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Financial viability of distribution-connected utility-scale solar PV in Aotearoa New Zealand: A multi-scenario analysis

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Abstract

Aotearoa New Zealand generates over 85% of its electricity from renewable sources, built on hydro and geothermal foundations whose expansion capacity is now structurally constrained. With domestic natural gas supply in accelerating decline and solar photovoltaic (PV) capacity growing 51% in 2024 alone, utility-scale solar is emerging as a central technology for new generation. Yet no study to date has integrated site-specific generation modelling, generation-weighted nodal price analysis, and multi-scenario discounted cash flow analysis for distribution-connected solar PV at this scale within the domestic wholesale market context, leaving investors without a replicable, granular framework for project-level appraisal. This study addresses that gap by assessing the financial viability of a 5 MW utility-scale solar PV project connected to the Powerco distribution network across three candidate nodes — Masterton, Bunnythorpe, and Hawera — with fixed-tilt and single-axis tracking configurations. A three-stage methodology integrates site-specific energy generation modelling using the System Advisor Model (SAM), generation-weighted nodal price analysis based on half-hourly wholesale market data from the Electricity Market Information platform across three reference years (2021, 2023, and 2025), and a multi-scenario discounted cash flow analysis. All six site–configuration combinations generate positive net present values (NPVs) and internal rates of return (IRRs) exceeding the 7% weighted average cost of capital (WACC) threshold. Hawera emerges as the strongest site (IRR: 10.45%–11.06%; NPV: $3.43M–$4.35M), Masterton as an intermediate option, and Bunnythorpe as the most marginal, with the highest sensitivity to adverse wholesale price and generation outcomes. Single-axis tracking delivers superior financial returns at all three nodes. However, its advantage narrows substantially at sites with high diffuse irradiance fractions. Breakeven power purchase agreement (PPA) prices range from $106.49/MWh to $126.50/MWh — well below prevailing generation-weighted wholesale levels — indicating meaningful contracting margin across all configurations. The results provide a site-specific, replicable framework for investment appraisal in Aotearoa New Zealand's distribution network, with direct implications for technology selection, revenue strategy, and the assessment of solar cannibalization risk as the sector scales rapidly.

Keywords: Solar PV; Nodal pricing; Power purchase agreement; Financial viability; Wholesale electricity market.

1. Introduction

Aotearoa New Zealand's electricity system occupies an unusually strong starting position in the global energy transition. In 2024, 85.5% of electricity was generated from renewable sources, down from 88.1% in 2023 due to exceptionally low hydro inflows, and typically exceeding 80% in most years. This share is built over decades on the foundations of hydro and geothermal generation (MBIE, 2025). Yet this legacy mix is approaching its structural ceiling. Hydroelectric capacity, at over 5,000 MW, already accounts for around half of national generation and is geographically constrained in its further expansion. Geothermal, while reaching a record 8,741 GWh in 2024, is concentrated in the Taupō Volcanic Zone and offers limited additional scale. And domestic natural gas, historically the system's primary dry-year backup, is in accelerating decline. Production fell 20.8% in 2024 to its lowest level since 2011, driven by faster-than-expected field depletion across the Maui, Pohokura, and other major Taranaki fields, with production forecasts indicating this decline will continue in coming years (MBIE, 2025). The gap left by gas cannot be filled by hydro or geothermal alone. New generation capacity is needed, and it needs to be deployable at scale and speed.

It is in this context that utility-scale solar photovoltaics (PV) is emerging as a central candidate. Solar technologies only became economically viable alternatives in Aotearoa New Zealand in the mid-2010s, and with hydro and geothermal already meeting most generation needs, the economic urgency for solar investment was more muted than in fossil-fuel-dominated systems. Wind reached commercial scale earlier, with the country's first wind farms commissioned in the late 1990s. Yet even wind remained secondary relative to the country's dispatchable hydro base. Solar, by extension, was further still down the investment queue. That dynamic is now changing rapidly and measurably. Solar generation increased 62% in 2024 to a record 601 GWh, driven by the commissioning of several utility-scale farms including Kohirā, Naumai, Ruawai, and Rangitaiki, while solar PV capacity grew 51% year-on-year (MBIE, 2025). As of October 2025, there were 288 projects in the generation investment pipeline with a combined capacity of 44.3 GW, and more than half of the 1,415 MW currently under construction — 787 MW — corresponds to solar (Electricity Authority, 2026). Total installed solar capacity is forecast to triple between 2026 and 2031.

This rapid build-out, however, introduces its own risks. Transpower has warned that solar projects make up a disproportionately large share of the forward supply pipeline, and that excessive solar generation during daylight hours risks collapsing spot prices, thereby reducing revenues for future projects and potentially undermining the investment case for further deployment (Transpower, 2025). The question of whether individual projects are financially viable — and under what site, configuration, and revenue conditions — is therefore not merely an academic exercise. It is a practical investment problem with direct implications for the pace and geography of Aotearoa New Zealand's solar transition. Yet no study to date has integrated site-specific generation modelling, generation-weighted nodal price analysis, and multi-scenario discounted cash flow analysis for distribution-connected solar PV at the 5 MW scale within the domestic wholesale market context, leaving investors without a replicable, granular framework for project-level appraisal. Existing national-level forecasts, including the MBIE utility-scale solar forecast and the EECA commercial solar analysis (EECA, 2021; MBIE, 2020), assess viability at an aggregate or commercial scale, but neither integrates half-hourly nodal price exposure with site-specific electricity generation outputs and technology configuration comparisons across candidate distribution network nodes.

1.1. Objective of the paper

This paper addresses this gap through a rigorous, site-specific financial assessment of a 5 MW utility-scale solar PV project across three nodes within the Powerco distribution network: Masterton (Wairarapa), Bunnythorpe (Manawatū), and Hawera (Taranaki). By integrating electricity generation modelling across fixed-tilt and single-axis tracking configurations, generation-weighted nodal price analysis, and multi-scenario discounted cash flow analysis, the paper provides a transparent and replicable framework for evaluating the investment case for distribution-connected solar in Aotearoa New Zealand.

Beyond confirming binary project viability, the paper aims to identify which site and configuration variables most decisively drive financial outcomes in the distribution network context, how financial performance and risk exposure vary across nodes and configurations, and what the results imply for technology selection, revenue strategy, and investment prioritisation at a moment of accelerating solar deployment across Aotearoa New Zealand.

2. Literature review

2.1. Financial assessment of utility-scale solar PV

The financial viability of utility-scale solar PV has been assessed through a range of methodological frameworks, with discounted cash flow (DCF) analysis — producing metrics of net present value (NPV), internal rate of return (IRR), and levelized cost of electricity (LCOE) — representing the dominant approach across both academic and practitioner literature. Ryan et al. (2016) provide a foundational multidisciplinary assessment of utility-scale solar PV in Ireland, combining engineering production cost estimation with financial market analysis. Their study constructs NPV and IRR estimates for a 5 MW ground-mounted project across low, best-guess, and high capital cost scenarios, with discount rates of 6%, 7.5%, and 9%. They demonstrate that solar PV remains unviable for private investors without policy support under conditions of low solar irradiance. Although the capital cost context has changed dramatically since then — with global utility-scale CAPEX falling by approximately 75% between 2010 and 2023 (Bolinger et al., 2024) — the methodological structure of their analysis, integrating hourly energy yield modelling with wholesale electricity price exposure to derive breakeven tariff requirements, remains the closest academic precedent in the peer-reviewed literature for this type of project-level appraisal. Both the NPV and IRR metrics serve as the primary investment decision criteria, with LCOE treated as a secondary diagnostic metric useful for cross-configuration comparisons.

Benalcazar et al. (2024) extend the LCOE framework to a spatially explicit analysis of utility-scale PV systems across Poland, decomposing capital expenditure into hardware, soft cost, and installation components. They demonstrate that country-specific cost elements — particularly labour-related installation costs — generate meaningful spatial variation in project economics even when solar irradiance differences are modest. Their findings reinforce the importance of locally grounded cost benchmarks rather than international averages. The role of WACC and capital structure in determining LCOE is examined in detail by Jadidi et al. (2025). They modelled risk mitigation instruments for a 10 MW solar PV project under project finance and demonstrate that WACC is a fundamental determinant of project feasibility: as leverage ratios increase, WACC declines and LCOE improves, but default probability rises. Their sensitivity analysis shows that maintaining a minimum PPA price threshold is essential for bankability at higher leverage ratios.

