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REVIEW

Life-Cycle Cost Drivers of Offshore Wind Turbines in Emerging Markets: Construction, Installation Logistics, and Financial De-Risking

Annisa Putri Purwanti , ***Mochammad Fathurridho Hermanto*** * , ***Nafisa Nandalianadhira***

Ocean Engineering Department, Institut Teknologi Sumatera, Lampung 35365, Indonesia

ABSTRACT

This investigation examines the life-cycle cost LCC framework for offshore wind farms under the particular constraints characteristic of emerging markets, with a focus on Southeast Asia. By integrating technical design parameters, tropical climatic conditions, and financial variables, this work identifies the principal determinant of project viability. The synthesis emphasizes how techno-economic constraints intersect with regional grid conditions in offshore wind market development, addressing an identified gap in the literature. Centered on Southeast Asia, it draws on evidence from Indonesia, Malaysia, and comparable tropical contexts to inform policy and investment decisions. Empirical analysis indicates that initial capital expenditure CapEx accounts for about 67% to 85% of the total cost structure in the contexts studied. Accordingly, the results suggest that financial de-risking measures and lower interest rates exert a more substantial impact on reducing the Levelized Cost of Energy LCOE. This work questions the global push toward mega-turbines in low-wind tropical settings, arguing that their substantial infrastructure demands can undermine economic efficiency. It instead advocates turbine configurations optimized for a higher rotor-to-generator ratio and installation approaches that maximize efficiency within limited weather windows. While larger rotors incur higher transport and logistics burdens in developing markets, a life-cycle cost assessment indicates that these costs are offset by gains in energy yield and

*CORRESPONDING AUTHOR:
Mochammad Fathurridho Hermanto, Ocean Engineering Dapartment, Institut Teknologi Sumatera, Lampung 35365, Indonesia;
Email: mochammad.hermanto@kl.itera.ac.id

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higher capacity factors when deployment is carefully planned. The results suggest that in developing economies, technical advances must be complemented by robust financial policies to achieve cost competitiveness, placing greater emphasis on financial optimization alongside technological improvements.

Keywords: Offshore Wind Turbine; Life Cycle Cost; Developing Countries

1. Introduction

Accelerating the global energy transition has become an urgent imperative to curb rising carbon emissions, which remain largely driven by fossil fuel use, especially in the electricity and construction sectors [1]. The 2022 Global Status Report for Buildings and Construction [2] shows that the buildings and construction sector accounted for more than 34% of global energy demand and about 37% of CO_2 emissions tied to energy consumption and industrial processes in 2021. This underscores the necessity of decarbonization through renewable energy as a pivotal element in meeting international climate goals. Consequently, demand is increasing for large-scale low-carbon electricity sources, with offshore wind development emerging as a key avenue [2].

Data published in the International Energy Agency (IEA) [3] indicate that wind energy accounts for 95% of total renewable energy growth, underscoring wind's pivotal role in advancing the sector. Wind energy offers a stable, large-scale generation trajectory, with onshore capacity projected to reach about 145 GW and offshore capacity around 212 GW by 2030 [3,4]. Offshore wind development in emerging Southeast Asian markets confronts challenges not fully captured in analyses focused on Europe and North America. Capital expenditure is higher due to expensive financing, underdeveloped supply chains, and limited port infrastructure. Moreover, the global shift toward larger turbines does not consistently align with regional wind speeds near 5–7 m/s, which can reduce energy output and jeopardize project viability. Operational costs are shaped by local grid tariffs and regulatory environments that differ from those in mature markets. Empirical evidence from Iraq shows that domestic electricity pricing below $0.041 per kWh renders both PV and wind investments economically unviable, underscoring tariff reform as a critical enabler of renewable deployment in developing economies [3–5].

Looking ahead, offshore wind is poised to remain a central driver of the global energy transition. The 2025 GWEC outlook [6], projects Europe will tender more than 51 GW of new capacity between 2025 and 2030, led by the United Kingdom through Contract for Difference CfD rounds, with Germany, Poland, and the Netherlands following. In Asia, an additional capacity of around 80 GW is expected by 2030, largely propelled by targets in Taiwan, Japan, and South Korea. Realizing these projections will hinge on overcoming key challenges, including port infrastructure limitations, supply chain uncertainties, and the advancement of floating wind technology for deep-water deployment [6].

Offshore wind projects require substantial upfront CapEx, which dominates their total cost. Analyses indicate that CapEx accounts for roughly 75% to 85% of the LCOE for offshore wind [7–9]. Typical CapEx levels are around 5,411 per kW for fixed bottom foundations and 7,349 per kW for floating platforms. Beyond construction, annual OpEx over a 25–30 year lifetime encompasses vessel rentals, labor, spare parts (gearboxes, generators, etc.), insurance, and administrative overhead [8–10].

Additional evidence from Dinwoodie and McMillan [11] indicates that OpEx contributes meaningfully to LCOE as well. Benchmarking shows an average annual OpEx of roughly $135 per kW for fixed-bottom installations and $108 per kW for floating turbines, which translates to indicative LCOE values of about $117/MWh and $181/MWh, respectively. A pronounced economy-of-scale effect is evident across turbine capacity classes: 20 kW units yield an LCOE near $240/MWh, 100 kW units around $174/MWh, and commercial-scale 1.5 MW turbines about $80/MWh [12]. This steep decline is largely driven by economies of scale, since the substantial upfront CapEx dominates the overall cost. In summary, both large CapEx and recurring OpEx keep offshore wind expensive, but larger tur-

bine sizes and advances in technology can drive down the cost per MWh over time [11,12].

Life cycle cost LCC analysis serves as a crucial tool for optimizing offshore wind turbine construction by prioritizing design and material efficiency to reduce costs without compromising structural integrity. For example, Ojo et al. [13] show that imposing a 10° static pitch angle on an OC3 spar platform (Case C) in a 30 MW (six turbine) farm reduced total platform costs from £222.16 million ($299.73 million) to £203.98 million ($275.20 million), roughly $290 M down to $265 M [13]. This illustrates how LCC-driven design choices can enhance economic viability. Simultaneously, financing conditions reflected by the Weighted Average Cost of Capital (WACC) critically influence life cycle costs; for instance, reducing the WACC from 10% to 5% has been shown to cut the levelized cost of energy by more than 30% [13,14].

Empirical investigations emphasize the necessity of site-specific LCC assessments. Data from active offshore wind installations show that actual installation costs can diverge from projections by roughly 6–10% due to weather-driven delays, vessel limitations, and seabed uncertainties [15]. Similarly, observed operational performance in the North Sea and Baltic Sea indicates that turbine output often underperforms relative to design expectations, with capacity factors reduced by about 3–8% under real atmospheric conditions [11,12]. These results highlight the importance of incorporating real-world data into LCC models rather than relying solely on theoretical assumptions. In sum, they support a comprehensive appraisal of all cost stages from material production and fabrication to transport, installation, and operation within an integrated LCC framework tailored to the conditions of emerging markets [11,12,15].

2. Methodology

To analyze and synthesize the literature on Life Cycle Cost LCC and the lifecycle of offshore wind turbines, a systematic review was conducted in line with PRISMA guidelines. The methodology comprises four distinct stages: (1) Identification, performing a structured search of the databases ResearchGate, ScienceDirect, Web of Science, and Google Scholar using a predefined keyword set; (2) Screening, evaluating titles and abstracts to remove duplicates and off-topic records; (3) Eligibility, assessing full texts against predefined inclusion criteria (publications from 2014 to 2025, cost-related content, offshore wind context); and (4) Inclusion, final selection of studies for synthesis and classification. The overall workflow and study-selection process are illustrated in **Figure 1** [16].

2.1. Classification Strategy

The classification strategy serves as a systematic methodological framework for organizing and analyzing the collected literature, taking into account the multiple factors that influence project cost components. This comprehensive framework enables researchers to identify patterns, trends, and pivotal drivers of construction cost variability, while also enabling cross-comparison of the diverse approaches employed in offshore wind turbine projects across the globe. It provides a structured analytical scaffold for understanding the multifaceted nature of offshore wind turbine construction costs, spanning dimensions such as baseline information, process-oriented viewpoints, and cost estimation methods.

Based on how the reviewed publications are applied, the research approaches are grouped into four main categories:

Utilization of Existing Data: The method is validated by leveraging historical data from previously documented offshore wind turbine projects.

1. Real-world project deployment: the method is applied in actual offshore wind turbine construction projects using empirical construction data.
2. Use of existing data: the method is validated by leveraging historical data from previously documented offshore wind projects.
3. Simulation of projected data: data are generated through modeling and simulation to assess the construction cost feasibility of planned offshore wind projects.
4. Conceptual study without application: the proposed method is not tested in practice but is evaluated via literature reviews, benchmarking, or theoretical mathematical approaches.

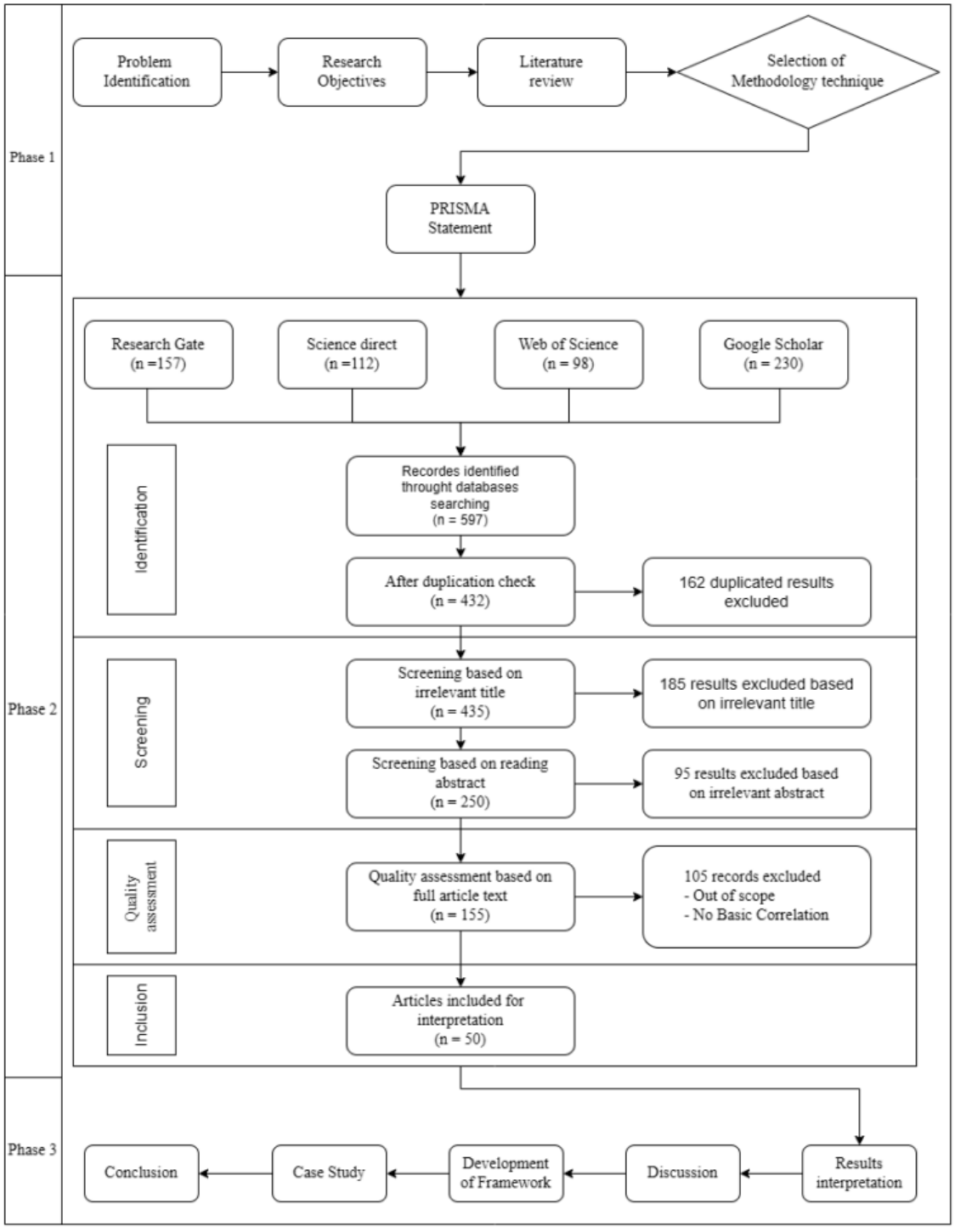

Figure 1. PRISMA flow diagram of the literature selection process.

