2025 Generation Stack Report

Prepared for Transpower New Zealand Ltd
Prepared by Beca Limited & Concept Consulting Group Limited

11 September 2025

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Revision History

Revision Nº	Prepared By	Description	Date
0	Beca / Concept	Working Draft for Client Feedback	04/07/2025
1	Beca / Concept	Draft Issued for Workshop	25/07/2025
2	Beca / Concept	Final Issue with updated CSIRO numbers and refinements from draft feedback	22/08/2025
3	Beca / Concept	Final Issue	11/09/2025

Document Acceptance

Action	Name	Signed	Date
Prepared by	David Weaver		11/09/2025
	Barry Wallace		11/09/2025
	James Innes		11/09/2025
	Ruth Jervois		11/09/2025
Reviewed by	Kevin Friesen		11/09/2025
Approved by	John Duffy		11/09/2025
on behalf of	Beca Limited		

Abbreviations and Definitions

AC	Alternating Current	KWD2	Kaiwera Downs 2
AEMO	Australian Energy Market Operator	kWh	Kilowatt-hour
AUS	Australia	M	Million
BBI	Benefit-based investments	MBIE	Ministry of Business, Innovation and Employment
CCGT (Thermal)	Combined Cycle Gas Turbine	MW	Megawatt
CCUS	Carbon Capture, Utilisation and Storage	MWh	Megawatt-hour
CSIRO	Commonwealth Scientific and Industrial Research Organisation	n-1 reliability	A connection with a higher level of reliability. It is able to withstand the loss of one connection asset and still remain connected.
CSP	Concentrated Solar Power	NREL	National Renewable Energy Laboratory
DC	Direct Current	NZ	New Zealand
DOE	Department of Energy	NZD	New Zealand dollars
EA	Electricity Authority	NZWEA	New Zealand Wind Energy Association
EIA	Energy Information Administration	O&M	Operations and Maintenance
EIPC	Electricity Industry Participation Code	OCGT (Thermal)	Open Cycle Gas Turbine
EMI	The EA's Electricity Market Information website	pa	Per annum
FOM	Fixed Operating and Maintenance Costs	PV (Solar)	Photovoltaic Solar
Gencost	Electricity Generation Cost Report	PwC	PricewaterhouseCoopers
Gentailers	Generator-Retailers (Energy companies that manage both generation and retail)	SMR	Small Modular Reactor (Nuclear)
GJ/GWh	Gigajoule per Gigawatt-hour	Stack	Generation Stack
GW	Gigawatt	TJ	Terajoule
GXP	Grid Exit Point	UGS	Underground gas storage
IEA	International Energy Agency	UK	United Kingdom
km	Kilometre	US / USA	United States of America
kV	Kilovolt	USD	United States of America Dollars
kW	Kilowatt	VOM	Variable Operating and Maintenance Costs
kWAC	Kilowatt Alternating Current	yr	Year
KWD1	Kaiwera Downs 1		

Executive Summary

This report has been commissioned by Transpower New Zealand to:

1. Produce an updated assessment of electricity generation technologies' capital costs and cost trajectories for New Zealand out to 2060; and

2. Apply these trajectories to review and update the generation stack currently used by Transpower in its forward planning activities, held in Appendix F of The Transpower Assumptions book.

Prepared by Beca and Concept Consulting, the 'Generation Stack' report presents a comprehensive set of cost estimates and critical performance parameters for a range of electricity generation technologies. Covering a range of proven, potential, and speculative generation sources, the report consolidates capital expenditure, operational costs (excluding fuel costs), efficiency metrics, and scalability considerations to facilitate informed decision-making in energy planning. The report is particularly instrumental for Transpower, the owner and operator of the national transmission grid, which uses the 'Generation Stack' data to make informed assumptions regarding the timing, scale, and location of new generation technologies in key operational contexts.

Whilst prepared for Transpower, the report has been prepared to also provide information to all stakeholders across the energy sector, to help understand the cost of building new generation and the regional resource availability. Like previous stack reports, every effort has been taken to use the most current data to support the analysis undertaken and this has also involved subjective judgements being made about the probability of future events and cost trajectories. The results produced should not be relied upon to underpin specific project investment decision making.

The 'Generation Stack' update provides a snapshot of the current cost of developing generation in New Zealand and an associated forecast for where costs might trend in the future. In developing the 'Generation Stack' the Beca and Concept Consulting team have drawn on published information about current projects in New Zealand, including previous 'stack' reports as well as international forecasts. We have also consulted with some of the major developers in New Zealand as part of this process.