Within Aotearoa New Zealand, the national-level economic assessment by MBIE (2020) remains the most comprehensive treatment of utility-scale solar viability. The MBIE model integrates solar resource data, capital cost assumptions, and a locational price framework based on nodal wholesale prices weighted by the solar generation profile to determine suitable rates of return across potential sites throughout the country. Its sensitivity analysis identifies reference node price, location factor, and capacity factor as the three equally dominant drivers of NPV — a result that follows directly from the multiplicative structure of revenue (revenue = capacity × capacity factor × reference node price × location factor), so that equal proportional changes in any of these three variables produce identical NPV impacts. Capital cost ranks as the next most sensitive parameter, followed by discount rate. The EECA (2021) commercial-scale analysis extends the financial assessment to business-sited systems of 10 kW to 1 MW across 144 sites in eight centres, finding IRRs ranging from 0.4% to 8.6% and confirming capital cost as the primary sensitivity driver at this scale. While the EECA (2021) study focuses on on-site self-consumption economics rather than wholesale market exposure, its CAPEX benchmark of NZD 1,870/kW for commercial-scale systems provides a useful reference point for utility-scale cost comparisons. The agrivoltaic analysis by Brent et al. (2023) for sheep-and-beef and dairy farms in Canterbury adds further Aotearoa New Zealand-specific cost evidence, reporting CAPEX values of NZD 2,200–2,278/kW for both fixed-tilt and single-axis tracking configurations. These values are higher than utility-scale benchmarks due to additional structural requirements, but the paired fixed-tilt and tracker cost data are informative for understanding the order of magnitude of the tracking cost premium in local conditions.

2.2. Generation-weighted prices and the temporal value of solar

The revenue that a solar generator earns in a wholesale electricity market is not determined by average electricity prices, but by the subset of prices that coincide with its generation profile. This distinction — between the time-averaged wholesale price and the generation-weighted average price received by a solar plant — is foundational to the financial analysis of variable renewable generators and underpins the concept of the market value factor developed by Hirth (2013). The value factor is formally defined as the ratio of the generation-weighted average price to the time-weighted average price, and its magnitude captures how favourably or unfavourably the temporal distribution of a technology's output aligns with the intra-day and seasonal price structure of the market. At low solar penetration, the solar value factor typically exceeds unity in markets where daytime prices are above average — a correlation effect driven by the alignment of solar generation with periods of high demand. Hirth (2013) reports a solar value factor of approximately 1.1 in Germany in 2011, when solar penetration was low and midday prices still reflected peak demand patterns.

The generation-weighted price methodology has been operationalised in the Aotearoa New Zealand context by MBIE (2020), which derives solar-weighted location factors by weighting each half-hourly nodal price by the corresponding normalised solar generation profile, thereby capturing only the revenue-relevant trading periods when the plant is generating. This approach is conceptually equivalent to the generation-weighted nodal price methodology employed in this paper. The EECA (2021) commercial-scale analysis applies the same principle at the level of retail pricing, using 2014–2019 half-hourly average wholesale prices at each centre's grid exit point to construct time-differentiated price profiles that reflect the actual intra-day and seasonal price structure faced by solar generators. Both the MBIE (2020) and EECA (2021) frameworks confirm that the choice of price year materially affects financial outcomes, given the pronounced inter-annual variability in wholesale prices driven by hydrological conditions. EECA (2021) reports mean wholesale prices ranging from approximately NZD 49–78/MWh in the low-price year of 2016 to NZD 109–126/MWh in the high-price year of 2019 across the eight centres analysed. This inter-annual variability, attributable to the country's hydro-dominated generation mix and the sensitivity of wholesale prices to hydro inflows in dry years (MBIE, 2025), is a central challenge for investment appraisal and motivates the three-reference-year averaging approach adopted in the paper.

2.3. The cannibalization effect and solar price risk at scale

As solar penetration increases, the generation-weighted price advantage documented above erodes through the so-called cannibalization effect: the additional supply of zero-marginal-cost solar electricity depresses wholesale prices during peak generation hours, thereby undermining the unit revenues of solar generators themselves. This mechanism is a direct consequence of the merit-order effect — zero-marginal-cost technologies shift the residual supply curve leftward, reducing the marginal clearing price — compounded by the non-dispatchable and temporally concentrated nature of solar output (Hirth, 2013; López Prol et al., 2020). Hirth (2013), drawing on regression analysis of European market data and calibrated modelling of the European electricity market (EMMA), demonstrates that the solar value factor declines below 0.5 at approximately 15% solar market share, a level reached significantly faster for solar than for wind because solar generation is concentrated in fewer hours. The paper identifies the steepness of the merit-order curve, the availability of flexible dispatchable capacity, and the extent of transmission interconnection as the principal drivers of how rapidly the value factor declines with penetration. Critically, Hirth (2013) emphasises that this value decline is not a market failure but an intrinsic consequence of the physical and economic properties of variable renewable energy: as more capacity is installed, each additional MWh is sold at a lower price, and the value of flexibility instruments — storage, demand response, interconnection — increases correspondingly.

López Prol et al. (2020) advance this analysis by jointly quantifying absolute cannibalization (the decline in unit revenues) and relative cannibalization (the decline in value factors) for both solar and wind in California's CAISO wholesale market, using hourly data from January 2013 to June 2017. Their time-series econometric results confirm that solar unit revenues decline by approximately USD 1.295/MWh for each additional percentage point of solar penetration — a larger cannibalization coefficient than the equivalent wind estimate — and that the effect is amplified at low consumption and high penetration levels. The research further identifies a cross-cannibalization dynamic: wind penetration reduces the solar value factor, while solar penetration increases the wind value factor via a shift in the intra-day price structure. Both the absolute and relative cannibalization effects are non-linear, becoming more severe as the solar fleet grows. These findings have direct implications for long-run investment appraisal in Aotearoa New Zealand, where rapid solar deployment — with installed capacity forecast to triple between 2026 and 2031 — is expected to introduce progressive midday price suppression dynamics analogous to those documented in California and Germany. The sensitivity analysis in section 4.4 identifies wholesale price as the structurally more consequential and uncertain risk driver for domestic solar projects, and the cannibalization literature provides the theoretical foundation for treating long-run price trajectories with more caution than historical averages alone would suggest.

2.4. Revenue strategy: PPAs, market hybridisation, and optimal contracting

Against the backdrop of cannibalization risk and wholesale price volatility, power purchase agreements (PPAs) have become the primary revenue security instrument for utility-scale solar projects. Fundamentally, a PPA is a contractual arrangement between a generator and an offtaker to purchase a pre-determined portion of capacity output at a fixed price for a fixed term, decoupling project revenues from the volatile fluctuations of the spot market and providing the revenue certainty required for project finance (Gohdes et al., 2023; Jadidi et al., 2025). Gohdes et al. (2023) examine the optimal level of PPA coverage for utility-scale solar in Australia's National Electricity Market (NEM), developing a dynamic project finance model across four NEM regions. Their results show that a revenue mix of approximately 70–80% PPA coverage with 20–30% merchant spot market exposure is viable and tractable within a project finance capital structure targeting 60–70% debt gearing. Crucially, they demonstrate that increasing PPA coverage beyond this optimal range reduces equity IRR without commensurate improvement in bankability, because the PPA price was set to be competitive — meaning that merchant exposure at the margin allows investors to capture upside from favourable spot prices without being subsidised by an elevated contracted tariff.

Gohdes (2023) contextualises this within the broader phenomenon of energy market hybridisation, whereby governments are re-entering deregulated electricity markets through long-dated PPAs and Contracts-for-Differences (CfDs). The paper argues that these instruments are effectively decoupling long-term investment decisions from short-run spot price dynamics — a "hybridisation" that reduces the exposure of new solar capacity to cannibalization risk during the critical financing period but also introduces policy cost implications that grow as the gap between guaranteed price and declining wholesale revenues widens. The importance of revenue quality for project finance is further reinforced by Jadidi et al. (2025), who show that higher PPA coverage enables greater leverage, lower WACC, and lower LCOE — a feedback loop that makes the PPA not merely a revenue hedge but a capital structure enabler for utility-scale solar projects.

2.5. Technology configuration: Fixed tilt versus single-axis tracking

Single-axis trackers continuously orient the module plane to follow the sun's east–west trajectory, increasing the interception of beam (direct normal) irradiance and thereby improving annual energy yield. However, it comes at the cost of higher capital expenditure, greater mechanical complexity, and elevated operation and maintenance requirements (Elahi Gol and Ščasný, 2023). The magnitude of the yield improvement depends critically on the irradiance composition of the site: tracking delivers its greatest advantage at locations with high direct normal irradiance fractions, while sites dominated by diffuse irradiance realise more modest yield gains (Brent et al., 2023; Elahi Gol and Ščasný, 2023).

Within Aotearoa New Zealand, the MBIE (2020) forecast model assumes a 15% capacity factor improvement from single-axis tracking relative to fixed tilt, describing this as a conservative generalisation for a national-level model while acknowledging that site-specific analyses may yield materially different uplifts. Brent et al. (2023) report tracking uplifts of approximately 17% for a sheep-and-beef agrivoltaic site in Canterbury, noting that tracking systems are more expensive per installed power unit but generate more electricity per panel, and that the relative financial advantage of tracking over fixed tilt is therefore modest when both cost premium and yield gain are considered jointly. The OPEX premium for tracking systems, driven by additional mechanical maintenance requirements, is estimated at approximately 50% over fixed-tilt values in the international literature (Elahi Gol and Ščasný, 2023). An additional consideration is the intra-day price capture advantage of single-axis tracking: by extending generation into the morning and late-afternoon shoulder hours when wholesale prices are elevated, tracking systems achieve a marginally higher generation-weighted captured price relative to fixed-tilt arrays that concentrate output in the lower-priced midday period (Hirth, 2013).