The expected outcomes from applying these methods in offshore wind turbine construction cost research can be organized into three primary categories:

1. Real-world project deployment: the method is applied in actual offshore wind turbine construction projects using empirical construction data.
2. Use of existing data: the method is validated by leveraging historical data from previously documented offshore wind projects.
3. Simulation of projected data: data are generated through modeling and simulation to assess the construction cost feasibility of planned offshore

wind projects.

4. Conceptual study without application: the proposed method is not tested in practice but is evaluated via literature reviews, benchmarking, or theoretical mathematical approaches.

2.2. Search Strategy

The literature search strategy serves as a foundational methodological element of the systematic review, detailing explicit and reproducible steps to systematically identify relevant scholarly literature, minimize selection bias, and ensure thorough coverage. Transparency in this process underpins the credibility and scope of the review. The search protocol employed for the offshore wind turbine construction cost analysis study is designed to comprehensively capture all pertinent publications from a range of information sources. Literature retrieval is conducted via established scientific databases, including:

1. ResearchGate (www.researchgate.net);
2. ScienceDirect (www.sciencedirect.com);
3. Web of Science, and (https://wos-journal.info/);
4. Google Scholar (https://scholar.google.com/).

Keywords used for the literature search included offshore wind turbine economics, cost analysis, life cycle assessment, LCOE, CapEx, and OpEx. The temporal scope was limited to publications from 2014 to 2026 to align with evolving technologies and current policy contexts. An initial pass with a preliminary search string produced a baseline set of results from the identified sources, which then underwent systematic screening. This step enabled tuning of the review's inclusion criteria and iterative refinement of the search string to maximize retrieval effectiveness.

The search string is crafted to systematically identify cost-related information for offshore wind turbines across their entire lifecycle. This retrieval approach combines four core dimensions connected by the Boolean operator [17]. The resulting literature corpus specifically targets offshore wind turbine construction cost analytics, spanning CapEx through OpEx to comprehensive life cycle cost analyses. By strategically composing these search terms, a cohesive view of total offshore wind turbine construction costs emerges. As illustrated in **Figure 2**, the keyword co-occurrence analysis highlights the principal thematic relationships among construction, operation, and life-cycle cost studies [16,17].

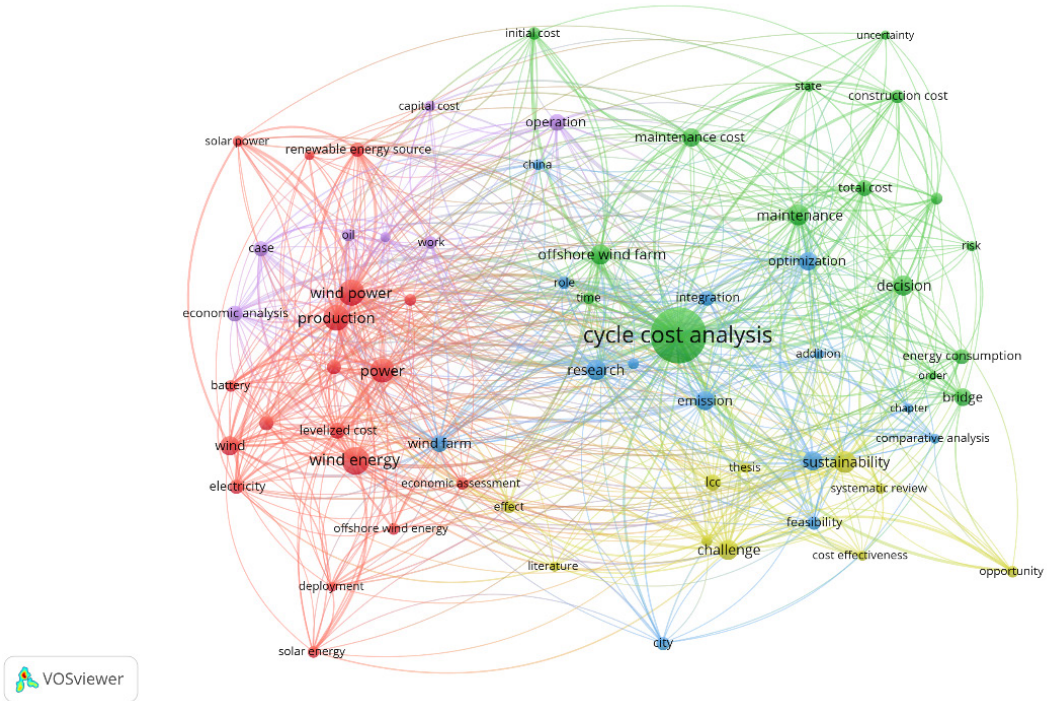

Figure 2. Mapping of keywords that frequently appear together.

A bibliometric analysis was conducted using VOSviewer to systematically map keyword co-occurrence patterns across the publication corpus. The approach employed a full counting method, assigning full weight to every instance of a keyword. The resulting network visualization captures patterns in offshore wind turbine life cycle cost analysis. From this conceptual network visualization, the constituent terms are organized into discrete thematic clusters as outlined in **Table 1**.

Table 1. Thematic clusters of offshore wind turbine life cycle cost research based on keyword co-occurrence analysis.

Cluster	Color	Main Focus	Keywords
1	Red	Production and energy resources	Wind energy, wind power, LCOE, grid integration
2	Green	Costs, risks, optimization	Total cost, construction cost, maintenance cost
3	Blue	Research methodology	Systematic review, comparative analysis
4	Yellow	Potential and integration of the project	Project benefit, LCC, sustainability
5	Purple	Economics and financing	Capital cost, financing, economic analysis

Overall, the network visualization shows that life cycle cost analysis functions as the central conceptual node linking disparate topical domains across the literature corpus, establishing itself as the leading methodological framework for evaluating both economic viability and sustainability dimensions of offshore wind turbine projects and their accompanying infrastructure.

Collectively, the literature delineates the LCC framework established in this review. First, CapEx consistently dominates lifecycle costs, accounting for roughly 67% to 85% of LCOE depending on project location, substructure type, and financing conditions. Second, financial variables, notably the Weighted Average Cost of Capital, exert a disproportionate influence on LCOE relative to technical improvements: reducing the WACC from 10% to 5% can yield LCOE reductions well over 30%, a gain that cannot be achieved through turbine scaling alone. Third, installation logistics emerge as the most regionally variable cost driver, with weather-window constraints and vessel availability creating cost differentials of up to 20% between European and Southeast Asian deployment contexts. Fourth, studies focusing on emerging markets consistently identify a mismatch between global turbine scaling trends and local low-wind regimes as a critical inefficiency, endorsing high rotor-to-generator ratio turbine configurations. Taken together, these findings outline a clear path toward cost-competitive offshore wind in non-traditional markets through coordinated financial de-risking, logistical optimization, and turbine configuration adaptation.

3. Literature Review

3.1. Cost Structure of Offshore Wind Turbine Projects

Offshore wind turbine project expenditures are largely driven by four CapEx stages: material production, fabrication, transportation, and installation. However, long-term project feasibility is strongly influenced by operational costs, particularly in emerging economies. Evidence from the Iraqi energy market illustrates this imbalance, where annual operation and maintenance expenses reach about $120/kW for wind turbines compared with annual expenses around $120 per kW for wind turbines, compared with roughly $10 per kW for photovoltaic systems, highlighting wind energy's greater reliance on specialized expertise and intricate logisticsroughly $10/kW for photovoltaic systems, reflecting the greater dependence of wind energy on specialized expertise and complex logistics

Offshore wind project expenditures are predominantly driven by four CapEx stages: material production, fabrication, transportation, and installation. Yet, long-term feasibility depends heavily on operating costs, especially in emerging economies. Evidence from Iraq's energy market demonstrates this imbalance, with annual operation and maintenance expenses around $120 per kW for wind turbines, compared with roughly $10 per kW for photovoltaic systems, highlighting wind energy's greater reliance on specialized expertise and intricate logistics [5]. **Table 2** synthesizes prior studies

by linking key cost components to the governing factors and cited sources. Numbers in the "References" column correspond to reference numbers listed in the References section at the end of this article.

Table 2. Literature review matrix.

Shared Dimensions	Cost Factors	References	Region	Capacity (MW)
Material cost	Manufacture of primary material components	Saleh et al. [5], Dalla Riva et al. [7], Myhr et al. [15], Dorrell and Lee [18], Kikuchi and and Ishihara [19], Arántegui et al. [20], Maienza et al. [21], Meißner [22]	Europe, Japan, US, China, Global	2.0–15 MW
Fabrication cost	Production scale, turbine design, and time	Myhr et al. [15], Kikuchi and Ishihara [19], Lacal-Arántegui et al. [20], Meißner [22], Zhang and Wang [23], Maienza et al. [24], Rashid et al. [25], and Hassan et al. [26]	Japan, Europe, Italy, China	5–15 MW
Transportation cost	Distance to location	Myhr et al. [15], Kikuchi and Ishihara [19], Lacal-Arántegui et al. [20], Zhang and Wang [23], Shields and Nunemaker [27], Sovacool et al. [28], Chartron [29], Pradana et al. [30], Sarker and Faiz [31].	Japan, Europe, US, China, Indonesia	2.0–15 MW
Installation cost	Installation method	Wiser et al. [10], Myhr et al. [15], Kikuchi and Ishihara [19], Maienza et al. [21], Zhang and Wang [23], Maienza et al. [24], Shields and Nunemaker [27], Sovacool et al. [28], Chartron [29], Pradana et al. [30], Wang et al. [32], Abir and Hossain [33], Aslubal et al. [34], Ashuri et al. [35], Blenkey [36]	Europe, US, Malaysia, Indonesia, China, Global	2.0–20 MW
O&M cost	Maintenance costs	Myhr et al. [15], Kikuchi and Ishihara [19], Maienza et al. [27], Alsubal et al. [34], Elnaggar et al. [37], Wang et al. [38], Lyu et al. [39], Ioannou et al. [40]	Japan, Norway, Italy, Malaysia	5–7 MW
End-of-Life cost	Removal of foundation/platform, recycling, and disposal	Myhr et al. [15], Kikuchi and Ishihara [19], Maienza et al. [27], Alsubal et al. [34], and Wang et al. [38]	Japan, Norway, Italy, Malaysia	5–7 MW

3.2. Material Production

The material production phase constitutes a foundational element of the offshore wind value chain, encompassing the manufacture of steel towers, concrete foundations, composite blades, and rare-earth generators, as illustrated in **Figure 3** [7]. However, projects in Southeast Asia and the Bay of Bengal must confront tropical-environment stressors unique to these regimes, such as high average humidity at about 79% and saline air that accelerates structural fatigue. To mitigate these constraints, turbine specifications should require marine-grade anti-corrosion coatings (for example ISO 12944 C5-M) and the adoption of innovative hydrophobic materials like graphene-enhanced epoxy to reduce water absorption and mold growth on blades. These measures are essential to sustain aerodynamic performance and prevent the 10–15% service life reduction typically observed when North Sea standards are applied blindly to tropical environments [7,33].

Figure 4 presents the proportional distribution of turbine expenditures across the selected reference years. When tower-related costs are excluded, 15 components together account for 78% of total CapEx for a 6 MW turbine in 2016, 80% for a 7 MW turbine in 2016, and 83% for a 7 MW turbine in 2019. The remaining share comprises ancillary components and other items outside the three primary modules, including hub, generator, and backend [22].

According to Nwokolo [41], scenario-based modeling of offshore wind turbine material substitution projects identifies potential cost-efficiency gains and reductions in mineral demand across the period 2023–2050 under specified policy assumptions. The model indicates that substituting boron with magnesium for aluminum could lower related costs by roughly 5% by 2030, and that nanostructured carbon composite and polymer materials may reduce total material expenditures by about 8% in boron content under the study's policy scenarios. Additionally, strategic substitution of neodymium and dysprosium could cut material demand by as much as 25%, yielding cost savings of 10–30%, depending on policy execution and the timelines for

technology adoption. These projections are explicitly contingent on scenario assumptions and hinge on factors such as global supply chain conditions, policy trajectories, and technology readiness levels that Nwokolo [41] itself acknowledges entail substantial uncertainty. This review does not independently validate these projections and lacks the original data or modeling capacity to assess their applicability to Indonesian offshore wind markets specifically. They are presented here as one set of scenario-based estimates drawn from the reviewed literature, not as conclusions derived from this paper's own analysis [41,42].