This report is accompanied by a spreadsheet that includes overnight capital costs and operating and maintenance costs for generation technologies through to 2060. The spreadsheet includes project specific forecasts for wind and solar generation and can be used to explore high and low-cost scenarios.

Generation technologies have progressed since the previous generation stack reports were prepared for the Ministry of Business Innovation & Employment (MBIE) in 2020. As such it is appropriate to revisit these technologies and provide an update.

Some of the key observations about costs for new and old generation technologies are:

1. Solar and battery storage costs have declined rapidly over the past few years and are forecast to continue to do so, at least until the mid-2030s. These technologies are both areas of intense international research which drives their rapid learning rate.

2. Wind energy remains a key technology for the future, but unlike for batteries and solar, cost reductions are less certain. There seem to be two schools of thought: one anticipating a substantial decrease in costs off the back of increased production capacity globally; the other expecting no change or a slight increase as increased supply can still not keep up with demand.

3. New Zealand has world class geothermal resource and current costs reflect this advantage. However, there is less scope for cost reductions in the future as this is a more mature technology.

4. The economics for both residential solar and residential batteries continue to improve, but it is noted that this may not be an accurate predictor of uptake.

5. Gas Turbines have seen an increase in costs recently and are not expected to reduce significantly in cost for the next three years, gas reciprocating engines may provide a cost-effective alternative.

6. For all fuel based thermal generation technologies; the potential inclusion of carbon capture, utilisation and sequestration technology is nascent and is not expected to be economically viable in the short to medium term.

When preparing these numbers, the intention has been to clearly explain and provide a clear rationale for the chosen methodology. Any specific cost forecast may prove incorrect over time, but provided that the relative costs between technologies are correct, the economic modelling should still provide the right outcomes. Additionally, it is expected that if a sound methodology is used then the underlying values can be updated as costs develop over time.

1 Background and Purpose

Transpower has commissioned Beca and Concept Consulting to compile a database of the overnight capital costs and operating and maintenance costs for various generation technologies and how those costs will change over time (a "generation stack").

The purpose of this information is to inform Transpower's Te Kanapu work programme, specifically the development and assessment of various potential National Grid development scenarios that are developed, modelled and assessed as part of the strategic planning work to inform the Future Grid investment plan modelling. The information in this report will also be used to inform Major Capital Expenditure (Capex) Proposals and Transmission Pricing of Benefit-Based Investments. The associated cost database will be published and, whilst we anticipate it will be of use to other participants in the market, the data should not be relied upon to inform project specific investment decision making where more detailed project specific information will be critical.

Similar publicly available resources already exist. Most notably:

- Ministry of Business, Innovation and Employment's (MBIE) 2020 generation stack updates.
- Transpower's existing generation stack as part of their BBI assumptions book.

This report is an update on Transpower's existing generation stack, but uses a new standardized approach to estimate costs, and is a standalone undertaking.

MBIE's generation stack is highly detailed, comprising five separate reports for different technology types, released by different parties over the course of 2020. This report does not go into this is level of detail for each individual technology type. It has been informed by the previous stack reports, particularly identified projects, and includes additional information for a wider range of current and potential technologies to reflect the substantial advancement in some of these since 2020 and changs to the cost data assembled at that time.

When compared to the previous MBIE generation stack, this report has been prepared using consistent sources and assumptions where possible. This helps to standardise our estimating approach consistently between technologies, meaning that cost differences are driven by underlying effects.

For wind and solar our data is presented at a project level. Where possible, we have used real potential projects and adjusted costs appropriately. We also include "generic" projects within each region. For other technologies we have a standardised cost curve and separately note any applicable regional differences.

This report also estimates costs for certain storage technologies, as these are becoming increasingly important with the transition to a low emissions system.

2 Methodology & Assumptions

2.1 Methodology

Our overall methodology for calculating overnight capital costs is similar for most technologies. In the most general of terms, our methodology is:

1. Identify the current "typical" cost of the technology in New Zealand.

2. Use international forecasts to predict how those costs will change over time.

3. Adjust high level costs to specific projects if necessary.

1) Identify the current cost of the technology in New Zealand

Where possible, we rely on publicly disclosed costs for recent projects. This approach works well for onshore wind, utility scale solar, geothermal, batteries and some forms of thermal. For less well-developed technologies, New Zealand-specific costs are not available, so we rely on international estimates, appropriately adjusted for New Zealand.

We also adjust costs to a 2025 basis to the extent possible (e.g. a solar project 4 years ago would be significantly cheaper to build today). The costs presented in this report are presented on a completion date basis, so a "2025" cost is the cost for a project that would be completed in 2025.