3. Research methods

This research employs a three-stage methodology: (1) solar energy generation modelling using the System Advisor Model (SAM) across three nodes within the Powerco distribution network (Masterton, Bunnythorpe, and Hawera); (2) nodal price analysis using half-hourly wholesale market data from the Electricity Authority's EMI platform;

and (3) multi-scenario financial modelling to assess project viability under wholesale market exposure across six site–configuration combinations.

3.1. Solar generation modelling (SAM)

Energy generation was modelled using the System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL). One candidate site per node zone was modelled, representing the three locations: Masterton (Wairarapa), Bunnythorpe (Manawatū), and Hawera (Taranaki) as shown in Figure 1. Each site was modelled under two system configurations, summarised in Table 1.

Table 1. PV system configurations and key design parameters

Configuration	Tracking	Key parameters
Fixed tilt	None	Tilt = 30°; azimuth = 0° (north); DC/AC ratio = 1.3; GCR = 0.4
Single-axis tracker	N–S axis, E–W rotation	DC/AC ratio = 1.3; GCR = 0.3

SAM inputs included site coordinates, TMY (Typical Meteorological Year) weather data, system capacity consistent with the study's 5 MW project definition (AC), module and inverter specifications, and system losses. Annual energy yield (MWh/yr), monthly generation profiles, and an annual degradation schedule consistent with the financial model horizon (30 years), were exported for use in the financial model.

In SAM, the PVWatts model (simplified performance model) was used to generate an hourly AC generation profile for a representative year. The DC/AC ratio and fixed-tilt angle were selected to maximise simulated annual energy yield for each site, while the ground coverage ratio (GCR) was adopted from the literature.

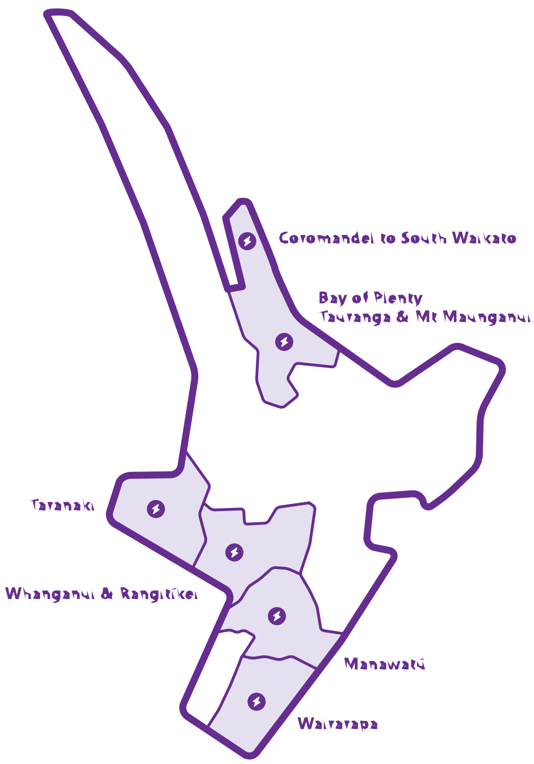

Figure 1. Powerco distribution network coverage area
(Source: Powerco, 2021)

3.2. Nodal price analysis

Half-hourly final nodal prices for the three candidate nodes — Masterton (MST0331), Bunnythorpe (BPE0331), and Hawera (HWA0331) — were obtained from the Electricity Market Information (EMI) platform published by the Electricity Authority for the years 2021, 2023, and 2025 (Electricity Authority, 2026). These three years were selected to capture a range of wholesale market conditions: 2021 was characterised by below-average hydro storage and elevated price volatility, 2023 by lower and flatter prices, and 2025 by more moderate conditions; providing a dataset that spans materially different market regimes over a recent period. All three nodes correspond to 33 kV distribution busbars, consistent with the connection voltage assumed for a 5 MW embedded generation project.

Generation-weighted average prices were calculated by weighting each half-hourly nodal price by the corresponding normalised solar generation profile derived from SAM, thereby capturing only the revenue-relevant trading periods during which the plant was generating. This approach is preferred over simple time-averaged nodal prices because a solar generator's economic exposure is determined by the subset of prices coinciding with its generation profile, not by the full price distribution. The normalised generation profile was derived by dividing the SAM hourly AC output series by its annual sum, producing a set of half-hourly weights summing to unity that reflect the temporal distribution of generation at each site and configuration.

3.3. Financial model

A discounted cash flow model was used to evaluate the economic feasibility of distribution-connected utility-scale solar PV across the candidate nodes (see Figure 2). The model integrates: (i) site-specific annual energy outputs derived from System Advisor Model (SAM) simulations; (ii) revenue assumptions based on generation-weighted nodal wholesale prices derived from Electricity Market Information (EMI) data; and (iii) technology- and scenario-specific cost assumptions, including capital expenditure, operating expenditure, and macroeconomic parameters.

Cash flows were modelled on an annual basis over the project lifetime, with revenues linked to annual AC energy generation and costs escalated where applicable. For each site and system configuration, the model computes pre-tax cash flows (EBITDA) and discounts nominal cash flows using the assumed nominal WACC. Depreciation and corporate income tax were not modelled; accordingly, all reported financial metrics (NPV, IRR, LCOE) are calculated on a pre-tax basis. The base case assumes no curtailment and no on-site self-consumption. In addition to the wholesale revenue scenario, a breakeven PPA tariff is derived for each site–configuration pair as the fixed contracted price at which IRR equals WACC (NPV = 0), serving as a lower-bound reference for PPA contract structuring.

Figure 2. Overview of the financial model structure and data flow

3.3.1. Technical assumptions

Technical assumptions define the plant size, modelling horizon, and the treatment of energy yield over time. Annual AC generation for each site–configuration pair was taken from SAM (PVWatts) outputs and degraded over the project lifetime using the degradation schedule implemented in the Excel model (0.8% in Year 1, followed by 0.5%/year thereafter).

3.3.2. Cost and economic assumptions

Economic assumptions were selected to reflect Aotearoa New Zealand market conditions and standard project-finance practice for utility-scale renewables (see Table 2). All monetary values are expressed in NZD.

Table 2. Economic and cost assumptions adopted in the financial model

Economic/cost parameter	Value	Source/notes
CAPEX (fixed tilt)	1.712 NZD/W	Derived using tracking premium
CAPEX (single-axis tracking)	1.840 NZD/W	MBIE, 2020
OPEX (fixed tilt)	13 NZD/kW-yr	Derived using tracking premium
OPEX (single-axis tracking)	20 NZD/kW-yr	MBIE, 2020
CPI inflation rate	3.10%/yr	Stats NZ, 2026
Wholesale price escalation (PPA escalation)	2.00%/yr	Assumption consistent with long-run real price stability
Nominal discount rate (WACC)	7.00%	IRENA, 2025

3.3.3. Financial metrics and decision criteria

Project performance was assessed using levelized cost of energy (LCOE), net present value (NPV), and internal rate of return (IRR). In addition, a PPA breakeven price was calculated as the contracted tariff required to achieve IRR = WACC (NPV = 0) for each site–configuration case.

3.3.4. CAPEX and OPEX derivation

CAPEX values were compiled from a multi-source review of peer-reviewed studies and Aotearoa New Zealand-focused reports. The reference values by system size and configuration are reported in Table 3.

Table 3. Reference CAPEX values by system size and configuration

Size	Fixed tilt ($/kW)	Tracking ($/kW)	Source
0.72 MW	2,140	2,300	Elahi Gol and Ščasný, 2023
1.0 MW	-	1,870	EECA, 2021
2.0 MW	2,200	2,278	Brent et al., 2023
5.0 MW	1,712*	1,840	MBIE, 2020
10 MW	-	1670	MBIE, 2020
1–200 MW	-	1,610	IRENA, 2025

CAPEX values were compiled from multiple sources to enable a cross-check across different system sizes, technologies, and methodological approaches. The most recent benchmark is provided by IRENA (2025), reporting an average cost of 1,610 NZD/kW. However, this value reflects a weighted average across projects ranging from 1 to 200 MW and therefore does not fully capture scale-specific effects relevant to a 5 MW project. Given the objective of grounding the analysis in Aotearoa New Zealand–specific data, utility-scale benchmarks published by MBIE (2020) were prioritised, providing cost estimates for 5 MW and 10 MW systems.

Consistent with this focus on local benchmarks, an EECA (2021) study reporting a CAPEX of 1,870 NZD/kW for commercial-scale PV systems was also reviewed, illustrating the cost premium associated with smaller project sizes. In addition, higher CAPEX values reported in an agrivoltaics study (Brent et al., 2023), ranging from 2,200 to 2,278 NZD/kW, were considered but not adopted, as agrivoltaic systems involve additional structural and design requirements and are therefore not directly comparable with conventional ground-mounted PV systems.

Finally, as no Aotearoa New Zealand–specific data distinguishing fixed-tilt and single-axis tracking CAPEX were available at utility scale, the relative cost difference reported bythe study of Elahi Gol and Ščasný (2023) was used. A tracking premium of 7.5% was applied to the MBIE tracking benchmark to derive corresponding fixed-tilt CAPEX values, ensuring internal consistency across system configurations.

