotor diameter (3D) between rows [10].

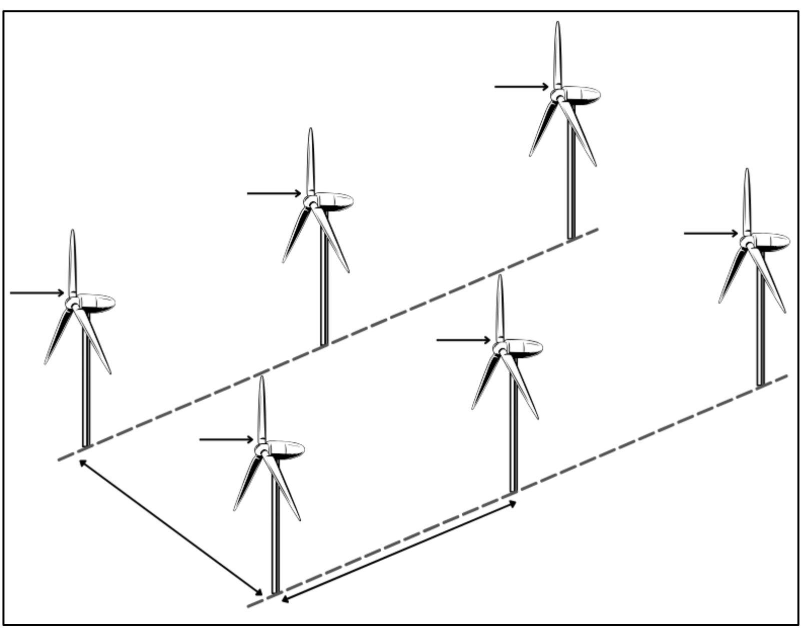

Fig. 2. Wind farm spacing [10].

2.1.3 System Loss Analysis

System losses were incorporated into the simulation to ensure a realistic energy output prediction. The loss assumptions were adapted from NREL's definitive report [11]. The major loss categories included:

- Wake losses: 4.3% (from interactions between turbines).
- Availability losses: 3.1% (due to turbine maintenance, grid downtime, etc.).
- Electrical losses: 1.5% (from cabling and power conversion).
- Turbine performance losses: 3.3% (deviation from ideal power curve).
- Environmental and curtailment losses: 1.3% and 1.0% respectively.

The total estimated system losses ranged from 10% to 15%, which also included an annual degradation factor of 0.64% [12].

2.2 Financial Analysis

The financial analysis was conducted within System Advisor Model (SAM) to evaluate the economic viability of the project using key financial metrics, Levelized Cost of Electricity (LCOE), Net Present Value (NPV), and Internal Rate of Return (IRR) [13].

2.2.1 Cost Assumptions and Financial Parameters

The financial model was built on the following core assumptions:

- **Capital Expenditure (CapEx)**
  Base costs for turbines and balance-of-plant were derived from the NREL Annual Technology Baseline (ATB) 2024 for onshore wind [14]. This was supplemented with project-specific costs, including land acquisition, which was assumed at Rp550,000/m² based on an assessment of local market rates in the project area.
  An additional Rp42 billion (USD 2.53 million) was budgeted for grid interconnection. This figure represents a comprehensive estimate for the construction of the 14-km, 150 kV transmission line, derived from the average per-kilometer cost of similar, completed projects in Indonesia. It is assumed to cover primary components such as towers and conductors, but does not explicitly include Right-of-Way (ROW) acquisition or substation upgrade fees.
- **Operational Expenditure (OpEx)**
  A fixed OpEx of $37 USD/kW/year was assumed, covering full-service contracts, staffing, and routine maintenance.
- **Financial Parameters**
  The analysis period was set to 30 years, with an annual inflation rate of 1.57%, a nominal discount rate of 3.32%, and a corporate income tax rate of 22%.

2.2.2 Financing Scenarios and Revenue

Two distinct financing scenarios were modelled to assess financial feasibility under different capital structures:

1. **70% Debt Scenario**
   A conventional structure where 70% of the total project cost is financed through debt and the remaining 30% through equity.
2. **DSCR-Targeted Scenario**
   A more conservative approach where the model determines the maximum debt proportion that can be sustained while maintaining a DSCR of ≥1.25.