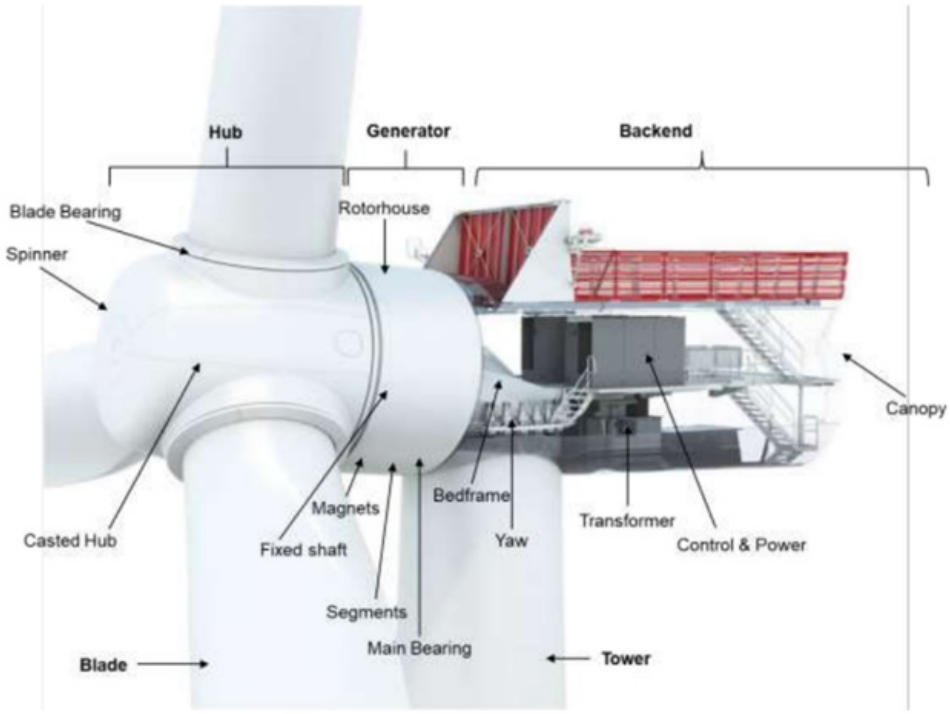

Figure 3. Main components of an Offshore Direct Drive Wind Turbine from Siemens Gamesa Renewable Energy (adopted from Meißner [22]).

Figure 4. Breakdown of cost drivers of a direct drive six MW offshore wind turbine in the year 2017 and a seven MW turbine in the year 2017 and 2019 (adopted from Meißner [22]).

Cost efficiency remains a central concern in the offshore wind turbine sector as the industry contends with volatile prices for raw materials and the imperative to stay price-competitive with other energy sources. The reviewed literature characterizes this as a persistent structural challenge [17]. Nonetheless, this review does not claim that any particular material or technological pathway will definitively resolve the issue, since such conclusions would require dedicated engineering analyses and supply chain assessments beyond the scope of a literature synthesis [17,18].

3.3. Manufacturing and Assembly

The fabrication phase is a pivotal transformation stage in which raw materials are converted into assembly-ready offshore wind turbine components. It encompasses multiple manufacturing processes, including primary material production such as steel, concrete, and composites; blade manufacturing; tower rolling; welding operations; nacelle assembly; and foundation fabrication, all of which demand stringent precision standards [27]. The fabrication costs listed in **Table 3** are anchored to European conditions in 2014 and should be regarded as reference values. More recent studies by Kikuchi and Ishihara [19] and Ioannou et al. [40] show that monopile costs increase nonlinearly with water depth and turbine size, with large-diameter monopiles (>9 m) becoming more expensive due to higher material prices and specialized production. Furthermore, Stehly et al. [12] report that fixed-bottom foundation costs for projects built between 2022 and 2024 in the US range from USD 500–800 per kW, reflecting inflation and the deployment of larger turbines. These updates support the classification by Myhr et al. [15] while underscoring the importance of using current cost data for future project evaluations [12,15,18,26,32].

Table 3. Production cost estimates for the bottom-fixed substructures (adopted from Myhr et al. [15]).

Component	Monopile	Jacket	
		Lattice Structure	Piles
Material consumption (tons)	1,200	510	315
Material cost ($)	1.41 million	0.60 million	0.37 million
Manufacturing complexity factor	100%	400%	100%
Manufacturing cost ($)	1.41 million	2.40 million	0.37 million
Total production cost ($)	2.82 million	3.00 million	0.74 million

Floating substructure configurations exhibit substantially wider cost variability across distinct design typologies, as illustrated in **Figure 5**. The WindFloat design emerges as the most economically demanding manufacturing alternative, with costs reaching €5 million ($0.514 million) [15]. Furthermore, the NREL Annual Technology Baseline [8] confirms that floating offshore wind LCOE remains broadly consistent with the upper range reported by Myhr et al. [15] at current pre-commercial scale, while projecting significant reductions toward approximately $74/MWh by 2035, contingent on supply chain maturation and commercial-scale deployment [8,15].

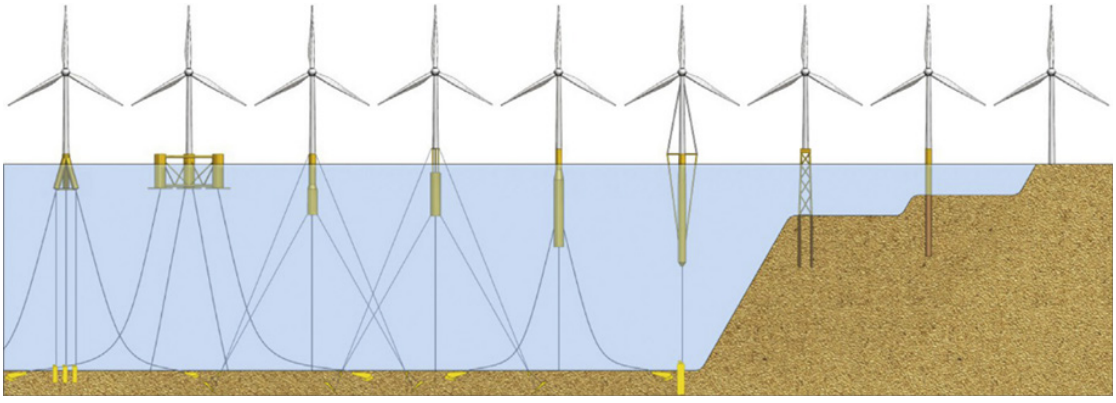

Figure 5. Illustration of the different concepts, from left to right; TLWT, WindFloat, TLB B, TLB X3, Hywind II, SWAY, Jacket, Monopile and the onshore reference (adopted from Myhr et al. [15]).

In aggregate, **Tables 3** and **4** show that manufacturing complexity and material volume are the primary cost drivers in offshore wind turbine foundation production. Accordingly, fabrication cost optimization can be achieved through the strategic adoption of modular design principles and serial production techniques. Modular design enables component standardization for mass production, while serial production accelerates the industrial learning curve, enabling substantial reductions in unit production costs [15].

Table 4. Production cost estimates for the floating substructures (adopted from Myhr et al. [15]).

Component	TLB B	TLB X3	Hywind II	WindFloat	SWAY	TLWT
Material consumption (tons)	445	521	1,700	2,500	1,100	417
Material cost ($)	0.52 million	0.61 million	2.00 million	2.94 million	1.29 M	0.49 million
Manufacturing complexity factor	110%	130%	120%	200%	150%	130%
Manufacturing cost ($)	0.576 million	0.797 million	2.401 million	5.884 million	1.942 million	0.638 million
Total production cost ($)	1.100 million	1.410 million	4.401 million	8.826 million	3.236 million	1.129 million

3.4. Transportation

Transportation and installation vessel costs are conventionally calculated based on daily charter rates. Based on Sarker and Faiz [31], the original figures were reported in 2017 prices as approximately €80,000/day for jack-up barges and €120,000/day for Self-Propelled Installation Vessels (SPIV), converted to USD using the 2017 average EUR/USD exchange rate of 1.13, yielding approximately USD $90,400/day and USD $135,600/day, respectively. Adjusted to 2025 values using the U.S. Bureau of Labor Statistics CPI, with a cumulative inflation factor of about 1.35 for the period 2017–2025, these rates correspond to approximately USD $122,040/day for jack-up barges and USD $183,060/day for SPIV. A comparative assessment of total costs associated with jack-up barge and SPIV deployment is presented in **Figure 6**. The analysis indicates that the most cost-efficient offshore wind turbine installation configuration involves jack-up barge transport carrying one turbine tower per voyage, corresponding to the fifth pre-assembly configuration [30,31].

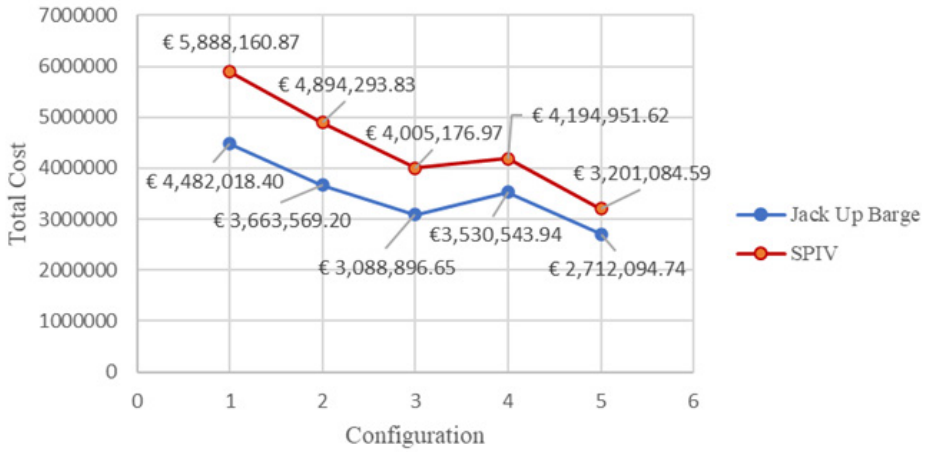

Figure 6. Comparison of both Scenarios for the total cost (adopted from Pradana et al. [30]).

To facilitate the operation of these vessels, ports supporting transportation and logistics activities must be equipped with specialized infrastructure, including adequate quayside depth, expansive staging areas, and high-capacity loading and unloading equipment. Lacal-Arántegui et al. [20] demonstrate, in their assessment of offshore wind turbine installation across Europe, that port facility constraints can increase project costs by 5–10% due to demurrage charges and installation schedule disruptions. Beyond port infrastructure considerations,

meteorological conditions and the distance to turbine installation sites constitute major logistical constraints influencing project costs. The key pre-assembly methods adopted in offshore wind projects are summarized in **Table 5**, while the impacts of port distance on transportation and installation costs are presented in **Table 6** [20].

Table 5. Popular pre-assembly methods for offshore (adopted from Sarker and Faiz [31]).

Pre-Assembly Method (j)	Sub-Assemblies	Number of Assembly Operations Done Onshore (mj)	Number of Separate Segments for Each Turbine (Nj)
Method 1	(Nacelle + hub + 2 blades) + tower in 1 piece + 3rd blade	4	3
Method 2	(Nacelle + hub + 2 blades) + tower in 2 pieces + 3rd blade	3	4
Method 3	(Hub + 3 blades) + tower in 2 pieces + nacelle	3	4
Method 4	(Nacelle + hub) + tower in 1 piece + 3 blades	2	5
Method 5	(Nacelle + hub) + tower in 2 pieces + 3 blades	1	6

Table 6. Effect of distance from port on transportation and installation (adopted from Sarker and Faiz [31]).