Elahi Gol and Ščasný (2023) provide paired fixed-tilt and single-axis tracking OPEX values of 10 €/kW yr and 15 €/kW.yr, respectively, implying a 50% cost premium for tracking systems. This ratio is consistent with international literature, where tracking systems typically incur higher maintenance costs due to additional mechanical components and increased inspection requirements.

For Aotearoa New Zealand, the most relevant utility scale OPEX benchmark is provided by MBIE (2020), which reports an annual OPEX of 20 NZD/kW.yr for single-axis tracking systems. As this value is specific to the Aotearoa New Zealand context and reflects local labour, vegetation management, and insurance costs, it is adopted directly for the tracking configuration in this study.

Fixed-tilt OPEX values are not reported in the MBIE study. Therefore, the 50% premium observed by Elahi Gol and Ščasný, (2023) is applied to derive a corresponding fixed-tilt estimate. The adopted OPEX values are: 20 NZD/kW.yr for single-axis tracking (MBIE, 2020) and a calculated value of 13 NZD/kW.yr for the fixed-tilt configuration.

These values fall within the range reported by Brent et al. (2023) and are consistent with the broader international benchmarks summarised by IRENA (2025), which typically report utility scale OPEX values between 12–22 NZD/kW.yr for mature markets.

4. Results and discussion

4.1. Solar generation

Annual energy yield and AC output for each site–configuration pair are summarised in Table 4. Modelled outputs range from 5,961 MWh/yr for Bunnythorpe under fixed-tilt to 7,918 MWh/yr for Hawera under single-axis tracking, representing a spread of approximately 25% between the lowest and highest-performing combinations across the six scenarios evaluated.

Hawera consistently achieves the highest energy yield across both configurations, with fixed-tilt and tracker outputs of 1,368 and 1,584 kWh/kW respectively, reflecting its comparatively lower latitude (−39.6°S) and favourable solar resource within the Taranaki region. Masterton ranks second, with yields of 1,262 and 1,457 kWh/kW under fixed-tilt and tracking respectively, while Bunnythorpe records the lowest outputs of 1,192 and 1,333 kWh/kW. The relatively weaker performance at Bunnythorpe is consistent with the known climatic characteristics of the Manawatū region, which is subject to higher cloud cover frequency and a greater proportion of diffuse irradiance compared to the other two nodes.

Single-axis tracking delivers a generation uplift across all three sites. However, the magnitude of this uplift varies materially by location. Hawera and Masterton record tracking uplifts of 15.8% and 15.5% respectively, while Bunnythorpe achieves a more modest uplift of 11.8%. This divergence is attributable to the diffuse irradiance characteristics of the Manawatū region. Single-axis trackers primarily capture beam (direct normal) irradiance by continuously aligning the module plane perpendicular to the sun's position; under predominantly diffuse conditions, this geometric advantage is diminished, reducing the incremental yield benefit relative to a fixed-tilt array. This finding has direct financial implications, as the lower tracking uplift at Bunnythorpe contributes to a less favourable cost-benefit outcome for the single-axis tracking configuration at that node, as discussed in section 4.3.

Table 4. Annual energy yield and AC energy output by site and system configuration

Site	System	Energy Yield (kWh/kW)	Annual AC Energy (MWh)	Tracking uplift
Masterton	Fixed-tilt	1,262	6,311	+15.5%
	Tracker	1,457	7,286	
Bunnythorpe	Fixed-tilt	1,192	5,961	+11.8%
	Tracker	1,333	6,666	
Hawera	Fixed-tilt	1,368	6,838	+15.8%
	Tracker	1,584	7,918	

The monthly generation profiles derived from SAM outputs, presented in Figure 3, reveal a pronounced seasonal variation common to all six site–configuration combinations. Generation follows a smooth bell-shaped curve characteristic of Southern Hemisphere solar resources, peaking in January and reaching a minimum in June, with a peak-to-trough ratio of approximately 3.5× across all sites.

Two additional features are evident in Figure 3. First, the spread between the highest and lowest-performing site–configuration combinations narrow substantially from summer to winter. In January, a tracker system at Hawera generates 1,050 MWh against 623 MWh from a fixed-tilt system at Bunnythorpe, a spread of 427 MWh. By June this contracts to 134 MWh. This convergence reflects the dominant effect of reduced day length and lower solar elevation angles in winter, which compress generation across all sites regardless of their irradiance characteristics. Second, and notably, single-axis tracking does not uniformly outperform fixed-tilt across all months. During the winter months of May, June, and July, fixed-tilt systems generate more energy than their tracking counterparts at all three sites. This inversion occurs because single-axis trackers derive their advantage primarily from beam (direct normal) irradiance, which is substantially reduced in winter due to lower solar elevation angles and higher diffuse fractions. Under predominantly diffuse winter conditions, the tracker's geometric advantage is diminished. The tracker's annual generation premium over fixed-tilt is concentrated almost entirely in the summer months.

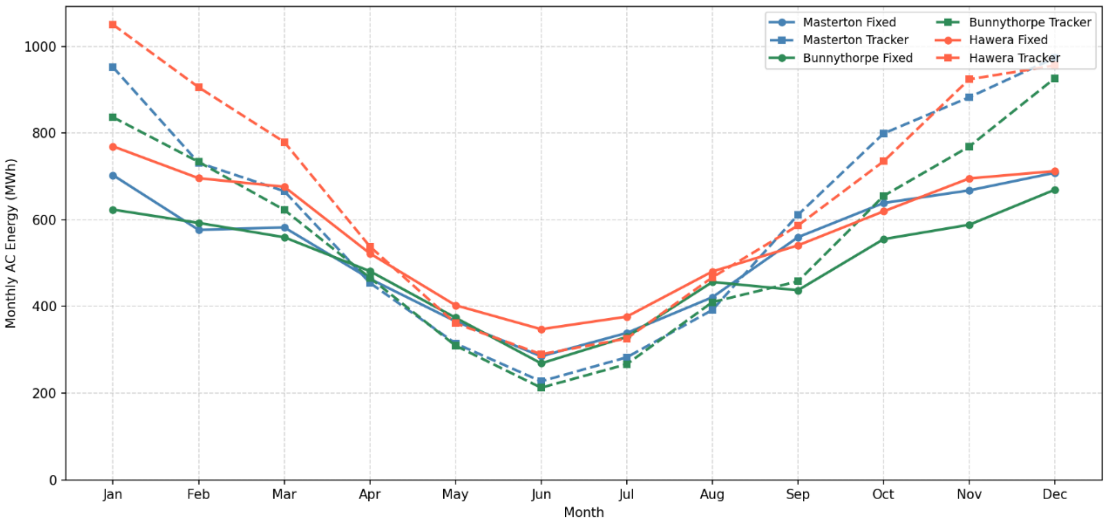

Figure 3. Monthly AC electricity generation

4.2. Nodal price analysis results

Generation-weighted average wholesale prices for each node and system configuration are presented in Table 4. Simple average prices across the three reference years range from $141.93/MWh at Hawera to $146.37/MWh at Masterton, reflecting the spatial structure of nodal pricing within the Powerco network. When weighted by the normalised solar generation profile, captured prices exceed simple averages at all nodes and configurations, indicating that solar generation is, on average, temporally aligned with above-average price periods across the three reference years analysed.

Table 1. Generation-weighted average wholesale prices

Node	Simple Average	GW Fixed	GW Tracker
Masterton	$146.37	$152.39	$153.09
Bunnythorpe	$144.28	$149.99	$150.77
Hawera	$141.93	$147.94	$148.92

Figure 4 presents the monthly average wholesale price and AC generation profiles for each site and configuration across the three reference years, providing a representation of the price-generation relationship. A key observation is that contrary to the archetypal hydro-market narrative in which winter price spikes coincide with minimum solar generation, the relationship between wholesale prices and solar output across the three reference years is broadly co-directional for most of the year. Both prices and generation decline together from January through June and recover together from July through November. The most pronounced misalignment is concentrated in the October to December period, when solar generation rises strongly toward its annual peak while wholesale prices remain at or near their seasonal minimum. It is important to note that this seasonal price pattern may not be fully representative of long-term market conditions.