Project revenues were calculated based on the Power Purchase Agreement (PPA) tariff stipulated in Indonesian Presidential Regulation No. 112/2022. For projects >20 MW, this is 9.54 ¢/kWh for the first 10 years and 5.73 ¢/kWh for years 11 through 30. The model also incorporated government fiscal incentives, primarily a 30% investment tax credit amortized over six years (5% annually) [15].

3 Results and Discussion

The techno-economic analysis indicates that the development of a utility-scale wind power plant in Central Java can be viable, provided there is strategic site selection and a conservative financing structure. This section presents the technical performance comparison across the four potential sites, evaluates the feasibility of two financing models, and examines the economic performance of the optimal configuration, including the sensitivity to grid connection costs.

3.1 Technical Performance and Site Selection

The technical simulation results underscored the critical importance of site-specific wind characteristics in determining project viability. Among the four locations, Location 1 (Wlahar, Brebes) was identified as the most technically superior site. Although Location 3 recorded a marginally higher average wind speed (6.27 m/s vs. 6.21 m/s), Location 1 achieved a significantly higher net capacity factor of up to 37%. This is attributed to its more advantageous wind speed distribution, with 27.7% of winds occurring within the turbine's optimal productive range of 5.70–8.80 m/s.

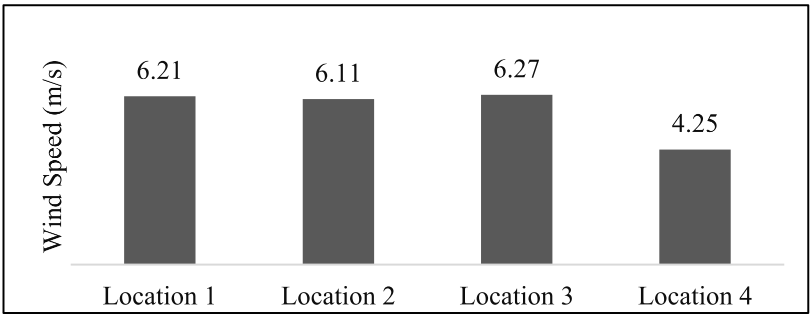

Fig. 3. Average Wind Speed

In contrast, Location 4 (Blingoh, Jepara) was found to be unsuitable for commercial development. Its low average wind speed of 4.25 m/s resulted in a net capacity factor of only ~10.1% and a Levelized Cost of Energy (LCOE) roughly three times higher than the viable sites, confirming the site's lack of commercial potential. The simulations for all sites incorporated a standardized set of operational loss assumptions, with the most significant being availability losses (3.14%), wake effect losses (4.3%), and turbine performance deviation (3.3%).

Table 1. Turbine Selection.

Rating (kW)	Type/Model	Annual Gross AC Energy in Year 1 (kWh)
500	EWT Directwind 54	263,359,000
	PowerWind 56	253,266,000
1000	Mitsubishi MWT 1000A	440,784,000
	Vergnet GEV HP (104.4dba)	373,572,000
1500	GE 1.5 xle	377,771,000
	Vensys 82	328,936,000
2000	Gamesa G114	154,540,000
	NREL 2000kW	151,474,000

3.2 Viability of Financing Structures

The financial feasibility was found to be highly sensitive to capital structure:

1. **70% Debt Scenario**
   Financially unfeasible despite higher theoretical NPV and IRR values, as the highest achieved DSCR was only 0.62, indicating inability to meet debt service obligations.
2. **DSCR-Targeted Scenario (≥1.25**)
   Proven feasible by limiting the debt-to-capital ratio to 38.75%, ensuring the project could consistently meet lender requirements. This conservative approach emerged as the only realistic financing option.