Turbine Class	Distance	Method 1	Method 2	Method 3	Method 4	Method 5
2.0 MW (150 turbines)	50	1,473,555	1,620,006	1,563,950	1,671,349	1,840,512
	100	1,590,650	1,737,101	1,651,773	1,741,603	1,928,327
	200	1,824,840	1,971,291	1,827,411	1,882,118	2,103,974
	250	1,941,935	2,088,385	1,915,234	1,952,372	2,191,789
2.3 MW (131 turbines)	50	1,381,659	1,524,595	1,524,595	1,583,922	1,745,607
	100	1,483,916	1,626,860	1,626,860	1,645,281	1,822,302
	200	1,688,447	1,831,382	1,831,382	1,767,999	1,975,691
	250	1,790,703	1,933,647	1,933,647	1,829,359	2,052,395
3.0 MW (100 turbines)	50	1,255,434	1,471,439	1,396,692	1,472,965	1,663,584
	100	1,333,503	1,588,534	1,474,752	1,519,806	1,741,645
	200	1,489,624	1,822,715	1,630,873	1,613,480	1,897,766
	250	1,567,684	1,939,810	1,708,942	1,660,313	1,975,835
3.6 MW (84 turbines)	50	1,233,851	1,444,292	1,381,499	1,492,372	1,660,583
	100	1,299,426	1,542,645	1,447,074	1,541,557	1,726,158
	200	1,430,575	1,739,369	1,578,214	1,639,911	1,857,307
	250	1,496,149	1,837,722	1,643,789	1,689,096	1,922,873
5.0 MW (60 turbines)	50	1,354,521	1,530,656	1,530,656	1,633,225	1,819,132
	100	1,424,774	1,600,910	1,600,910	1,668,348	1,865,965
	200	1,565,290	1,741,426	1,741,426	1,738,610	1,959,639
	250	1,635,544	1,811,679	1,811,679	1,773,732	2,006,481

Note: All cost values are reported in USD at 2017 prices, converted from EUR using the 2017 average exchange rate of EUR 1 = USD 1.13. To obtain approximate 2025 equivalent values, multiply by the CPI inflation factor of 1.35 (U.S. BLS, 2017–2025).

Figure 7 compares installation methods for fixed-bottom turbines with a rated capacity of 3.6 MW. The analysis indicates that Method 5 is the most cost-effective option, although it requires four onshore assembly stages. In contrast, Method 1 minimizes onshore assembly activities but incurs the highest costs due to the greater number of discrete segments that must be transported. These findings demonstrate that the trade-off between onshore assembly complexity and the number of transported segments is a critical determinant of offshore wind turbine installation cost-effectiveness [31].

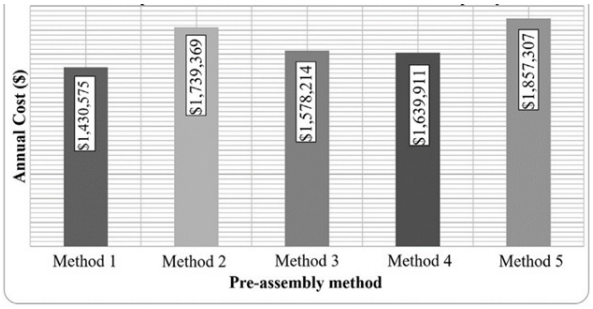

Figure 7. Transportation and installation cost for a fixed turbine (adopted from Sarker and Faiz [31]).

All cost figures presented in **Table 6** are reproduced from Rashid et al. [25] in their original 2017 USD values. The original source reported costs in USD based on the 2017 annual average EUR/USD exchange rate of approximately 1.13 [42]. Adjust these values to 2025 equivalent prices by applying a cumulative U.S. CPI inflation factor of approximately 1.35 for 2017–2025 [43]. As an illustrative example, the lowest reported total cost in **Table 6** is USD $1,233,851 (3.6 MW turbine, 50 km port distance, Method 1), which inflates to approximately USD $1,665,699 in 2025 prices (1,233,851 × 1.35). These inflation-adjusted estimates are presented for comparative context only; project-specific cost assessments should be conducted using current market data and prevailing exchange rates [42,43].

3.5. Installation

The installation phase constitutes one of the most critical stages in offshore wind turbine development, characterized by elevated risk exposure and substantial capital requirements. This phase exerts a direct influence on overall project performance across technical, temporal, and economic dimensions. Installation methodologies for offshore wind turbines vary significantly between fixed-bottom and floating configurations, each presenting distinct technical specifications, equipment requirements, and cost implications [15,21].

Fixed-bottom systems presented in **Tables 7** and **8** typically involve foundation placement such as monopiles, jackets, or gravity-based structures, followed by tower erection, nacelle lifting, and rotor installation. As documented by Shields and Nunemaker [27], the deployment of large-capacity turbines in the 12–15 MW range necessitates wind turbine installation vessels WTIVs with substantially greater crane capacity and hook height than those required for conventional 5–8 MW machines. Their process-based balance-of-system model establishes that crane lift capacity requirements scale significantly with turbine hub height, which increases from approximately 90 m for a 6 MW turbine to over 130 m for a 15 MW machine. These vessel specifications directly drive installation cost escalation, given that WTIVs capable of servicing next-generation turbines command substantially higher charter rates and remain limited in global supply [27].

Table 7. Estimated installation cost for monopile (adopted from Myhr et al. [15]).

Component	Operation	Count	Duration	Unit Cost ($)	OW	Total Cost ($)
Substructure installation	Quay-side lifts	2.00	0.13	306,000	75%	101,000
	Transportation	0.22	0.82		75%	73,000
	Substructure installation	1.00	2.00		50%	1,224,000
	Stationed personnel	30.0	2.95	578	52%	98,000
Turbine installation	Quay-side lifts	1.00	0.17	306,000	80%	66,000
	Transportation	0.11	0.82		80%	34,000
	Turbine installation	1.00	1.20		50%	734,000
	Stationed personnel	30.0	2.19	578	54%	70,000
Total installation cost per monopole wind turbine utilizing a specialized jack-up vessel						2,401,000

Note: All cost values are reported in USD at 2014 prices, converted from EUR using the 2014 average exchange rate of EUR 1 = USD 1.13. To obtain approximate 2025 equivalent values, multiply by the CPI inflation factor of 1.38 (U.S. BLS, 2014–2025).

Table 8. Estimated installation cost for jacket (adopted from Myhr et al. [15]).

Component	Operation	Count	Duration	Unit Cost ($)	OW	Total Cost ($)
Substructure installation	Quay-side lifts	2.00	0.13	306,000	75%	101,000
	Transportation	0.22	0.82		75%	73,000
	Substructure installation	1.00	3.00		50%	1,836,000
	Stationed personnel	30.0	3.94	578	52%	131,000
Turbine installation	Quay-side lifts	1.00	0.17	306,000	80%	66,000
	Transportation	0.11	0.82		80%	34,000
	Turbine installation	1.00	1.20		50%	734,000
	Stationed personnel	30.0	2.18	578	54%	70,000
Total installation cost per jacket wind turbine utilising a specialised jack-up vessel						3,046,000

Note: All cost values are reported in USD at 2014 prices, converted from EUR using the 2014 average exchange rate of EUR 1 = USD 1.13. To obtain approximate 2025 equivalent values, multiply by the CPI inflation factor of 1.38 (U.S. BLS, 2014–2025).

Feeder barge charter rates vary widely by market conditions, vessel type, and operating region, and should not be estimated solely as a fixed share of WTIV rates without empirical support. Although some studies, such as Ioannou et al. [40], adopt a 20% ratio as a simplifying assumption, this value is not based on verified market data. Shields and Nunemaker [27] reports feeder vessel rates ranging from USD $35,000 to $55,000 per day, aligning with an average estimate of around USD $40,000. Likewise, Chartron [29] shows that offshore logistics costs during construction can contribute 0.6% to 7.6% of total LCOE, indicating significant variability. Overall, feeder barge rates are better represented within a range of USD $30,000–$60,000 per day, with USD $40,000 serving as a reasonable midpoint for early-stage analysis. Over a full installation campaign, these costs can rise to about USD $1.5 million [27,29,40].

Floating offshore wind configurations predominantly rely on port-based assembly through quayside processes, followed by tow-out operations via tugboats to installation sites for mooring and anchoring. This methodology offers potential to mitigate weather window constraints and realize installation cost reductions ranging from 20% to 30% in water depths exceeding 60 meters. MacFarlane et al. [17] and Zhang and Wang [23] indicate that higher individual turbine capacity correlates with enhanced cost efficiency and faster project delivery. Supporting evidence from **Table 9** shows that scaling offshore wind installations to 1,000 MW achieves a unit cost of USD $1,883.64 per kW, a reduction of USD $216.70 per kW and about 10.3% relative to 400 MW installations at USD $2,100.34 per kW [24,27,32].

Table 9. Wind turbine installation and decommissioning costs (adopted from Wang et al. [32]).

Items	Costs (USD/kW)	
	400 MW	1,000 MW
Wind turbine	967.50	867.91
In-field collector lines	64.03	81.10
Transmission cables	156.51	129.47
Offshore booster stations	72.56	44.11
Onshore control centers	30.16	14.23
Wind turbine foundations	441.07	422.57
Wind turbine installation	128.05	120.94
Decommissioning	145.13	130.90
Other fees	95.33	71.14

Nevertheless, upscaling strategies do not consistently yield cost savings unless they are paired with advances in design concepts, materials, and technologies. Empirical evidence from Ashuri et al. [35] indicates that neglecting these factors renders upscaling ineffective for reducing installation costs. Accordingly, upscaling is most effective when implemented incrementally and integrated with ongoing conceptual and technological innovations, thereby mitigating the risk of cost escalation [35].

3.6. Operational Expenditure

The Operational Expenditure (OpEx) framework for offshore wind turbines is constituted by interdependent principal components, whereby individual components exhibit differentiated cost contributions to the cumulative annual operational budget allocation. **Table 10** delineates the total Operational Ex-

penditure (OpEx) for a 7 MW offshore wind turbine located in the waters of Kudat, Malaysia, assuming a monopile foundation, with an OpEx of USD 0.95 million/MW. The OpEx cost distribution, which is specific to the Malaysian grid regulatory context and the Kudat site conditions, indicates that approximately 45.3% of total annual OpEx is attributable to transmission tariffs charged by Tenaga Nasional Berhad (TNB) for national grid connectivity. This proportion reflects the mandatory grid access charge structure applicable to independent power producers in Peninsular Malaysia under the Single Buyer framework and is not directly representative of transmission cost burdens in other national grid systems. In jurisdictions with different electricity market structures, such as merchant markets in Europe or regulated bilateral contract systems in Indonesia, the relative weight of transmission costs within OpEx may differ substantially [34].

Table 10. Breakdown OpEx 7 MW (SWT-7MW-154) (adopted from Alsubal et al. [34]).

OpEx Components	Cost per MW Installed (USD/MW)	Contribution to OpEx %	Contribution to the Whole Life Cycle Costs %
C_{rent}	23,370	2.46%	0.65%
$C_{O\&M\text{-}ins}$	87,305	9.19%	2.42%
$C_{transmission}$	430,350	45.3%	11.93%
$C_{O\&M\text{-}indirect}$	60,325	6.35%	1.67%
C_{ProM}	188,100	19.8%	5.22%
C_{CM}	160,550	16.9%	4.45%

The OpEx distribution in **Table 10** must be interpreted within its original context, as it derives from Alsubal et al. [34], which analyzed a single offshore wind project in Kudat, Sabah, Malaysia under national regulatory conditions. The notably high transmission cost share of 45.3% reflects the Tenaga Nasional Berhad TNB Single Buyer tariff structure, where grid connection charges are linked to electricity value, unlike European systems in Germany and the United Kingdom, where transmission costs are typically below 20%. Because Indonesia had no operating offshore wind farms during the reviewed period, Ashuri et al. [35] and Ioannoue et al. [40] transmission expenses would instead follow PT PLN's contractual framework, making direct generalization inappropriate. In contrast, other OpEx elements, such as preventive maintenance 19.8%, corrective maintenance 16.9%, and insurance and indirect costs around 15% show greater cross-regional consistency, as they are primarily influenced by technology, logistics, and labor conditions rather than regulatory policy [31,41,44].