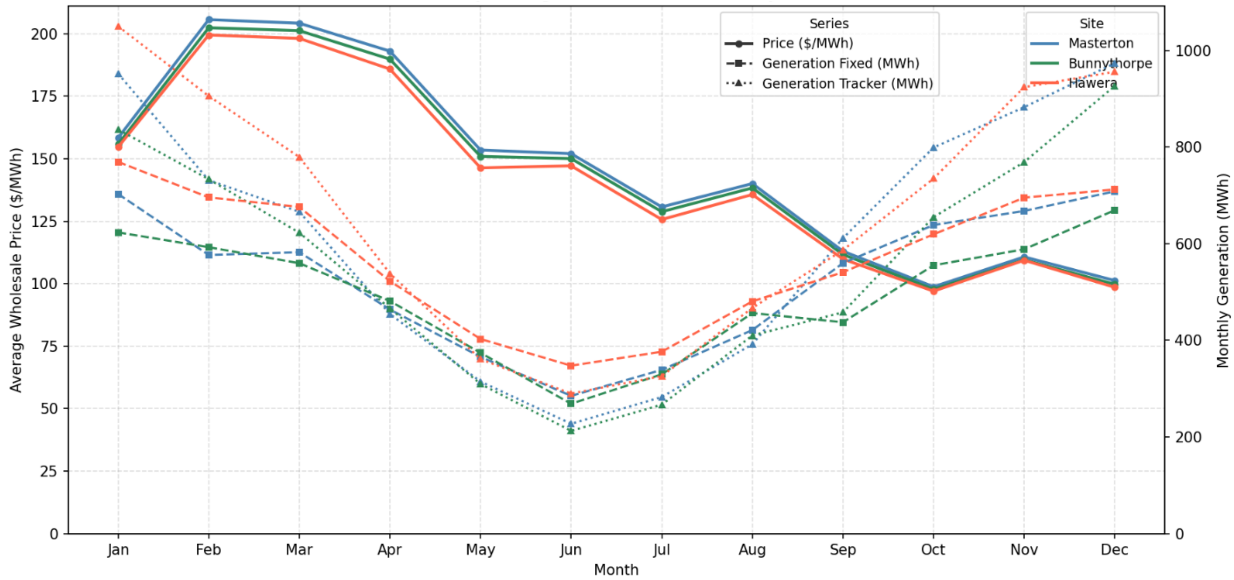

Figure 4. Monthly average price and generation by site

Equally notable is the degree of inter-annual price variability illustrated by the dashed lines in Figure 5, which represent individual reference years while solid lines represent the three-year average. Price dispersion between years is substantial and asymmetric across months, reflecting the sensitivity of wholesale prices to hydrological conditions, with 2021 characterised by below-average hydro storage and elevated price volatility, 2023 by lower and flatter prices, and 2025 by more moderate conditions. The three-year averaging approach adopted in the financial model is therefore not merely a methodological convenience. It is a necessary response to the magnitude of inter-annual price uncertainty faced by solar generators under wholesale market exposure.

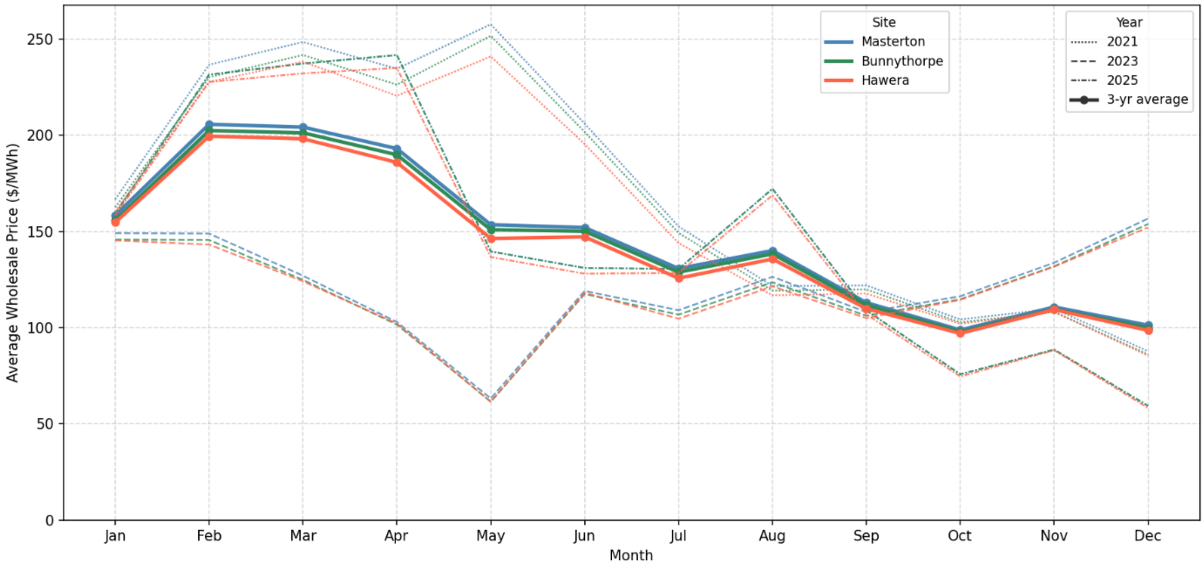

Figure 5. Average monthly wholesale price by node, with three-year average (solid) and individual reference years 2021, 2023 and 2025 (dashed)

A notable finding emerging from Table 4 is that single-axis tracking systems achieve a higher generation-weighted captured price than fixed-tilt systems at all three nodes, with differentials ranging from $0.70/MWh at Masterton to $0.98/MWh at Hawera. This result is consistent with the intra-day price and generation structure illustrated in Figure 6, and reflects two complementary mechanisms through which tracking systems achieve superior price capture relative to fixed-tilt arrays.

Figure 6 overlays the average hourly wholesale price profile against the normalised hourly generation profiles of fixed-tilt and single-axis tracking systems for each node. The wholesale price profile exhibits a characteristic bi-modal shape at all three nodes: prices rise to a morning peak around hours 7–8 (~$150–175/MWh), decline through the central solar hours (hours 9–14, ~$140–155/MWh), and recover strongly to an evening peak around hours 18–19 (~$175–183/MWh).

Within this price environment, single-axis trackers systematically capture a larger share of generation during the higher-priced morning and afternoon shoulder periods relative to fixed-tilt systems. Conversely, fixed-tilt systems concentrate a greater share of their normalised output in the midday hours, when the wholesale prices are at their intra-day minimum. The net effect of these two offsetting shifts is a consistent, if modest, captured price premium for the tracker across all three nodes.

It is important to contextualise the magnitude of this differential. At $0.70–$0.98/MWh, the tracker's captured price advantage is small relative to the absolute level of generation-weighted prices ($148–153/MWh) and is substantially outweighed by the tracker's generation uplift of 11.8–15.8% documented in section 4.1. Consequently, both the generation volume and the captured price favour single-axis tracking, reinforcing its financial superiority across all three nodes — a finding that is elaborated in the financial results presented in section 4.3.

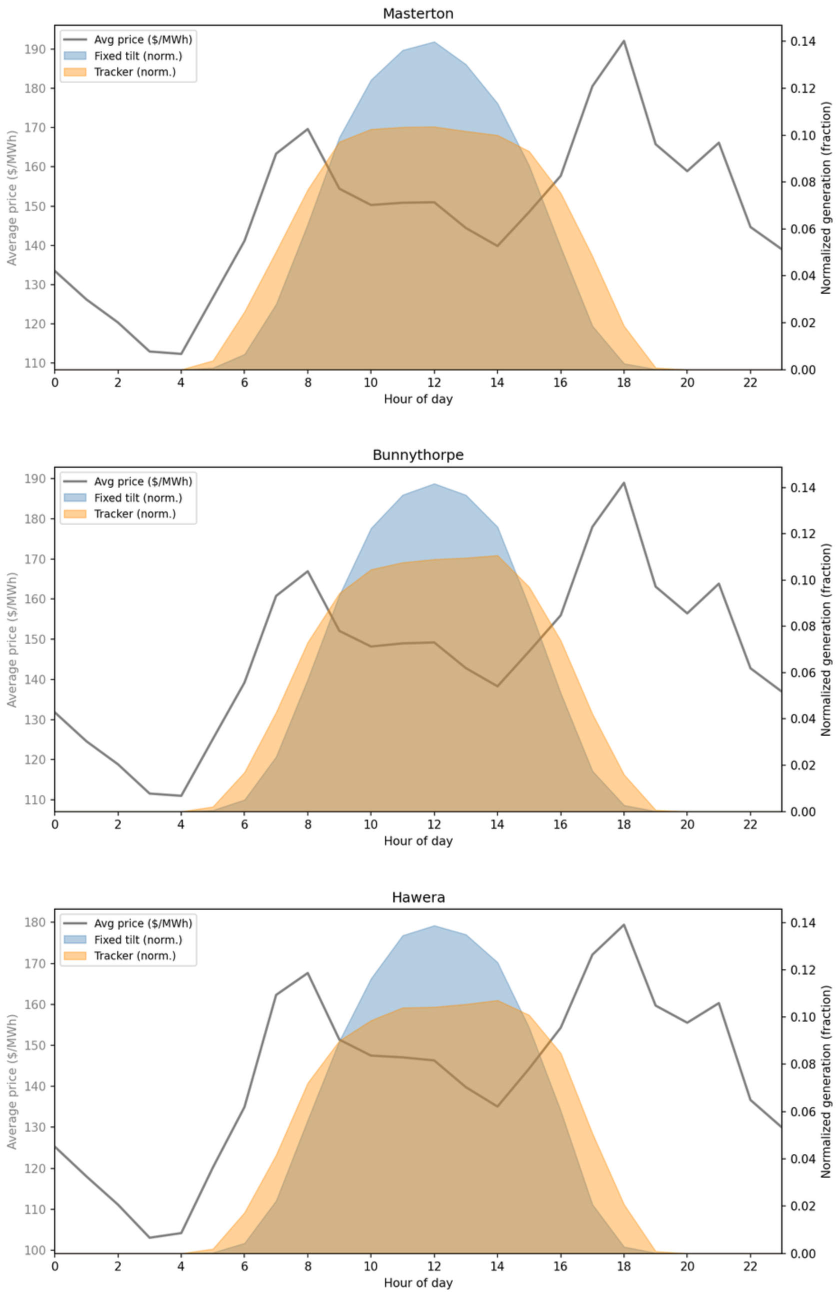

Figure 6. Hourly generation and simple average price by site

4.3. Financial results

The financial results for all six site–configuration combinations are summarised in Table 2. All six scenarios generate positive NPVs and IRRs exceeding the 7% WACC threshold, confirming that utility-scale solar is financially viable across all three nodes and both system configurations evaluated under wholesale market exposure. However, the magnitude of returns varies substantially across sites and configurations, with important implications for investment prioritisation and risk assessment.

