Reassessing the Economic Viability of the Isle of Man Earystane Onshore Wind Farm

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A Quick Reality Check For Isle Of Man Residents

You may have already had experience of project costs escalating on previous projects - this is my attempt to explain how history is about to repeat itself at your expense.

Abstract

The Earystane (Cair Vie) onshore wind farm, proposed by Manx Utilities, targets a 64% load factor and 30-year lifespan to support the Isle of Man's net-zero goal by 2030. This paper reevaluates viability using realistic assumptions: a 40% load factor, 15-year lifespan, 3% annual degradation, and remote island premiums (+15% capex, +50% O&M). Intermittency and grid balancing costs, including inefficiencies from cycling the island's gas station, add £7/MWh, while grid-scale inverters for high-wind/low-demand periods add £2/MWh. Decommissioning costs, informed by recent Finnish research, add £3–£4/MWh. The levelized cost of energy (LCOE) rises from £35/MWh to £112–£113/MWh (+220–223%), highlighting risks of over-optimistic projections for isolated deployments. Manx Utilities' omission of turbine degradation, decommissioning costs, and additional gas station cycling costs due to wind intermittency suggests a plan driven by ideology rather than sound empirical principles, risking further cost escalations for residents. Calculations use a 5% discount rate and escalation models from Professor Gordon Hughes and others.

1 Introduction

The Isle of Man, a self-governing British Crown Dependency in the Irish Sea, aims for net-zero emissions by 2030 through renewables-led electrification. Manx Utilities' £40 million Earystane wind farm (26 MW) targets this, leveraging high winds for a projected 64% load factor—far exceeding UK onshore averages of 25–40% for large turbines (>2 MW) (1; 2; 31). This estimate assumes minimal curtailment due to the island's isolated grid (3). Notably, the 64% load factor would represent a world record for turbines of this size (likely 4–5 MW), far surpassing even the exceptional 50–52% achieved by Burradale Wind Farm, which uses smaller, simpler, and more reliable 680 kW turbines with longer lifespans (4). Burradale's high load factors and extended operational life are attributable to its small turbine size and robust, less complex technology, contrasting sharply with the larger, more degradation-prone turbines proposed for Earystane (4; 5; 31; 32). Furthermore, the Isle of Man's projections omit critical factors such as turbine degradation, which UK and Danish data show can reduce output by 30% or more over 15 years for >2 MW turbines (5; 6; 31), decommissioning costs, and the additional costs of cycling the island's gas station to manage wind intermittency, pointing to ideological optimism over rigorous, evidence-based planning (3; 29; 16). These omissions reflect wishful thinking rather than the serious, professional planning required for such a significant public investment, risking cost overruns reminiscent of past projects.

Global onshore peaks for large turbines rarely exceed 50–60% (10), and UK data, including a 2024 Nesta report on declining UK onshore wind load factors, confirms degradation (3–4.5% yearly for >2 MW turbines) shortens economic life to 15 years (5; 6; 31). The Nesta report provides measured evidence of load factor declines, reinforcing Hughes' findings with real-world UK wind farm data (31). The latest National Energy System Operator (NESO) report from July 2025 further underscores this trend, reporting a lowering of the average onshore wind load factor compared to 2024 figures, with the 5-year rolling average (based on 2020–2024 data) dropping to 31.3% for all wind (onshore and offshore combined), and specific onshore metrics aligning with DESNZ's downward revisions to 36% for new builds (>5 MW) (32). Remote logistics add premiums, as seen in Shetland/Orkney (7). Wind intermittency requires backup cycling of the gas station, reducing efficiency and adding costs, alongside balancing reserves and grid-scale inverters during high penetration (16; 18). This study quantifies LCOE impacts, comparing to Whitelee (20% load factor) and Walney (43% offshore) (8; 9), emphasizing small-island challenges for residents and the risk of repeating past project cost overruns.

2 Methods and Data Sources

2.1 Key Assumptions

- **Capacity and Costs**: 26 MW, £40 million capex (£1.54 million/MW, +15% to £46 million for logistics), O&M £69,300/MW/year (+50% to £103,950), escalating 2.8%/year (5). Subsidy-free post-15 years (£50/MWh).
- **Load Factor**: Base 64% (149 GWh/year); realistic 40% (93 GWh/year) (3; 10; 31; 32).
- **Lifespan and Degradation**: 15 years, 3% annual output decline (Hughes, Nesta, >2 MW) (5; 31).
- **Intermittency and Balancing**: £7/MWh for backup cycling of gas station, CCGT inefficiencies, reserves (16; 10; 14).
- **Inverters**: £15 million capex (15 MW system for inertia), £0.75 million/year O&M (2.8%/year), adding £2/MWh (26; 27; 28).

- **Decommissioning**: £4.25–£5.1 million base, +50% island premium to £6.4–£7.65 million, adding £3–£4/MWh (29).

- **LCOE Formula**:
$$\text{LCOE} = \frac{\sum_{t=0}^{N} \frac{I_t+M_t}{(1+r)^t}}{\sum_{t=1}^{N} \frac{E_t}{(1+r)^t}}$$
Where I_t = capex, M_t = O&M, F_t = fuel/fixed (0), E_t = annual energy (degraded), r = 5% discount, N = lifespan (12).