Maintenance constitutes the second-largest OpEx component, representing about 37% of total annual OpEx, followed by insurance at 9%, indirect maintenance at 6%, and lease fees at 3%. Cost estimates include port preparation expenses of roughly USD $1,000 per vessel visit in the Malaysian case [34], while maintenance operations remain highly dependent on weather constraints such as wind speed, wave height, and temperature conditions [8,34]. Empirical findings from Zhang et al. [8] in **Table 11** show that optimized maintenance scheduling can significantly reduce downtime, lowering annual energy losses by about 30%, equivalent to 0.5% of total generation or approximately USD $500,000, with wake-effect considerations contributing an additional 0.07–0.19% improvement in annual energy production [8,34].

Table 11. Downtime energy reduced due to consideration of wake effects (adopted from Zhang and Wang [23]).

Year	Saved Energy (MWh)	Equivalent Hours	Percentage of Annual Energy	Saved Money (USD)
2010	777	14.00	0.16%	$0.173 million
2011	354	6.55	0.08%	$0.079 million
2015	853	16.40	0.19%	$0.190 million
2016	325	5.65	0.07%	$0.073 million
2019	814	14.65	0.17%	$0.182 million

Outside of routine schedule-based maintenance strategies, the precision of turbine-level wind speed forecasting offers a significant avenue for improving O&M cost-effectiveness. Hou and Liu [45] establish that composite machine learning frameworks, which pair Transformer architectures with XGBoost-driven error correction, can produce short-term wind speed estimates with a root mean square error (RMSE) of less than 0.30 m/s across various temporal horizons. For offshore wind developers in emerging economies like Indonesia, where viable weather windows are often restricted to a narrow 30–45-day annual range, enhanced predictive accuracy facilitates more efficient vessel uti-

lization and minimizes standby expenses. Consequently, refined wind speed modeling enables more dependable maintenance planning, ultimately driving down the total O&M expenditure over the project's lifecycle.

WFLO serves as a strategic design-phase intervention aimed at mitigating energy deficits caused by wake interactions. In Rashid et al. [25], a hybrid PSO–GA methodology is introduced, integrating Particle Swarm Optimization with Genetic Algorithm mechanisms to refine turbine positioning. This technique resulted in wake-loss improvements of 24–27.3% compared to traditional configurations. Although individual turbine efficiency increases of 0.3–0.4% appear marginal, these increments yield substantial aggregate energy yields throughout a 25–30 year operational period. Such optimizations are particularly critical for offshore wind developments in emerging markets, where poor turbine density and a failure to align with regional wind regimes can drastically elevate the Levelized Cost of Energy (LCOE). Beyond basic spatial adjustments, advanced metaheuristic algorithms offer considerable potential for cost reduction within integrated renewable energy systems. Liu et al. [46] demonstrate that a fused Differential Evolution–Harris Hawks Optimization (DE-HHO) architecture, applied to microgrid dispatch involving wind, solar, gas, and battery storage, reaches convergence within 10 iterations. This framework achieved a 4.5% reduction in daily operational costs compared to standard Particle Swarm Optimization, arriving at a floor price of $20,221 against the $21,184 benchmark set by PSO. While initially conceptualized for microgrids, these multi-objective metaheuristic frameworks are highly relevant to the offshore wind industry, as managing distributed assets and storage alongside intermittent production constitutes a nearly identical scheduling challenge [25].

3.7. Key LCC Variable

Formally, the square–cube law implies two relationships:

$$P \propto D^2$$

And

$$M \propto D^2$$

where P is output power, M is mass, and D is rotor diameter. These scaling laws underpin the economic dynamics of MRWT research.

Wind turbine output scales with rotor diameter squared, while mass and production costs increase cubically, a constraint highlighted by Hassan et al. [26] as the primary economic driver behind multi-rotor wind turbine MRWT research. Blade mass exponents of 2.1–2.9 indicate that scaling penalties are moderated but not eliminated. Upscaling single-rotor systems, therefore, yields diminishing LCOE gains, since major components scale super-quadratically, reinforcing CapEx dominance in turbine economics. Although advanced materials such as carbon-fiber composites, thermoplastics, and HSLA steels may reduce mass by 10–25% [41] and are considered necessary for turbines above 5–7 MW [35], these benefits remain unverified within this review and depend on manufacturing maturity and supply-chain readiness. Consequently, the square–cube law remains a conservative foundation for LCOE evaluation, while material innovation should be regarded as a prospective rather than proven cost-reduction pathway [26,35,41].

Research by Ashuri et al. [35] demonstrates that square–cube law scaling becomes increasingly inaccurate for estimating mass and cost at higher turbine capacities when conventional steel-based assumptions persist, as blade and tower weights grow disproportionately in 10–20 MW systems, reducing anticipated performance gains. Consequently, the economic rationale for larger turbines primarily depends on Balance of System (BOS) cost reductions, as evidenced in **Tables 12** and **13** and empirically examined within the U.S. market by Shields and Nunemaker [27], whose findings offer broadly applicable cost-modeling insights [23,35]. Similar analytical approaches applied in emerging markets, including Iraq, employ standard financial indicators NPV, IRR, and PBP under a 4% discount rate and 20-year lifespan. However, results remain highly sensitive to local electricity tariffs and capital costs. These observations confirm that a reliable Life Cycle Cost LCC assessment must integrate localized economic parameters alongside technical scaling principles [5,27,35].

Table 12. Cost comparison of turbine components 5 MW, 10 MW, and 20 MW (adopted from Ashuri et al. [35]).

Rotor & Nacelle Components	5 MW	10 MW	20 MW	Scaling Ratio	Cost Implication Analysis
3 Blades	1,057.50	2,474.90	8,570.70	8.1×	Highly sensitive to size, advanced composite materials are required to reduce weight
Hub	158.3	324.2	1,037.50	6.6×	Significantly increased due to the greater moment load of the blade
Gearbox	877.2	2,085.00	4,955.00	5.6×	Increased complexity of mechanical power transmission
Generator	398	796.1	1,592.20	4.0×	Linear in power, good scaling efficiency
Power Electronics	393.2	786.4	1,572.80	4.0×	Linear in power
Total Capital Cost (TCC)	6,072.30	15,489.00	45,618.00	7.5×	Turbine costs per MW increase with size ($1.2M/MW → $2.2M/MW)

Table 13. Balance of station 5 MW, 10 MW, and 20 MW (adopted from Ashuri et al. [35]).

Balance of Station (BOS)	5 MW	10 MW	20 MW	Scaling Ratio	Cost Implication Analysis
Tower	968.9	3,765.60	12,497.00	12.9×	The main logistical challenge, the cost per ton of steel
Foundation	2,174.70	4,349.50	8,699.00	4.0×	High economies of scale, constant cost per MW
Turbine Installation	732.8	1,465.80	2,931.50	4.0×	Operational savings due to fewer turbines
Electrical Connections	2,063.50	4,127.00	8,253.90	4.0×	Significant efficiency in wiring
Total BOS Costs	5,834.90	11,539.60	23,009.00	3.9×	BOS per MW decreases, becoming the main economic justification for large turbines

According to Shields and Nunemaker [27], three principal dynamics fundamentally shape the economics of array cable systems within large-scale turbine developments. First, a significant increase in turbine capacity, such as an augmentation from 6 MW to 15 MW, directly correlates with a reduction in the number of required units, decreasing from 80 to 32 turbines. This subsequently curtails the cumulative array cable length from 65 km to 35 km, thereby reducing the overall volume of copper and insulation materials that must be procured. Second, the underlying technical trade-offs reveal that higher-capacity turbines generate elevated electrical currents, which in turn mandate the use of cables featuring enlarged cross-sectional specifications. Finally, in configurations spanning 8 MW and 12 MW, the economic efficiencies derived from reducing cable lengths are often offset by the increased unit costs associated with specialized, high-specification cabling [27].

Conversely, at the 15 MW capacity level, the reduction in string quantities continues to support favorable capital expenditure (CapEx) reduction trends. Critically, the terminal dynamic exerts the most profound influence on installation temporal efficiency, demonstrating a reduction exceeding 50%, specifically from 1,250 to 600 h. This efficiency gain is a direct consequence of the diminished number of termination points requiring operations by Cable Laying Vessels, leading to a substantial decrease in installation costs from $20 million to $8 million. Such reductions represent significant cost efficiencies, especially when considering the premium charter tariffs associated with specialized vessels. These interconnections between turbine capacity scaling and the economic dynamics of array cabling are quantitatively detailed in **Table 14**, which comprehensively illustrates the impact of increased turbine size on the total turbine count, aggregate array cable length, required installation time, and overall installation costs for a 475 MW offshore wind project [35].

Table 14. Relationship between turbine scale and array cable cost parameters (adopted from Ashuri et al. [35]).

Turbine Capacity (MW)	Rotor Diameter (m)	Number of Turbines	Total Cable Array Length (km)	Cable Installation Time (hours)	Cable Installation Costs (Million $)
6 MW	155	80	65	1.25	20
8 MW	180	60	Interpolated Data	Decreasing	Decreasing
10 MW	205	48	Interpolated Data	Decreasing	Decreasing
12 MW	222	40	Interpolated Data	Decreasing	Decreasing
15 MW	247	32	35	600	8

While Shields and Nunemaker [27] concentrate on array-cable dynamics, research by Kikuchi and Ishihara [19] establishes an analytical framework for evaluating the costs associated with bottom-mounted offshore wind turbine foundations, which it identifies as the most significant capital expenditure after the turbines themselves. The model indicates that water depth functions as a powerful cost multiplier, given that the volumes of steel and concrete required must grow nonlinearly to withstand overturning moments. These results have vital life-cycle cost (LCC) consequences for the transition to larger hardware; for instance, 15 MW turbines necessitate much more massive substructures to accommodate increased hub heights and higher thrust loads. Consequently, in deeper environments, the compounding costs of turbine upscaling and foundation expansion can negate the financial advantages gained through cable optimization. This makes the strategic choice between monopile, jacket, or tripod configurations a pivotal decision that must be integrated with turbine capacity projections [19,27].

Within the framework of Indonesia's emerging economy, the investigations conducted by Shields and Nunemaker [27] and Ashuri et al. [35] offer strong validation of international trends and provide empirical data concerning the deployment of 15–20 MW turbines. On the other hand, academic inquiries focused specifically on the Indonesian landscape highlight practical constraints that may hinder the immediate integration of high-capacity turbine systems. Research by Franika et al. [47] and Fauzi et al. [48] characterizes these technical impediments, establishing a contrast between global technological potential and localized implementation challenges [23,35,47,48].

The structural integrity of offshore wind turbines in cyclone-affected areas, particularly within the Bangladeshi context, underscores the requirement for engineering specifications that surpass standard IEC 61400-1 criteria to endure extreme wind gusts exceeding 70 m/s [33]. Expanding on this technical challenge, Franika et al. [47] investigate wind energy implementation in the Java Sea using a brownfield methodology centered on the repurposing of retired oil and gas infrastructure. While this strategy offers a pathway to reduce foundation expenditures, it introduces rigid constraints regarding permissible structural loads. Since these legacy assets were not originally designed to handle the sophisticated dynamic forces exerted by 15 MW turbines, the focus of economic optimization transitions from simply maximizing output to identifying configurations that respect existing structural tolerances. This highlights the necessity of harmonizing turbine selection with the specific limitations of localized infrastructure [33,47].

Conversely, as presented in **Table 15**, Fauzi et al. [48] investigate the feasibility of wind turbine deployment for rural electrification in regions such as Papua, Maluku, and Ujung Kulon. Rather than assuming the superiority of high-capacity units, their fiscal assessment utilizes a comparative evaluation of turbine models T1 through T7 to determine the most favorable Levelized Cost of Energy (LCOE). The results reveal substantial LCOE fluctuations between different models even when situated at the same site; in Papua, for instance, costs vary from 11.89 ¢/kWh to 14.23 ¢/kWh. This research demonstrates that the T2 model delivers the highest economic performance, confirming that within the logistical constraints of remote territories, supply chain logistics and the alignment of power curves with local wind profiles are more critical drivers of financial viability than the simple maximization of turbine scale [48].

Table 15. Turbine ID T2 (adopted from Fauzi et al. [48]).