Hawera emerges as the strongest site across all financial metrics, recording IRRs of 10.45% and 11.06% and NPVs of $3.43M and $4.07M under fixed-tilt and single-axis tracking respectively. Masterton ranks second with IRRs of 9.83% and 10.33%, while Bunnythorpe records the lowest returns of 8.97% (fixed) and 9.03% (tracker). This site hierarchy is broadly consistent with the generation results established in section 4.1, reflecting the compounding effect of energy yield differences across the project's 30-year life.

Single-axis tracking delivers superior financial returns at all three nodes. This outcome reflects the combined effect of two advantages documented in sections 4.1 and 4.2: tracking systems generate more energy in absolute terms and also achieve a marginally higher generation-weighted captured price due to their broader temporal generation profile across the higher-priced morning and evening shoulder hours. At Masterton and Hawera, the tracker's IRR premium over fixed-tilt is 50 and 61 basis points respectively. At Bunnythorpe, the premium narrows to just 6 basis points; a consequence of the site's lower tracking uplift of 11.8% relative to 15–16% at the other two nodes, which limits the incremental revenue gain despite the tracker's captured price advantage being consistent across all sites. In this marginal case, the additional CAPEX and OPEX of the tracker are only barely justified by the incremental generation gain, reinforcing the importance of site-specific analysis of irradiance characteristics before committing to a technology configuration.

The tracker achieves a lower LCOE than fixed-tilt at all three sites, reflecting its ability to generate sufficient additional energy to dilute its higher cost base. The LCOE differential between configurations is most pronounced at Hawera ($118.01/MWh fixed versus $109.56/MWh tracker), where the tracking uplift is largest.

The breakeven PPA prices presented in Table 2 provide a practical benchmark for revenue contracting decisions. Across all six configurations, breakeven prices range from $106.49/MWh for a tracking system at Hawera to $126.50/MWh for a tracking system at Bunnythorpe; substantially below the generation-weighted wholesale prices of $148–153/MWh observed across all nodes. This gap of approximately $22–47/MWh represents the margin within which a long-term PPA could be structured while still delivering returns above the WACC, and its width varies materially by site and configuration, with Hawera offering the greatest contracting flexibility and Bunnythorpe the least.

A notable exception to the tracker's otherwise consistent financial superiority emerges, however, when breakeven prices are compared within Bunnythorpe. Despite achieving a higher IRR under wholesale exposure (9.03% versus 8.97%), the tracking configuration requires a marginally higher breakeven PPA of $126.50/MWh relative to $125.36/MWh for fixed-tilt; an outcome that reflects the asymmetric cost structure of the two configurations under constrained revenue conditions. At Bunnythorpe, the tracker's incremental generation advantage is the smallest of the three nodes (11.8%), and when the contracted price is reduced to the minimum required to achieve WACC, this modest yield uplift is insufficient to absorb the tracker's higher CAPEX and OPEX relative to fixed-tilt. The result has a direct practical implication: while the tracker is the preferred configuration under wholesale market exposure at all three nodes, the fixed-tilt system at Bunnythorpe offers a lower revenue floor and is therefore more readily bankable under a PPA structure. This finding underscores the importance of evaluating technology configuration not only against expected wholesale returns but also against the minimum contracted price required to satisfy lender requirements.

Table 2. Financial results summary

Site	System	CAPEX ($M)	OPEX ($k/yr)	LCOE ($/MWh)	NPV ($M)	IRR	Breakeven PPA ($/MWh)
Masterton	Fixed	8.56	65	127.88	2.56	9.83%	118.42
	Tracker	9.20	100	119.06	3.30	10.33%	115.73
Bunnythorpe	Fixed	8.56	65	135.38	1.77	8.97%	125.36
	Tracker	9.20	100	130.15	1.96	9.03%	126.50
Hawera	Fixed	8.56	65	118.01	3.20	10.45%	109.28
	Tracker	9.20	100	109.56	4.07	11.06%	106.49

A notable additional finding is the material impact of project scale on financial returns, illustrated in Table 3. Scaling the best-performing configuration — Hawera single-axis tracking — from 5 MW to 10 MW reduces CAPEX from $1.84/W to $1.67/W, a reduction of approximately 9%, reflecting economies of scale in procurement, engineering, and installation. This CAPEX reduction drives a substantial improvement in project economics: the IRR increases from 11.06% to 13.10% — a 204 basis point improvement — while NPV increases from $4.07M to $11.52M, nearly tripling in absolute terms. The generation-weighted captured price also increases marginally at the larger scale ($149.92/MWh versus $148.92/MWh), consistent with the identical tracking uplift of 15.8% across both system sizes and the same nodal price environment. OPEX scales linearly from $100k to $200k per year. These results are consistent with the learning curve dynamics documented for the solar market, where capital cost reductions of comparable magnitude have been identified across increasing system sizes (MBIE, 2020).

Table 3. Scale comparison — Hawera single-axis tracking: 5 MW versus 10 MW

Metric	5 MW	10 MW
Annual AC Energy (MWh)	7,918	15,836
Generation-weighted price ($/MWh)	148.92	149.92
CAPEX ($/W)	1.84	1.67
Total CAPEX ($M)	9.2	16.7
OPEX ($k/yr)	100	200
IRR (%)	11.06	13.10
NPV ($M)	4.07	11.52

4.4. Sensitivity analysis

A one-way sensitivity analysis was performed on the two extreme configurations under wholesale market exposure — the tracking systems at Hawera (base IRR 11.06%) and the fixed-tilt systems at Bunnythorpe (base IRR 8.97%) — to assess the robustness of the base case financial results. Three drivers were stressed independently across a uniform ±20% range: CAPEX, annual generation, and weighted average wholesale price. While a ±20% variation in generation exceeds the typical P90/P10 bounds, where inter-annual variability generally falls within ±10% of the long-run mean. This range was adopted deliberately to ensure methodological comparability across all three drivers and to provide a conservative outer boundary for scenario testing. A two-way sensitivity analysis combining CAPEX and generation variations was subsequently performed for both configurations, using a ±10% generation range consistent with typical P90/P10 bounds, while CAPEX was retained at ±20%. The two analyses therefore serve distinct purposes: the one-way analysis examines the relative sensitivity of IRR to each driver in isolation under a standardised stress range, while the two-way analysis maps the joint IRR outcomes across a plausible combination of cost and resource scenarios.

Table 4, Table ***5*** and Table ***6*** present the one-way results, with tornado charts for each configuration illustrated in Figure 7 and Figure ***8***. A methodologically notable feature of the results is that generation (±20%) and wholesale price (±20%) produce identical IRR impacts at both sites; a consequence of the multiplicative structure of revenue (revenue = price × generation), whereby equal proportional changes in either variable produce the same absolute shift in annual cashflow and therefore the same effect on IRR. At Hawera for the tracking system, both drivers produce a total IRR range of 5.38 pp (8.27% to 13.65%), while CAPEX produces a range of 4.93 pp (9.02% to 13.94%). At Bunnythorpe for the fixed-tilt system, the corresponding ranges are 4.65 pp (6.55% to 11.20%) for generation and price, and 4.32 pp (7.17% to 11.49%) for CAPEX. Although the IRR impact is arithmetically equivalent across generation and price, they represent qualitatively distinct risk categories: wholesale price uncertainty is an exogenous market risk driven by hydrological conditions, demand patterns, and the cannibalisation effect due to the progressive entry of variable renewable generation into the electricity market. On the other hand, generation uncertainty reflects a technical and climatic risk that is partially mitigable through performance guarantees, module warranties, and insurance products. This distinction is consequential for risk allocation between project sponsors and lenders, and for the structuring of appropriate risk mitigation instruments.

The most significant finding from the one-way analysis concerns the downside exposure of the fixed-tilt system at Bunnythorpe under adverse conditions. A 20% reduction in either wholesale price or generation reduces the IRR to 6.55% — below the 7% WACC threshold — rendering the project unfeasible. Similarly, a 20% CAPEX overrun reduces the IRR to 7.17%, leaving a margin of only 17 basis points above the viability threshold. The tracking system at Hawera, by contrast, maintains an IRR of 8.27% under a 20% price or generation reduction, and 9.02% under a 20% CAPEX overrun — comfortably above the WACC in both cases. This confirms that a tracking system at Hawera retains meaningful financial resilience across all individual stress scenarios tested, while a fixed-tilt system at Bunnythorpe is vulnerable to adverse realisation of any single driver.