3.3 Economic Performance of the Optimal Configuration (Location 1)

Under the financially feasible DSCR-targeted financing scheme (DSCR ≥ 1.25), Location 1 demonstrates strong economic viability. It is important to note that all financial metrics presented in this section are comprehensive, incorporating the full capital costs including the USD 2.53 million for grid connection. The project's financial highlights under this viable scheme are as follows:

a. **Net Present Value (NPV)**
   The project yields a maximum NPV of USD 61.31 million, achieved with a 70 MW plant capacity using 500 kW turbines. The positive NPV across various configurations indicates the project's capacity to generate significant value over its operational lifetime.
b. **Internal Rate of Return (IRR)**
   The highest project IRR is 7.05%, corresponding to a 30 MW plant with 1500 kW turbines. While the non-viable 70% debt scheme projected a higher comparative IRR of 9.38%, the 7.05% return is considered viable under the assumed low-interest (0.3%) ODA loan. The discrepancy where the largest capacity (70 MW) yields the highest NPV but a smaller capacity (30 MW) yields the highest IRR is a standard outcome in project finance. NPV, as an absolute measure, is driven by the larger total cash flows of a bigger project, while IRR, a relative measure of efficiency, can be higher for smaller projects due to a lower initial capital outlay relative to its returns.
c. **Levelized Cost of Energy (LCOE)**
   The lowest achievable LCOE, inclusive of grid costs, is 5.85 ¢/kWh, obtained with a 30 MW plant using 1500 kW turbines. This cost is highly competitive within the

regional energy market, positioning the project as an economically attractive source of new generation.

Table 2. Economic Results – Location 1 (Wlahar)

Wind Farm Capacity	LCOE (¢/kWh)	NPV (Million USD)	IRR (%)	DSCR	Debt Ratio (%)
70 MW (70% debt scheme)	5,62	71,95	9,38	0,62	70
70 MW (DSCR ≥ 1,25)	6,31	61,31	7,05	1,25	38,75

3.4 Impact of Grid Costs and Economies of Scale

The integration of a 14-km, 150 kV transmission line added a fixed cost of approximately USD 2.53 million to the project's CapEx. This study demonstrates significant economies of scale, as the financial impact of this fixed cost is inversely proportional to the project's total capacity. For example, this additional cost increased the total CapEx by a variable percentage depending on the scenario, with an average increase of 1.46% noted for larger configurations. The effect is most evident in the NPV analysis: the NPV of a 70 MW project declined by only 2.81% due to grid costs, whereas a smaller 30 MW project experienced a more substantial reduction of 6.69%. This finding confirms that larger-scale projects are more financially resilient to fixed infrastructure costs, making them more robust and attractive to investors. While this preliminary study assumes that the 70 MW capacity is within the absorption limits of the local 150 kV transmission network, it is recommended that a more detailed grid impact study be conducted in subsequent stages to verify technical constraints regarding land availability and grid stability for the maximum proposed capacity.

4 Conclusion

This study concludes that developing a wind power plant in Central Java is technically and economically feasible, but its viability is critically dependent on strategic site selection and a conservative financing structure. The analysis identifies Wlahar Village, Brebes (Location 1) as the optimal site, possessing superior technical potential demonstrated by a net capacity factor of up to 37%, which was achieved with a 1500 kW turbine configuration.

The financial feasibility of the project hinges on the financing scheme. A high-debt model (70% debt) was proven unfeasible, as its DSCR consistently failed to meet the required threshold, with a maximum value of only 0.65—well below the bankable minimum of 1.25. Consequently, the only viable approach is a conservative scheme targeting a DSCR of 1.25 or higher, which supports an average debt portion of approximately 38.75%. Under this feasible scheme, the project's optimal financial outcomes vary depending on the specific project configuration, underscoring that the highest NPV and IRR are not achieved in the same scenario:

a. The highest NPV of USD 61.31 million is realized with a larger 70 MW plant capacity using 500 kW turbines.
b. In contrast, the highest IRR of 7.05% and the lowest LCOE of 5.85 ¢/kWh are both achieved with a smaller 30 MW plant capacity using 1500 kW turbines.

The project also demonstrated financial resilience to fixed infrastructure costs, such as grid connection, with financial models indicating greater robustness at larger scales (e.g., 70 MW). However, it must be noted that this is a finding from a preliminary techno-economic model. A full, bankable feasibility study would require a dedicated grid impact analysis to confirm the technical capacity of the local 150 kV network to absorb a 70 MW injection, which was beyond the scope of this initial assessment.

We would like to express our sincere gratitude to the National Renewable Energy Laboratory (NREL) for providing access to wind resource data and simulation tools. Special thanks are also extended to our colleagues and technical staff whose valuable insights and assistance greatly contributed to the success of this research.

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