Location	AEP (MWh)	CF (%)	COE (¢/kWh)	Local Electricity Tariff (¢/kWh)	Profit (%)
Papua	10,766.43	36.77	12.24	17.68	32.75
Maluku	8,155.58	27.87	14.93	21.14	29.34
Ujung Kulon	6,680.40	22.82	17.71	7.06	–159.02

As reported by Langer et al. [44], while the average offshore wind speeds in Indonesia (5.6–6.9 m/s at a 100 m hub height) are considerably lower than those found in the North Sea (9–10 m/s), this disparity in velocity does not necessarily disqualify offshore wind developments. Significantly, Langer et al. [44] differentiate between a low-mean-wind-speed environment and an unprofitable one: the first is an inherent meteorological trait, whereas the second depends largely on turbine selection. Their research indicates that financial sustainability can be reached when rotor design is specifically engineered to maximize energy harvest under moderate wind conditions, as opposed to deploying turbine specifications intended for high-velocity wind regimes [44].

At an altitude of 100 m, average wind speeds are recorded at 6.94 m/s in Papua, 6.05 m/s in Maluku, and 5.66 m/s in Ujung Kulon. These figures represent a marked decline when compared to the 9–10 m/s benchmarks typical of the North Sea. Given that wind power density follows a cubic relationship with velocity, expressed as ($P \propto v^3$), a drop in wind speed from 10 m/s to 7 m/s results in a reduction of energy production potential by approximately 65% [48].

To mitigate these constraints, Langer et al. [44] and Fauzi et al. [48] advocate for low Specific Power turbine deployment. These configurations employ disproportionately large rotor diameters relative to generator capacity ratings, thereby facilitating enhanced energy capture efficiency under low wind velocity conditions. This approach demonstrates efficacy, with Papua installations projected to attain Capacity Factors of 39.11% [48]. CF values approaching 40% are globally competitive and are comparable to performance levels recorded in subtropical wind farms and mature North Sea projects operating under favorable financial conditions. Rather than characterizing this outcome as an exception to a low-resource constraint, the 39.11% figure should be read as direct empirical evidence that Indonesian offshore locations are not inherently low-yield: with appropriately matched rotor technology, capacity factors fully consistent with international benchmarks are achievable. The distinction, therefore, lies not in the resource itself but in the choice of turbine configuration [44,48].

Although low-specific-power turbines improve energy capture in tropical regions, their large dimensions create substantial logistical constraints. Turbines rated at 3–5 MW with rotor diameters of 130–175 m require transport of blades exceeding 80 m and roughly 25 t, necessitating specialized permits, modified transport routes, and port upgrade conditions met by fewer than ten Indonesian ports, with upgrade costs estimated at USD 5–25 million each. Hassan et al. [26] identify blade transportation as a central driver of multi-rotor turbine research, noting that blades beyond 100 m generate over-sailing fees and specialized logistics costs that increase CapEx prior to installation, whereas modular multi-rotor designs may alleviate these constraints [29,30]. Installation complexity further escalates costs, as heavier lift vessels raise jack-up barge rates by 15–25% and limited weather windows of 30–45 operational days annually add approximately USD 80,000–200,000 per turbine [26,29,30].

Evaluating whether higher logistics costs outweigh the energy benefits of low specific power turbines requires a unified LCC perspective. For a typical 100 MW shallow-water project in Indonesia, a standard 4 MW turbine (≈340 W/m^2) with a 28–30% capacity factor would generate about 246–263 GWh/year, while a 3 MW low specific power design (≈210 W/m^2) could reach 36–39%, producing 315–341 GWh/year -an increase of roughly 28–30% [48]. The larger rotor raises transport and installation costs by an estimated USD 3–8 million at the farm level, equivalent to about 0.5–1.5 USD/MWh over 25 years at 10% [29]. However, the improved energy output reduces LCOE by around 8–18 USD/MWh, clearly outweighing the added logistics cost. This advantage can shrink in areas with limited port capacity or short weather windows, where cost premiums increase. In such cases, solutions like port upgrades or pre-assem-

bly methods, such as the Bunny Ear approach [29], become important. Overall, low specific power turbines remain economically beneficial if logistical constraints are addressed early in project planning [29,48].

This assertion receives corroboration from Maienza et al.'s [21] sensitivity analysis. Their floating turbine research establishes Capacity Factor as the paramount technical variable determining LCOE, demonstrating primacy over CapEx mitigation strategies. Consequently, marginal CF enhancements of 1–2% realized through high-performance rotor technology adoption manifest superior LCOE reduction efficacy relative to structural component expenditure optimization initiatives [21,27].

A frequently neglected yet critically significant external factor is installation vessel availability. Pradana et al. [30] established that despite SPIV vessels incurring approximately $588,425 additional costs, they achieve 7-day time savings, equivalent to 20% total duration reduction. This consideration assumes heightened importance in Indonesian contexts where monsoonal wind patterns precipitate sudden installation window closures presented in **Table 16**. Chartron [29] substantiates this position, revealing logistics contributions of 7.6% to aggregate LCOE, with meteorological delays constituting principal cost inefficiencies throughout construction phases [29,30].

Table 16. Comparison of logistics and installation scenarios in Indonesian waters (adopted from Pradana et al. [30]).

Logistics Scenario	Vessel Type	Configuration Strategy	Project Duration	Total Cost	Trade-off Analysis
Scenario 1 (Cost Optimal)	Jack-Up Barge	Configuration 5 ("Bunny Ear")	34 Days	$3.18 million	Most economical if the weather window is available for more than one month, high risk of downtime.
Scenario 2 (Optimal Time)	SPIV	Configuration 5 ("Bunny Ear")	27 Days	$3.77 million	Saving 7 crucial days. The additional cost of €0.5 million serves as weather "insurance."
Comparison Scenario	Jack-Up Barge	Configuration 5 (Separated)	36 Days	$3.33 million	Slower and more expensive than "Bunny Ear," demonstrating the inefficiency of conventional methods.

Langer et al. [44] identify a financing trap in developing countries, where offshore wind turbine projects face substantially higher compared to Europe and China, which range between 4–6%. Research by Alsubal et al. [34] in Malaysia estimates discount rates at 7.84%, while various renewable energy studies in Indonesia typically employ assumptions of 10–12% due to elevated market and technology risk perceptions. This elevation substantially increases LCOE, given that offshore wind's capital-intensive characteristics are dominated by upfront CapEx. Langer et al. [44] emphasize that reduction through policy interventions such as government guarantee mechanisms or green financing instruments proves more effective in reducing electricity costs than technical improvements in turbine design [15,34,44].

The correlation between the accessibility of green finance and the feasibility of energy projects is reinforced by firm-specific data. Hou and Liu [45] demonstrate that the Green Finance Index (GFI) serves as a mediating variable between a company's environmental spending and its overall commercial performance. This suggests that consistent capital allocation toward ecological goals fosters institutional credibility among green lenders, which subsequently lowers the cost of borrowing. For offshore wind operators in Indonesia, these findings imply that robust environmental initiatives and clear ESG reporting can facilitate better access to low-interest green bonds and funding from multilateral development banks. Such strategic financial positioning directly mitigates the "financing trap" that typically jeopardizes project bankability when the Weighted Average Cost of Capital (WACC) exceeds a critical threshold of roughly 10%.

Three financing approaches have proven effective in lowering WACC for offshore wind and can be applied in Southeast Asia. First, government-backed Power Purchase Agreements (PPAs) or Contracts for Difference (CfDs) reduce revenue risk by guaranteeing fixed prices over 15–25 years; for example, the UK's CfD scheme lowered prices from about GBP 120/MWh in 2015 to GBP 37–44/MWh by 2022, cutting it by 3–4 percentage points [12]. Similar models could be implemented in Indonesia and Malaysia through PLN and TNB with sovereign guarantees. Second, blended finance that combines concessional loans from institutions like the ADB or

World Bank with commercial debt can reduce borrowing costs to around 4–6%, lowering LCOE by 15–25% compared to fully commercial funding [44]. Third, sovereign-backed green bonds provide access to cheaper international capital, often 50–150 basis points below domestic rates; Indonesia's green sukuk framework already offers a pathway to support offshore wind projects with minimal regulatory adjustment [12,44].

Stehly et al. [12] show that in mature offshore wind markets such as the United States and Northern Europe, financing has been reduced to around 4–6% mainly through financial de-risking rather than technological advances. This has been achieved using government-backed offtake agreements, green bonds, and blended finance structures that provide revenue certainty and lower investment risk. For example, the US relies on state-level mandates and fixed-price Renewable Portfolio Standard (RPS) contracts, the UK uses CfD auctions with long-term price guarantees, and Germany and the Netherlands utilize concessional financing through institutions like KfW. In each case, government support reduces the risk premium faced by investors, lowering overall financing costs. This highlights that institutional financing mechanisms rather than hardware cost reductions identified by Myhr et al. [15] are now the key factor determining offshore wind feasibility, particularly in emerging markets. **Table 17** demonstrates that CapEx contributes 67% of total costs, where each percentage point increase in loan interest rates inflates two-thirds of the total cost structure. Based on **Table 17**, LCOE in Malaysia is USD 127.58/MWh or approximately 14.95 ¢/kWh. This value aligns with Fauzi et al.'s [48] study for Papua at 11–14 ¢/kWh, providing consensus regarding baseline offshore wind turbine pricing under current financial conditions [12,15,48].

Table 17. Life Cycle Cost (LCC) Structure of Offshore Wind Turbine (adopted from Alsubal et al. [34]).

Cost Components	Proportion of LCC Total	Phase/Activity Details	Value Estimate (USD/MW)
Capital Expenditure (CapEx)	67%	Manufacturing and procurement cost dominance	2,404,659
Production & Acquisition	47%	Purchase of turbines, foundations, electrical systems	1,703,412
Pre-development	11%	Feasibility studies, permits, site surveys	381,932
Installation & Commissioning	9%	Vessel charter, offshore construction	319,315
Operation & Maintenance (OpEx)	26%	Operational costs for 25 years	950
Decommissioning	7%	Dismantling and restoration of end-of-life sites	252,033
Total LCOE		Average electricity cost	127.58/Mwh

Sensitivity analysis of floating offshore wind turbines identifies the weighted average cost of capital (WACC) and capacity factor as the two predominant parameters, demonstrating substantially greater influence than platform material expenditures or cable efficiency metrics. This finding emphasizes that Indonesia's optimal strategy transcends purely technical innovation, and financial de-risking represents the most strategic intervention. Should decline from 10% to developed-nation benchmarks of 5%, Indonesian offshore wind LCOE exhibits potential for dramatic reduction below 9–11 ¢/kWh absent significant turbine technological alterations. Conversely, without financing optimization, even cutting-edge technologies, including 20 MW turbines or Bunny Ear installation methodologies, cannot achieve cost competitiveness with conventional generation alternatives.

Lowering financing costs in Indonesia requires three sequential policy steps. First, revenue risk must be reduced through long-term power purchase agreements offered by PT PLN or another state entity at fixed tariffs, similar to the UK's CfD approach. Second, credit risk should be addressed by allocating concessional funding from MDBs such as ADB's OCR or ACGF specifically to offshore wind projects. Third, currency risk must be managed, as projects earn in IDR but rely on USD-based equipment and financing; this can be mitigated through government-backed foreign exchange guarantees or swap facilities, which would remove the current 1–2% cost premium for international lenders. As shown in

Table 18, most reviewed studies rely on simulations or secondary data, with cost estimation as the main focus. Research on Southeast Asia, particularly Indonesia and Malaysia, is largely based on real project applications, while studies from Europe and the US are more conceptual or comparative, revealing a lack of region-specific empirical cost analysis that this review aims to address.

The cost and technical characteristics discussed across the preceding scenarios are consolidated in **Table 19**. It maps four foundation types against their respective water depth ranges, indicative LCOE, CapEx per kW, installation approach, and suitable turbine class for emerging market conditions. All CapEx figures reflect 2017–2024 price levels, and an uplift of 3–5% above benchmark values should be factored into any site-specific cost projection.

Table 18. Summary of reviewed studies by methodological category.