Table 4. One-way sensitivity: CAPEX

One-way Sensitivity: CAPEX					
CAPEX variation	**-20%**	**-10%**	**Base**	**10%**	**20%**
Multiplier	0.80	0.90	1.00	1.10	1.20
Hawera Tracker — IRR	13.94%	12.36%	11.06%	9.96%	9.02%
Hawera Tracker — NPV ($)	$5,786,717	$4,926,904	$4,067,091	$3,207,278	$2,347,465
Bunnythorpe Fixed — IRR	11.49%	10.11%	8.97%	8.00%	7.17%
Bunnythorpe Fixed — NPV ($)	$3,377,058	$2,577,058	$1,777,058	$977,058	$177,058

Table 5. One-way sensitivity: Generation

One-way Sensitivity: Generation					
Generation variation	**-20%**	**-10%**	**Base**	**10%**	**20%**
Multiplier	0.80	0.90	1.00	1.10	1.20
Hawera Tracker — IRR	8.27%	9.70%	11.06%	12.37%	13.65%
Hawera Tracker — NPV ($)	$1,212,111	$2,639,601	$4,067,091	$5,494,581	$6,922,071
Bunnythorpe Fixed — IRR	6.55%	7.79%	8.97%	10.10%	11.20%
Bunnythorpe Fixed — NPV ($)	-$387,611	$694,724	$1,777,058	$2,859,393	$3,941,728

Table 6. One-way sensitivity: Weighted average wholesale price

One-way Sensitivity: Weighted Average Wholesale Price					
Wholesale Price variation	**-20%**	**-10%**	**Base**	**10%**	**20%**
Multiplier	0.8	0.9	1.0	1.1	1.2
Hawera price ($/MWh)	$119.14	$134.03	$148.92	$163.81	$178.70
Bunnythorpe price ($/MWh)	$119.99	$134.99	$149.99	$164.99	$179.99
Hawera Tracker — IRR	8.27%	9.70%	11.06%	12.37%	13.65%
Hawera Tracker — NPV ($)	$1,212,111	$2,639,601	$4,067,091	$5,494,581	$6,922,071
Bunnythorpe Fixed— IRR	6.55%	7.79%	8.97%	10.10%	11.20%
Bunnythorpe Fixed — NPV ($)	-$387,611	$694,724	$1,777,058	$2,859,393	$3,941,728

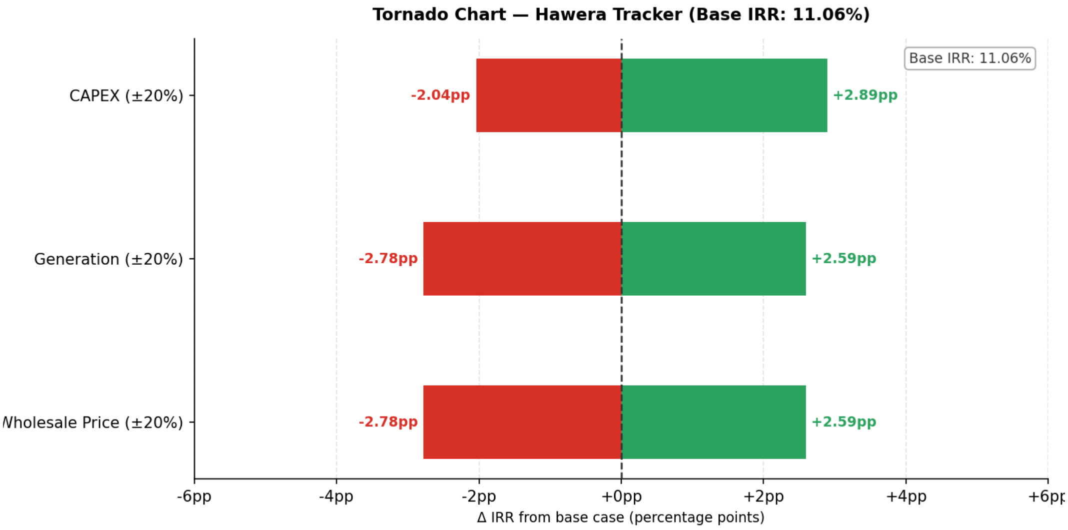

Figure 7. Tornado chart — Hawera single-axis tracking

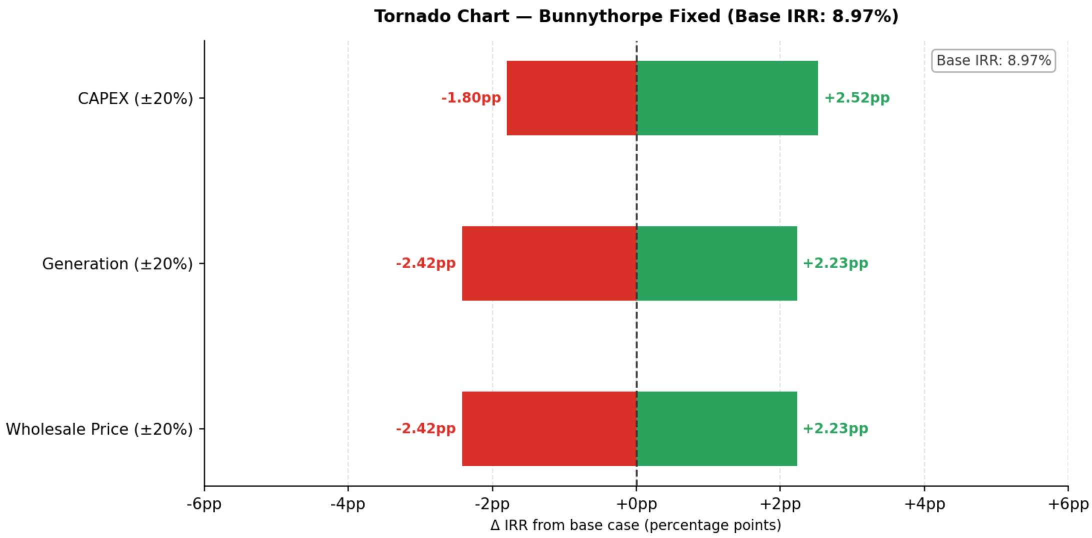

Figure 8. Tornado chart — Bunnythorpe fixed-tilt

The two-way sensitivity analysis — combining CAPEX (±20%) and generation (±10%) stress scenarios — is presented in Tables 10 and 11. For the tracking system at Hawera, no combination within the joint stress space breaches the WACC threshold. Even under the most adverse combination of CAPEX +20% and generation −10%, the IRR remains at 7.81%. The fixed-tilt system at Bunnythorpe, by contrast, breaches the viability threshold across multiple adverse combinations. At base generation, a CAPEX overrun of 20% reduces the IRR to 7.17%; any generation shortfall compounds this outcome, with CAPEX +20% and generation −10% producing an IRR of 6.89% — below the WACC. Even at base CAPEX, a 10% generation shortfall reduces the IRR to 7.79%, leaving a buffer of only 79 basis points above the threshold.

Taken together, the sensitivity results reveal a clear bifurcation in the risk profiles of the two configurations. The trackiong system at Hawera is resilient across the entire joint CAPEX–generation stress space tested, maintaining returns above the WACC under all plausible combinations of cost and resource outcomes. The fixed-tilt system at Bunnythorpe, by contrast, is fragile across a wide range of individually and jointly adverse scenarios, with the WACC threshold breached under single-driver stress in both price and generation, and under moderate combined stress in CAPEX and generation. While generation and wholesale price produce arithmetically equivalent IRR impacts, wholesale price is the structurally more volatile driver, particularly in the Aotearoa New Zealand context, where progressive solar penetration raises the prospect of duck curve dynamics compressing generation-weighted captured prices over the project life. This asymmetry has direct implications for solar projects viability.

Table 7. Two-way sensitivity: CAPEX × Generation — Hawera Tracker — IRR

CAPEX ↓ / Gen →	Gen -10%	Gen -5%	Gen Base	Gen +5%	Gen +10%
CAPEX -20%	12.34%	13.15%	13.94%	14.72%	15.50%
CAPEX -10%	10.89%	11.63%	12.36%	13.07%	13.78%
CAPEX Base	9.70%	10.38%	**11.06%**	11.72%	12.37%
CAPEX +10%	8.68%	9.33%	9.96%	10.58%	11.19%
CAPEX +20%	7.81%	8.42%	9.02%	9.60%	10.18%

Table 8. Two-way sensitivity: CAPEX × Generation — Bunnythorpe Fixed — IRR

CAPEX ↓ / Gen →	Gen -10%	Gen -5%	Gen Base	Gen +5%	Gen +10%
CAPEX -20%	10.12%	10.81%	11.49%	12.15%	12.81%
CAPEX -10%	8.85%	9.49%	10.11%	10.72%	11.33%
CAPEX Base	7.79%	8.39%	**8.97%**	9.54%	10.10%
CAPEX +10%	6.89%	7.45%	8.00%	8.54%	9.07%
CAPEX +20%	6.11%	6.65%	7.17%	7.68%	8.18%

5. Conclusion and Recommendations

This paper assessed the financial viability of a 5 MW utility-scale solar PV project connected to the Powerco distribution network across three candidate nodes — Masterton, Bunnythorpe, and Hawera — under wholesale market exposure, integrating site-specific energy generation modelling, nodal price analysis, and multi-scenario discounted cash flow analysis across fixed-tilt and single-axis tracking configurations.