2.2 Data Sources

Hughes (2012, 2020, 2021) (5; 6; 13), Manx Utilities (2023–2025) (1; 3), REF/Energy Numbers (8; 9), IRENA/UK DESNZ (10; 2), Shetland reports (7), UK intermittency studies (16; 18; 10), NREL/ESO/DNV for inverters (26; 27; 28), Finnish Wind Power Association (2025) (29), Nesta (2024) (31), NESO/DESNZ (2025) (32). Simulations via Python discounted cash flow.

3 Results

3.1 Load Factors

Earystane's 64% load factor is ambitious and would set a world record for large turbines (4–5 MW), far exceeding the 50–52% achieved by Burradale, which benefits from smaller, simpler, and more reliable 680 kW turbines with longer lifespans (4). A realistic 40% aligns with top UK sites for larger turbines and Nesta's measured UK onshore averages (25–40%) (4; 31). The July 2025 NESO report confirms ongoing declines, with onshore load factors for >2 MW turbines showing further reduction even since the 2024 report, based on updated 2020–2024 data (32). Whitelee averages 20%, Walney 43% (8; 9).

Table 1: Load Factor Comparison

Farm	Type	Lifetime Load Factor	Peak Annual	Notes
Whitelee	Onshore	20% (constrained)	25% (2015)	Curtailment reduces by 5–10% (8)
Walney	Offshore	43%	60% (monthly)	Minimal degradation first 5 years (9)
Burradale	Onshore	50–52%	57.9% (2005)	Small 680 kW turbines; Shetland winds (4)
Earystane	Onshore	64% (base) / 40%	N/A	Island site; no curtailment (3; 31; 32)

3.2 Degradation and Lifespan

Hughes and Nesta report 3% annual degradation for onshore >2 MW turbines, halving output by 15 years (5; 31). Offshore: 2.8–4.5% (6; 13). Nesta's 2024 study, *Declining Performance of UK Onshore Wind Farms*, confirms these trends with measured data from 200+ UK sites with >2 MW turbines, showing load factors dropping from 30–40% to 20–25% over 10–15 years (31). The NESO July 2025 report reinforces this, noting a lowering of average load factors since 2024 due to aging fleets and operational constraints for larger turbines, with a 10.7% cumulative decline from 2020 (36.3%) to 2024 (32.4%) (32). Smaller turbines (<2 MW), like those at Burradale, exhibit lower degradation (1.6% annually) and longer lifespans (20+ years) due to their simpler design and greater reliability (17).

Table 2: Turbine Degradation and Lifespan

Turbine Size	Region	Annual Degradation	Economic Lifespan
>2 MW Onshore	UK/Denmark	3% relative	15 years (5; 31; 32)
>2 MW Offshore	Denmark	4.5% relative	12–15 years (6)
<2 MW Onshore	UK	1.6% relative	20+ years (17)

3.3 Intermittency and Grid Balancing

The Isle of Man's 100 MW grid faces wind intermittency challenges (20). CCGT ramping at the island's gas station reduces efficiency from 55% to 45%, adding £10–£15/MWh (17; 11; 25). Cycling costs £0.26m/year (26 MW) (14; 21). Large turbines (3–4 at 5–7 MW) cause 7% demand shocks, requiring 6–8 MW reserves (£2m/year) (8; 16; 22; 23). UK balancing costs hit £2.65bn in 2021; IoM adds £2–£5/MWh (16; 18). Mid-range: £7/MWh (16; 14).

3.4 Ancillary Services and Inverters

High-wind/low-demand periods (e.g., nights at 80–100% wind supply) reduce inertia, risking instability (26; 27). A 15 MW inverter system (£15 million capex, £0.75 million/year O&M, 2.8%/year escalation) provides synthetic inertia/FFR, adding £2/MWh (26; 27; 28). Without, curtailment could cut 5–10% output (28).

3.5 Decommissioning Costs

The Earystane projections entirely omit decommissioning costs, turbine degradation, and the additional costs of cycling the island's gas station to manage wind intermittency, a triple oversight that suggests a plan driven by ideological commitment to net-zero rather than sound empirical principles (3; 29; 16). Recent Finnish research provides a sobering basis for decommissioning cost estimation, challenging industry-standard figures of 100,000–200,000 per turbine for basic removal and site restoration (29). A June 2025 study, *Assessment of Decommissioning Costs and Financing Models for Onshore Wind Turbines*, reveals actual costs can escalate to nearly 1 million per turbine when accounting for local conditions such as terrain, soil stability, transportation logistics, and comprehensive site rehabilitation (29). These factors are particularly acute for remote island deployments like Earystane, where access via sea or helicopter amplifies expenses.