Authors	Study Focus	Application Type	Methodological Category
Myhr et al. [15]	LCOE comparison for floating offshore wind turbine concepts (lifecycle perspective)	Utilization of Existing Data	Cost Estimation and Prediction
Kikuchi and Ishihara [19]	Engineering model for initial capital cost of bottom-mounted offshore wind farms	Real-world Project Application	Cost Estimation and Prediction
Lacal-Arántegui et al. [20]	Improvements in offshore wind installation time (87 wind farms, 2000–2017)	Utilization of Existing Data	Evaluation and Benchmarking
Alsubal et al. [34]	Whole LCC assessment of offshore wind farm, Kudat, Malaysia	Real-world Project Application	Cost Estimation and Prediction
Shields and Nunemaker [27]	Process-based balance of system cost model for offshore wind (US)	Projected Data Simulation	Cost Estimation and Prediction
Ioannou et al. [40]	Parametric CAPEX, OPEX, and LCOE expressions based on global deployment parameters	Utilization of Existing Data	Cost Estimation and Prediction
Sovacool et al. [28]	Cost overruns and risks in construction of 51 onshore & offshore wind farms	Utilization of Existing Data	Evaluation and Benchmarking
Maienza et al. [21,24]	Sensitivity analysis and feasibility of floating offshore wind farm cost parameters	Projected Data Simulation	Visual Cost Representation
Chartron [29]	Evaluating and improving logistics costs during offshore wind turbine construction	Utilization of Existing Data	Evaluation and Benchmarking
Sarker and Faiz [31]	Minimizing transportation and installation costs for turbines in offshore wind farms	Projected Data Simulation	Cost Estimation and Prediction
Pradana et al. [30]	Transport cost optimization of offshore wind turbine installation, Indonesian sea	Projected Data Simulation	Cost Estimation and Prediction
Wang et al. [32]	Optimization strategy for offshore wind power cost (scale and repowering)	Projected Data Simulation	Evaluation and Benchmarking
Ashuri et al. [35]	Multidisciplinary design optimization of large wind turbines (5–20 MW)	Conceptual Study (No Application)	Cost Estimation and Prediction
Fauzi et al. [48]	Implementation assessment of offshore wind turbines for remote electrification in Indonesia	Projected Data Simulation	Cost Estimation and Prediction
Langer et al. [44]	Offshore wind economic potential in low-wind-speed regions (Indonesia case)	Projected Data Simulation	Visual Cost Representation
Ojo et al. [13]	Techno-economic study of optimized floating offshore wind turbine substructure (FOWT)	Projected Data Simulation	Cost Estimation and Prediction
Dinwoodie and McMillan [11]	Operational strategies for offshore wind turbines to mitigate failure rate uncertainty on costs	Projected Data Simulation	Evaluation and Benchmarking
Franika et al. [47]	Technical and economic analysis of offshore wind power near Java Sea platforms (LCOE, NPV)	Real-world Project Application	Cost Estimation and Prediction

Table 19. Consolidated comparative summary of offshore wind foundation types, costs, and recommended turbine configurations for emerging markets.

Foundation Type	Water Depth Range (m)	Indicative LCOE (USD/MWh)	CapEx/kW (USD)	Installation Method	Recommended Turbine Class
Monopile	5–35	100–140	3,500–5,500	WTIV jack-up	3–5 MW; high rotor ratio; IEC Class III
Jacket/Tripod	30–60	130–180	4,500–7,000	WTIV + feeder barge	5–8 MW; monsoon-window scheduling
Semisubmersible (floating)	>60	117–181	6,500–9,000	Quayside assembly + tow-out	8–10 MW; PPA de-risking essential
Spar-Buoy (floating)	>100	150–236	7,000–10,500	Deepwater installation vessel	5–10 MW; high WACC mitigation required

4. Discussion

This section integrates the comparative cost table of offshore wind substructures and the Economic Decision Map based on Life Cycle Cost (LCOE versus water depth) to derive an integrated economic interpretation of foundation selection across bathymetric conditions. LCOE values in USD/MWh reflect total lifetime project costs, whereas the tabulated figures represent capital costs at the component level, specifically per turbine structure. To connect them, unit fabrication costs must be placed within a full wind farm context: assuming 100 turbines of 5 MW each, a 35% capacity factor, a 25-year lifespan, and a 10% financing rate, a foundation cost of about USD 2.82 million per unit contributes roughly 15–25 USD/MWh, aligning with observed variations across foundation types. The LCOE ranges are derived from integrated project analyses by the National Laboratory of the Rockies, Myhr et al., and Ioannou et al. [9,15,40], while per-turbine values function as input parameters rather than direct equivalents.

Figure 8 shows that water depth acts as the primary structural and economic boundary between fixed-bottom and floating technologies. At shallow depths of 20–35 m, monopile foundations exhibit the lowest LCOE (≈85–95 USD/MWh), consistent with **Table 20**, which reports relatively low production (~$2.8 million per turbine) and installation costs (~$1.8 million) at the component level (expressed in USD per turbine, sourced from Myhr et al. [20]); note that these per-turbine figures are not directly comparable to **Figure 8**'s LCOE values in USD/MWh, which integrate all cost components over the full project lifecycle as described above. This advantage is driven by simplified fabrication and shallow-water installation feasibility. However, beyond ~40 m, monopiles experience a sharp cost escalation due to nonlinear increases in steel tonnage and vessel requirements, as reflected by their depth sensitivity.

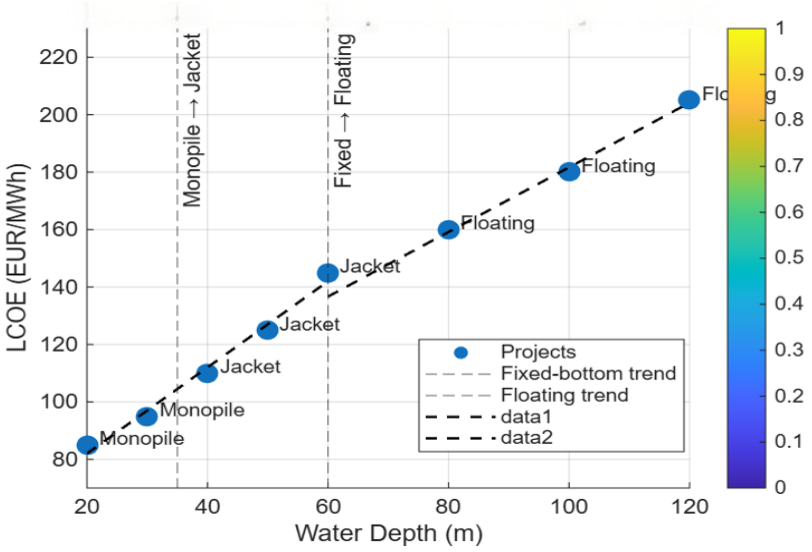

Figure 8. Graph Economic Decision Map based on LCC.

Table 20. Structural selection map based on depth and construction cost characteristics.

Structure Type	Approx. Production Cost (per Turbine)	LCOE (USD/MWh)	Installation Cost (per Turbine)	Typical Water Depth Range	Cost Sensitivity to Depth	Key Advantages	Main Limitations	Recommended Application Zone
Monopile (Fixed-Bottom)	~2.8 million USD	75–115	~1.8 million USD	Shallow (<35–40 m)	High (Exponential)	Lowest cost option in shallow waters; simple fabrication	Rapid material escalation at greater depths; installation vessel dependency	Nearshore shallow-water projects
Jacket (Fixed-Bottom)	~3.0 million USD	95–135	~2.3 million USD	Intermediate (35–60 m)	Moderate, relatively linear increase	Structurally stable in mid-depth; suitable for larger turbines	Higher fabrication complexity; higher installation cost	Transitional mid-depth zone
Pile/Alternative Bottom-Fixed Systems	~0.7–1.0 million USD (structure only)	85–125	Varies by seabed condition	Shallow–Intermediate	Highly site-dependent	Potentially low structural cost	Strongly dependent on geotechnical conditions	Site-specific shallow developments
Floating—TLB/TLWT	~1.1–1.4 million USD	150–200	High (Tension System)	Deep (>60 m)	Low (Marginal)	Minimal hull mass; efficient steel use	Mooring system complexity; higher financial risk	Deep-water emerging markets
Floating—Semi-sub/Spar	~4.4–8.8 million USD	170–250	Lower (Port-based assembly)	Deep (>60 m, up to 150+ m)	Very Low/Stable	Technically mature; tow-out assembly	High manufacturing CAPEX; complex mooring	High resource deep-water sites

As demonstrated in **Figure 8** and **Table 20**, jacket foundations are typically used in intermediate water depths of 30–60 m, operating within a moderate cost range, with LCOE around 88.20 USD/MWh and construction costs near $7.8 million per unit. While they enable deployment at greater depths than monopiles, they involve higher fabrication and installation complexity. Beyond 60 m, floating systems become necessary; although they require higher upfront investments of around $12.5 million for structures such as TLB or spar, they maintain a relatively stable LCOE of about 115.30 USD/MWh due to reduced sensitivity to depth, as standardized hulls and mooring systems replace heavy steel requirements. It should also be noted that Myhr et al. [15] provide baseline cost estimates based on 2014 European conditions with 5 MW turbines. More recent studies indicate a more dynamic cost landscape: Maienza et al. [21] show that wind speed has a stronger impact on LCOE than platform type, with SSP designs performing best, while Ojo et al. [13] demonstrate that optimized substructures can reduce costs by 10–20%. Globally, the NREL review [8] reports floating offshore wind LCOE between 117–181 USD/MWh for early-stage projects, consistent with earlier upper estimates but highlighting that further reductions depend on improvements in supply chains, port infrastructure, and turbine scaling [8,13,15,21].

The dashed trend lines in **Figure 7** highlight that cost escalation for fixed-bottom systems accelerates more rapidly with depth than for floating systems, producing an economic crossover corridor between approximately 50–70 m. This crossover is sensitive to local conditions, seabed properties, metocean loading, monsoon-constrained installation windows, and regional vessel costs, so the depth boundary should be treated as a preliminary guide pending site-specific geotechnical and metocean investigations [15,40]. Within this zone, monopiles progressively lose cost efficiency, jackets remain viable but grow more expensive, and floating platforms begin to approach competitiveness. These trends are consistent with the depth ranges summarized in **Table 20** and are strongly influenced by site specific factors such as turbine size, seabed conditions, installation logistics, and financing. The LCOE trends also reflect the amplification effect of capital expenditure composition. With CapEx contributing approximately 67–85% of total life-cycle cost, relatively small increases in foundation or installation costs translate directly into noticeable LCOE separation, particularly in the 40–60 m overlap between monopiles and jackets. For floating systems, although production costs dominate, reduced reliance on heavy offshore lifting partially mitigates installation risk in deeper waters [15,40].

Overall, the combined interpretation confirms that water depth governs technology selection, fixed-bottom foundations exhibit nonlinear cost escalation be-

yond ~40–50 m, floating systems present higher initial CapEx but smoother depth sensitivity, and the economic crossover falls within an indicative range of approximately 50–70 m under the modeling assumptions of the referenced literature [20,31], with the important caveat that this boundary is not grounded in site-specific geotechnical or metocean data and may shift depending on local seabed conditions, weather window constraints, vessel availability, and project financing parameters. For emerging markets, this supports a depth-stratified deployment strategy: monopiles in shallow nearshore waters, jackets across transitional shelves, and floating systems in deep offshore areas supported by financial de-risking measures. Offshore wind development should therefore be framed as a depth-dependent economic optimization problem, integrating structural feasibility, installation complexity, and financing conditions within a life-cycle cost framework.

Structural reliability must be considered alongside cost metrics in any credible LCC assessment, yet it remains consistently underweighted in practice. Tropical offshore environments impose a distinct loading profile combining wind thrust, wave-induced fatigue, and warm-water corrosion that diverges from North Sea conditions, potentially trimming monopile service life by 10–15% if site-specific sea states are unmodeled. A common vulnerability across foundation types is poorly constrained soil–structure interaction, making comprehensive ground investigations—including CPT and piezocone testing a necessary investment rather than an optional pre-development activity. This structural imperative is amplified in cyclone-prone regions like Bangladesh, where extreme gusts exceeding 70 m/s necessitate designs beyond standard IEC 61400-1 requirements [33]. Ultimately, this divergence in acute weather risks underscores that a single turbine design cannot serve all tropical settings, making ground investigations and localized load data non-negotiable budget items [33].