The results confirm that utility-scale solar PV is financially viable across all six site–configuration combinations evaluated, with all scenarios generating positive NPVs and IRRs exceeding the 7% WACC threshold. Hawera emerges as the strongest site across all financial metrics, driven by its lower latitude, higher irradiance, and favourable nodal price environment, while Masterton occupies an intermediate position and Bunnythorpe records the lowest returns — a consequence of its higher cloud cover frequency, greater diffuse irradiance fraction, and the smallest tracking yield uplift of the three nodes at 11.8%.

Single-axis tracking delivers superior financial returns under wholesale market exposure at all three nodes, reflecting the combined effect of higher energy yield and a marginally higher generation-weighted captured price. The latter finding emerges from the intra-day price structure of the wholesale market: trackers extend generation into the higher-priced morning and late afternoon shoulder periods, while fixed-tilt systems concentrate output in the lower-priced midday hours, producing a consistent captured price premium of $0.70–$0.98/MWh in favour of tracking across all nodes. However, the financial superiority of single-axis tracking is not unconditional. At Bunnythorpe, where the tracking yield uplift is the smallest of the three sites, the incremental revenue gain barely justifies the tracker system's higher CAPEX and OPEX. Also, under a PPA structure, the fixed-tilt configuration actually requires a lower breakeven price ($125.36/MWh versus $126.50/MWh), making it more readily bankable. More broadly, in sites where the tracking uplift is marginal, the case for fixed-tilt is strengthened not only financially but operationally: fixed-tilt systems carry lower mechanical complexity, reduced maintenance requirements, and lower failure risk over a 30-year asset life. These considerations that are relevant to investment decisions beyond IRR alone.

The sensitivity analysis reveals a pronounced bifurcation in the risk profiles of the two extreme configurations. A tracking system at Hawera is resilient across virtually the entire joint CAPEX–generation stress space, maintaining returns above the WACC under all plausible combinations of adverse cost and resource outcomes. A fixed-tilt system at Bunnythorpe, by contrast, breaches the viability threshold under single-driver stress in both wholesale price and generation, and under moderate combined stress in CAPEX and generation. This confirms that not all financially viable configurations carry equivalent risk profiles. Critically, while generation and wholesale price produce arithmetically equivalent IRR impacts under a uniform stress range, wholesale price is the structurally more uncertain and volatile driver. Generation risk at a given site is substantially bounded ex-ante by the historical irradiance record. Wholesale price risk, by contrast, is exposed to structural transformation as solar penetration increases. Progressive solar penetration in the country raises the prospect of duck curve dynamics that could materially compress generation-weighted captured prices over the project life. This risk is not captured in the three-year historical price averages used in the base case model and warrants explicit consideration in long-run investment appraisal. For projects of this scale, a power purchase agreement represents a particularly attractive risk mitigation instrument. The breakeven PPA prices calculated across all six configurations lie substantially below prevailing wholesale levels, providing meaningful contracting margin, and the 5 MW project scale is well suited to absorption by a single commercial or industrial offtaker. This contrasts with utility-scale projects of 100 MW or more, where the volume and revenue complexity of a PPA typically makes wholesale market exposure the preferred, and often only practical, revenue strategy.

Finally, the scale analysis demonstrates that expanding the tracking configuration at Hawera from 5 MW to 10 MW reduces CAPEX from $1.84/W to $1.67/W, improving the IRR from 11.06% to 13.10% and nearly tripling the NPV from $4.35M to $11.52M. These results underscore the sensitivity of project economics to scale and suggest that where network capacity and land constraints permit, larger system sizes warrant serious consideration within the Powerco distribution network.

5.1. Recommendations for investors and project developers

The results of this analysis support a clear site prioritisation framework for utility-scale solar investment within the Powerco distribution network. Hawera represents the most attractive investment opportunity across all metrics evaluated — highest IRR, largest NPV, greatest sensitivity resilience, and widest PPA contracting margin — and should be prioritised accordingly. Masterton offers a viable intermediate option, while Bunnythorpe warrants a more cautious approach given its narrower margin above the WACC threshold and heightened sensitivity to adverse wholesale price and generation outcomes.

Technology selection should not default to single-axis tracking without prior site-specific analysis. While tracking delivers superior returns at all three nodes under wholesale market exposure, the financial advantage narrows substantially at sites with low diffuse irradiance fractions and limited tracking yield uplift. At such sites, the lower CAPEX, reduced OPEX, and lower mechanical complexity of fixed-tilt systems may represent a more appropriate risk-adjusted choice — particularly under a PPA revenue structure, where Bunnythorpe Fixed actually requires a lower breakeven price than its tracking counterpart.

Where network capacity and land constraints permit, project developers should evaluate system sizes beyond 5 MW. The scale analysis presented in section 4.3 demonstrates that expanding to 10 MW at Hawera reduces CAPEX intensity from $1.84/W to $1.67/W, improving IRR from 11.06% to 13.10% and nearly tripling NPV. These economies of scale are material and should be incorporated into feasibility assessments from the outset.

For projects of this scale, a power purchase agreement warrants serious consideration as a primary revenue strategy. The breakeven PPA prices calculated across all six configurations — ranging from $106.49/MWh to $126.50/MWh — lie substantially below prevailing generation-weighted wholesale prices of $148–153/MWh, providing a contracting margin of $22–47/MWh within which a commercially viable PPA can be structured. A 5 MW project is well suited to absorption by a single commercial or industrial offtaker, making PPA execution practically feasible at this scale — in contrast to projects of 100 MW or more, where the volume and revenue complexity of a PPA typically makes wholesale market exposure the only revenue strategy. Given the structural wholesale price risk identified in the sensitivity analysis — and particularly the prospect of solar cannibalization compressing captured prices as renewable penetration increases — locking in a contracted revenue floor represents a prudent risk mitigation strategy for projects of this size.

The integration of battery energy storage systems (BESS) should be evaluated as a complementary investment at the project development stage. The intra-day price dynamics documented in section 4.2 — with pronounced morning and evening price peaks flanking a lower-priced midday period — create a natural economic case for storage. A BESS co-located with a solar PV system could shift midday generation to the higher-priced evening peak, improving generation-weighted captured prices and partially mitigating the duck curve risk identified in the sensitivity analysis. As solar penetration in increases and midday price suppression deepens, the revenue uplift from storage dispatch optimisation is likely to grow, potentially transforming BESS from an optional enhancement to a structural component of viable solar project design.

Investors and developers should also account for the potential impact of future transmission infrastructure upgrades on nodal price dynamics. Current wholesale prices at nodes are partly influenced by grid constraints and the physical distance from South Island hydro generation — conditions that inflate nodal prices and contribute to the financial viability documented in this analysis. Transpower has signalled that transmission upgrades will be required to accommodate increased demand and renewable generation capacity over the coming decades. Such upgrades, if realised, could reduce grid constraints, lower nodal price premiums, and alter the relative attractiveness of candidate sites. Projects that appear financially viable under current network conditions may face materially different economics post-upgrade, and this structural risk should be incorporated into long-run investment appraisal alongside the wholesale price scenarios modelled in this paper.

5.2. Recommendations for policy makers and regulators

The finding that wholesale price uncertainty is the dominant financial risk for distribution-connected solar projects, exceeding CAPEX risk in structural significance, has implications for electricity market design and renewable energy policy in Aotearoa New Zealand. Progressive solar penetration, if unmanaged, risks creating self-defeating market dynamics. As solar generation increases, midday price suppression deepens, reducing the captured price of new solar projects and potentially undermining the investment case for further deployment. The Electricity Authority should consider whether existing market signals are sufficient to coordinate the pace and geographic distribution of solar entry in a manner that preserves adequate price signals for investment.

Demand-side interventions represent a complementary policy lever. Incentivising large electricity consumers, including industrial users, data centres, and electrified transport fleets, to shift consumption toward midday solar generation peaks would support price levels during high-irradiance periods, attenuate duck curve dynamics, and improve the economics of solar investment without requiring direct subsidy. Time-of-use pricing mechanisms, demand response programmes, and targeted industrial electrification incentives could each contribute to this outcome and warrant evaluation as part of Aotearoa New Zealand's broader energy transition policy framework.

5.3. Recommendations for future research

This analysis is grounded in a three-year wholesale price average spanning 2021, 2023, and 2025; a period characterised by substantial inter-annual variability. Future research should develop long-run wholesale price scenarios that explicitly model the trajectory of solar cannibalization under different penetration pathways, incorporating the feedback between solar generation volumes, intra-day price dynamics, and generation-weighted captured prices. Such scenarios would provide a more robust foundation for investment appraisal under energy transition conditions than historical price averages alone.

The analysis should also be extended to a broader set of nodes within the Powerco distribution network, and potentially to other distribution networks across the country, to provide a more comprehensive assessment of the geographic distribution of solar investment opportunities. The inclusion of battery energy storage in the financial model, evaluated as both a standalone investment and a co-located complement to solar PV, represents a further priority for future work, given the growing economic case for storage dispatch optimisation as solar penetration increases. Finally, future research should examine the implications of planned transmission infrastructure upgrades for nodal price dynamics and site-level project economics, to provide investors and developers with a forward-looking assessment of how the network investment programme may alter the relative attractiveness of candidate sites across the country.

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