Assuming 4–5 MW turbines (common for modern onshore installs), Earystane's 26 MW capacity implies approximately 5–6 turbines. Applying the Finnish upper-bound estimate (1 million/turbine $\approx$ £850,000/turbine at current exchange rates) yields a total decommissioning cost of £4.25–£5.1 million. This represents 10–13% of the base £40 million capex—far exceeding the 2–3% provisions sometimes set aside in mainland projects (30). Remote premiums (+50% for logistics, akin to O&M adjustments) could push this to £6.4–£7.65 million, including blade disposal challenges (non-recyclable composites generating 720,000 tons globally over 20 years) and environmental remediation for peatlands or wildlife habitats (29; 30).

Decommissioning must occur post-15 years without subsidies, potentially funded via escalating consumer tariffs. The Finnish study emphasizes that standardized low estimates ignore site-specific complexities, risking under-provisioning and future bailouts—echoing past Isle of Man overruns (29). This omission by Manx Utilities, combined with ignoring degradation impacts and gas station cycling costs, further undermines the project's credibility, prioritizing green aspirations over fiscal responsibility (3; 16). Integrating decommissioning into LCOE (discounted at 5%) adds £3–£4/MWh, further eroding viability.

Table 3: Decommissioning Cost Estimates

Scenario	Turbines	Base Cost/Turbine (£k)	Total Decom. (£m)	+ Island Premium (£m)	LCOE Add (£/MWh)
Industry Standard	5–6	85–170	0.43–1.0	0.64–1.5	+0.5–1.0
Finnish Realistic	5–6	850	4.25–5.1	6.4–7.65	+3–4

3.6 LCOE Impacts

Base LCOE: £35/MWh. Realistic: £79/MWh (+124%). With premiums: £100/MWh (+186%). Adding intermittency (including gas station cycling): £107/MWh (+206%). With inverters: £109/MWh (+212%). Including decommissioning: £112–£113/MWh (+220–223%).

Table 4: LCOE Scenarios

Scenario	Load Factor	Lifespan	Capex (£m)	O&M (£/MW/yr)	+ Intermittency	+ Inverters	+ Decom. (£/MWh)
Base	64%	30	40	69,300	0	0	0
Realistic (No Premiums)	40%	15	40	69,300	0	0	0
Realistic + Premiums	40%	15	46	103,950	0	0	0

Scenario	Load Factor	Lifespan	Capex (£m)	O&M (£/MW/yr)	+ Intermittency	+ Inverters	+ Decom. (£/MWh)
Realistic + Premiums + Intermittency	40%	15	46	103,950	£7/MWh	0	0
Full Realistic + Inverters	40%	15	61	134,719	£7/MWh	£2/MWh	0
Full Realistic + Inverters + Decom.	40%	15	61	134,719	£7/MWh	£2/MWh	£3–4

3.7 Cost vs. Income Over Time

Crossover year 15.

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Year | Income (£) | Costs (£) | Net (£)
-----|------------|-----------|--------
1-5  | 120,000    | 110,000   | +10,000
6-10 | 90,000     | 140,000   | -50,000
11-15| 60,000     | 170,000   | -110,000
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4 Discussion

The 64% load factor is implausible for large turbines (4–5 MW), as it would exceed even Burradale's record 50–52% achieved with smaller, simpler, and more reliable 680 kW turbines with longer lifespans, and no global data supports such performance for >2 MW turbines (4; 10; 31; 32). At 40%, output falls 38%; degradation cuts 30% by year 15 (5; 31). Premiums (+15% capex, +50% O&M) and intermittency (including gas station cycling, £7/MWh) push LCOE to £107/MWh; inverters add £2/MWh (16; 26). Decommissioning, per Finnish insights, adds £3–£4/MWh, totaling £112–£113/MWh—well above import costs (£60–£80/MWh) (29). Nesta's measured data and the NESO July 2025 report's confirmation of further load factor declines since 2024 (10.7% cumulative from 2020 to 2024) for larger turbines underscore the need for conservative assumptions (31; 32). Manx Utilities' failure to account for degradation, decommissioning, and gas station cycling costs signals a plan rooted in ideological net-zero goals rather than empirical rigor, risking consumer-funded bailouts (3; 29; 16). Compared to imports (£60–£80/MWh), viability falters without subsidies. Limitations: No repowering; EIA (2026) pending (3). Residents face repeating past project cost escalations unless mitigated.

5 Conclusion

Earystane's LCOE triples under realistic assumptions, risking consumer costs. Manx Utilities' omission of turbine degradation, decommissioning costs, and the additional costs of cycling the island's gas station to manage wind intermittency—three major factors critical to any credible financial plan—demonstrates a project driven by ideological commitment to net-zero rather than sound empirical principles. The claimed 64% load factor, unprecedented for large 4–5 MW turbines, would surpass even Burradale's world-record performance with smaller, simpler, and more reliable 680 kW turbines, which also benefit from longer lifespans, and lacks support from global data for >2 MW turbines (4; 5; 31; 32). These oversights, ignoring well-documented degradation trends for larger turbines (10.7% cumulative decline from 2020 to 2024) (5; 31; 32), substantial decommissioning expenses (29), and gas station cycling costs due to intermittency (16), undermine the project's credibility and heighten the risk of significant cost overruns, echoing past Isle of Man project failures. You really should stop and think before proceeding with this. Your change makes no difference to the world, not at all. If your island disappeared, the world would make up the CO2 drop in a matter of a few hours.

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