In addition to water depth constraints, wind resource characteristics play a decisive role in determining optimal turbine configuration in tropical offshore environments. The studied regions exhibit relatively low wind speeds (5.6–6.9 m/s), significantly below typical North Sea conditions (9–10 m/s), which critically affects energy production due to the cubic dependence of power on wind velocity. A reduction from 10 m/s to approximately 7 m/s can lead to energy losses exceeding 60%, thereby increasing the relative weight of capital expenditure in LCOE. Parametric comparison based on turbine scaling indicates that increasing capacity from 5 MW to 20 MW raises capital costs by approximately 7.5 times, while energy output increases only fourfold, resulting in higher specific costs (from ~$1.2M/MW to ~$2.2M/MW). As illustrated in **Figure 9**, LCOE remains consistently higher for larger turbines under wind speeds below ~7 m/s, indicating diminishing economic returns in low-wind regimes. These findings highlight the existence of a practical threshold where turbine upscaling becomes economically inefficient, suggesting that optimal offshore wind design in emerging markets must simultaneously account for both bathymetric constraints and wind resource limitations rather than relying on global scaling trends.

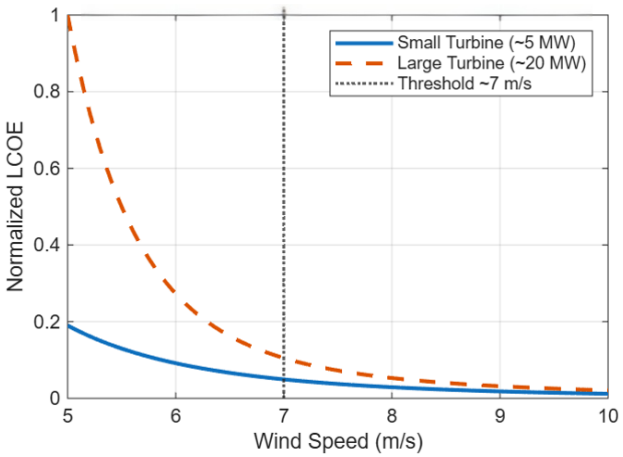

Figure 9. LCOE Sensitivity under Different Turbine Scales.

Despite the divergence in climate risk profiles, a shared technological and governance pathway emerges across Indonesia and Bangladesh. Both nations' reviews converge on the necessity of advanced anti-corrosion and anti-humidity solutions. Marine-grade ISO 12944 C5-M coatings and hydrophobic graphene-enhanced epoxies, recommended for Indonesia's humid environment, are equally essential for Bangladesh to combat saline air and high humidity [33]. In terms of governance, the fragmented regulatory landscape in Indonesia is

mirrored in Bangladesh's institutional structure. Abir and Hossain [33] explicitly propose the establishment of a "National Offshore Wind Energy Authority" to centralize licensing, environmental assessment, and grid integration, a model that directly addresses Indonesia's need for streamlined coordination. These parallels reinforce that institutional consolidation and context-adapted materials are cross-cutting enablers for offshore wind in emerging tropical economies [33].

These comparative insights reaffirm a central theme of this review: the ineffectiveness of a one-size-fits-all approach. While Indonesia's low wind regime favors maximized rotor diameters to achieve high capacity factors, cyclone-prone markets like Bangladesh must prioritize structural robustness, potentially accepting a slightly smaller, more resilient turbine. The contrasting yet converging analysis from both countries solidifies the conclusion that strategic, site specific adaptation encompassing technology, materials, and finance is the only viable pathway for offshore wind development in emerging tropical economies [33].

While this review prioritizes established cost drivers specifically financing structures, turbine layout, and logistical implementation—nascent digital innovations offer further avenues for optimizing the offshore wind lifecycle. Contemporary progress in data-driven methodologies, notably the convergence of artificial intelligence and digital twin frameworks, exhibits significant promise for refining real-time system surveillance, predictive maintenance protocols, and operational scheduling. Research by Lyu et al. [39] indicates that leveraging machine learning, surrogate modeling, and multi-source data fusion can alleviate chronic data constraints such as class imbalance, distribution shifts, and data sparsity hurdles that are particularly acute in emerging markets lacking extensive operational records. Embedding these intelligent architectures into life-cycle cost assessments by synthesizing SCADA outputs, environmental sensing, and simulation-heavy digital twins can diminish forecasting uncertainty and facilitate more responsive project oversight. Although these technologies do not replace the fundamental techno-economic variables discussed herein, they serve as a secondary mechanism to bolster the robustness and performance of offshore wind installations in tropical environments. In a related vein, Hou and Liu [45] establish that the precision of power system datasets remains vital for dependable energy administration: their composite machine learning model—integrating random forest, Spearman-weighted k-nearest neighbors, and Levenberg–Marquardt backpropagation—lowers missing load data imputation errors by 8–38% when accounting for meteorological and temporal variables, highlighting how high-fidelity operational data is essential for rigorous life-cycle cost modeling and maintenance projections for offshore wind assets in data-poor emerging markets [39].

Beyond the scope of digital optimization, the co-development of green hydrogen production provides a significant value-enhancement opportunity, particularly in regions characterized by strong wind resources but constrained grid export capacity. Under such conditions, allocating a portion of generated offshore wind electricity to electrolysis enables surplus or curtailed energy to be converted into a storable and transportable energy vector. Recent feasibility analyses conducted in resource-limited coastal settings report that wind-to-hydrogen configurations can achieve levelized hydrogen production costs in the range of 4.8–5.2 USD/kg under favorable wind regimes, with further cost reductions anticipated as electrolyzer technologies continue to mature and capital expenditures decline [37]. For projects in emerging markets, hydrogen integration has the potential to strengthen overall project viability through revenue diversification while facilitating participation in the expanding global hydrogen economy. This strategy is particularly applicable to remote island systems or regions where grid expansion remains economically prohibitive, thereby aligning with the site-specific adaptation principles emphasized throughout this review [37].

From a forward-looking perspective, offshore wind development can be positioned as a foundational component within multi-stage pathways toward net-zero emissions. Within a phased implementation framework such as the four-stage progression outlined in this review, hydrogen integration would logically occur during an advanced deployment phase (e.g., Phase

4), when local supply chains, port infrastructure, and grid networks have achieved sufficient maturity. At this stage, large-scale electrolysis facilities could contribute not only to domestic decarbonization objectives but also to regional hydrogen export markets. The Gaza Strip case study demonstrates that, even under politically constrained circumstances, wind-powered hydrogen systems can simultaneously alleviate electricity shortages and supply low-carbon transportation fuels, highlighting the operational flexibility of integrated energy solutions [37]. Consequently, for emerging Southeast Asian economies facing increasing energy security concerns alongside strengthened climate commitments, offshore wind hydrogen integration represents a practical pathway for reconciling economic development with long-term sustainability objectives [37].

To operationalize this need for site-specific adaptation, a structured decision framework is required. Drawing on the cost evidence synthesized across the discussion, this section proposes a structured decision framework for selecting offshore wind turbines appropriate to specific site conditions in emerging markets. The framework integrates four primary site parameters: water depth, mean wind speed, distance from port, and grid connection cost, to guide turbine configuration selection across three characteristic deployment scenarios.

Scenario A shallow nearshore sites (≤35 m depth, 5–6 m/s wind), medium sized turbines (3–5 MW) with low specific power (≤250 W/m^2) on monopile foundations are most suitable, as maximizing capacity factor is more important than minimizing upfront cost; studies show such configurations can reach around 39%, supporting viability, though additional logistics costs of USD 3–8 million may arise where port access is limited [48].

Scenario B in intermediate depths (35–60 m, 6–7.5 m/s), jacket or tripod foundations combined with 5–8 MW turbines are preferred, where larger units reduce overall costs through installation and cabling efficiencies, but vessel availability and seasonal weather constraints must be considered [22,29].

Scenario C depths beyond 60 m, floating systems become the practical option, with semisubmersible platforms and 8–10 MW turbines offering strong performance when capacity factors exceed 35% [12,19], although this depth threshold should be treated as a preliminary guide pending site-specific surveys. In these deeper settings, reducing financing risk through long-term fixed-price PPAs backed by government guarantees and supported by concessional funding can significantly lower overall project costs, with potential reductions in energy costs of 25–35% by improving capital conditions [12,19,22,29,48].

5. Conclusions

Grounded in a synthesis of literature and technical documents, this investigation confirms that offshore wind viability in emerging markets particularly Indonesia depends on the strategic integration of financial frameworks, adapted technology, and logistics management. With CapEx comprising 75–85% of LCoE, the Weighted Average Cost of Capital (WACC) is the primary determinant of project feasibility. Achieving a viable WACC requires specific policy mechanisms: (i) long-term, government-backed PPA or CfD structures; (ii) blended finance utilizing MDB concessional debt to bring weighted costs to the 4–6% range; (iii) sovereign green sukuk or bond issuances; and (iv) currency de-risking guarantees through Bank Indonesia or the Ministry of Finance to eliminate foreign exchange premiums. These conclusions are further validated by parallel studies in Bangladesh, which underscore the necessity of government-backed policies and adapted material solutions for tropical marine settings [33].

Indonesia's offshore wind resources are spatially heterogeneous, with average coastal wind speeds of 5–7 m/s lower than typical North Sea conditions, yet this reflects regional averages rather than site-specific potential. Evidence from Papua shows that turbines optimized for low specific power can achieve capacity factors of up to 39%, indicating that performance limitations arise primarily from design mismatch rather than inadequate resources. From a construction standpoint, cost efficiency in tropical waters depends largely on execution speed and logistical planning, where installation strategies using self-propelled vessels and pre-as-

sembly approaches that reduce offshore working time are more effective in overcoming limited weather windows than measures focused solely on lowering vessel charter costs.

This study concludes that offshore wind viability in emerging markets depends on aligning financial risk-mitigation policies with technologies adapted to local wind conditions rather than relying solely on global turbine upscaling trends. Without targeted financial support and design optimization for regional wind regimes, increases in turbine size and technical efficiency alone cannot ensure competitiveness. Supporting this perspective, Hassan et al. [26] show that continued single-rotor scaling faces LCoE stagnation due to super-quadratic mass growth in blades exceeding 100 m, making oversized turbines economically unfavorable in low-wind and logistically constrained regions such as Indonesia and Malaysia. Their findings, which note inconsistent and weakly evidenced LCoE benefits from large turbines, reinforce the prioritization of financial de-risking over capacity expansion in emerging offshore wind markets [29].

This review finds that offshore wind deployment in emerging markets is conditionally viable, succeeding only when specific requirements are met: (1) WACC reduced to 6–8% through government-backed offtake agreements or concessional MDB financing; (2) turbine designs aligned with local wind regimes using low specific power configurations (≤250 W/m^2) capable of achieving 35–39% capacity factors; (3) installation strategies adapted to monsoon constraints through pre-assembly methods that limit offshore exposure; and (4) foundation selection matched to bathymetry, with monopiles suitable to 35 m, jackets to 60 m, and floating systems beyond. Under these combined conditions, feasible in favorable locations such as Papua, coastal Sulawesi, and parts of the Java Sea, LCOE can reach 9–14 ¢/kWh, competitive with national tariffs; however, deviation from any condition, particularly WACC above 10% or unsuitable turbine imports, renders projects economically unviable. Turbine selection must therefore be treated as a system-level supply chain decision, since larger rotors require port upgrades, specialized transport, and appropriate installation vessels, with benefits diminishing where infrastructure or weather windows are limited. Accordingly, this review prioritizes verified cost drivers, financing structure, logistics efficiency, and turbine configuration while treating advanced material innovations discussed in Pradana et al. [30] and Ashuri et al. [35] as prospective rather than confirmed contributors to cost reduction [35,41].

This literature review serves as a structured reference for stakeholders in formulating strategies, making investment decisions, and developing evidence-based policies. The recommendations set out here are grounded in empirical cost evidence and are directly applicable to Indonesia's offshore wind pipeline as it currently stands. Offshore wind in Indonesia is not simply "challenging but achievable," it is commercially viable today at specific sites under specific financing structures, and commercially unviable everywhere else until those structures are established. The distinction matters for policy: the priority is not to make offshore wind generically possible in Indonesia, but to implement the four enabling conditions—offtake certainty, concessional capital, matched turbine configuration, and adapted logistics at selected pioneer sites that can demonstrate bankable economics and create the supply chain foundations on which broader deployment can follow.

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Conflicts of Interest

The authors declare no conflict of interest.

AI Use Statement

During the preparation of this work, the authors used ChatGPT (OpenAI) for grammar checking, sentence structure refinement, and improving the readability of the English text. The authors subsequently reviewed and edited the content as necessary and take full responsibility for the final content of the published article.

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