2) Use international forecasts to predict how those costs will change

Our standard approach for forecasting how costs change over time is to refer to NREL and CSIRO's forecasts. Although there are multiple international forecasts, we consider these two to be the most relevant and useful for our purposes:

- NREL is the "National Renewable Energy Laboratory" from the United States of America. There are multiple sources from the United States of America (EIA, NREL, DOE), and we choose NREL as the most well regarded of these. It appears that many of the other US based forecasters refer back to NREL sourced material.
- CSIRO is the Commonwealth Scientific and Industrial Research Organisation from Australia. We include this source because it is particularly relevant to New Zealand. Although there are obvious differences between the New Zealand and Australian energy sector, there are also many similarities – we are both isolated islands with (globally speaking) small economies. Additionally, we have very free trade between the two countries and suppliers often treat the two countries as a common market, so many component costs will be similar.

Our default approach is to use the simple average of trajectories from these two sources. However, sometimes they differ significantly, and one is much closer to our current estimate of costs in New Zealand. When this is the case, we may weight that forecast more heavily.

Note that NREL and CSIRO forecasts do not extend to 2060, so we have used the average learning rate from the final forecast years to extrapolate costs to 2060.

However, NREL and CSIRO forecasts primarily provide a total cost forecast. We use separate connection costs and site accessibility related costs to estimate costs for specific wind projects and these costs will change at a different rate from the total cost. We have assumed that connection costs and other mature technologies will evolve at a mature learning rate of 0.35% pa.[1]

[1] This is the mature learning rate used by CSIRO in their GenCost report [1][1]

3) Adjust high level costs to the specific project

For wind and solar, our final output is costs for individual projects. Where possible these are based on real potential projects but also include generic projects for each region.

We go into more detail on how we derive our specific project costs in the wind and solar sections below.

However, note that we initially expected to find more key inputs that could be varied between projects (e.g., land costs, labour costs and so on), but upon investigation many potential influences on costs are second order compared to uncertainty in the underlying cost curve.

Estimating costs for individual projects within New Zealand involves a large degree of uncertainty and requires making assumptions that will significantly affect results. We address this inherent uncertainty and necessary assumption-making process by clearly stating where we have made assumptions and our reasoning for doing so.

2.1.1 High and low sensitivities

We provide high and low sensitivities for all forecasts. These are generally based on corresponding high and low sensitivities in CSIRO and NREL forecasts. However, neither of these sources refer to "high" and "low" scenarios as such.

Instead, CSIRO includes three scenarios adopted from the International Energy Agency's 2023 *World Energy Outlook*:

1. Current policies. This is the scenario with least government action on climate change and lowest investment in new renewable generation.

2. Global net zero emissions post 2050. This scenario has moderate renewable energy uptake and middle-of-the-range learning rates.

3. Global net zero emissions by 2050. This scenario assumes strong climate policy consistent with achieving net zero emissions by 2050.

One complication with this approach is that there is no clear low or high scenario in the CSIRO forecasts. Different technologies have different relative learning rates in different scenarios. We address this by using the lowest value across their three scenarios as the low scenario, and so on.

NREL includes the following three scenarios:

1. Conservative. We have used this as their "high" scenario as it represents a world in which learning rates are lower than expected.

2. Moderate. We have used this as their central scenario.

3. Advanced. We have used this as their "low" scenario because it represents a world in which learning rates are higher than expected.

Our high and low trajectories have a mature learning rate of 0% and 0.7% respectively.

One thing to note about the CSIRO and NREL forecasts is that their high, low and base scenarios are all identical for their starting year (2024 and 2023 respectively). This seems excessively precise, and we would expect some uncertainty in the starting cost. We have derived such a cost uncertainty for technologies in New Zealand that we have good data on (e.g. onshore wind and utility solar) and this is about 10% of the base estimate, so it is significant.

As such, we have incorporated a 10% starting error in our internationally derived forecasts. This is in addition to the subsequent divergence between scenarios. The two types of high and low-cost variation (i.e. starting cost uncertainty and cost trajectory uncertainty) are not necessarily correlated, but this approach produces reasonable high and low scenarios for sensitivity testing.

2.1.2 Operating and maintenance costs

We use a similar approach for operating and maintenance costs, although we lean more heavily on international values as there is less information available on New Zealand specific values.

2.2 Additional comments

2.2.1 Dollar values used in this report

All dollar values in this report are quarter 1 2025 New Zealand dollars unless stated otherwise. In other words, values shown are real, and not nominal. We do not take a view on future inflation rates.

Development costs in NZD are significantly affected by international exchange rates. We use historical annual average exchange rates and assume a future NZD/USD exchange rate of 0.60, and a future AUD/NZD exchange rate of 0.92.

2.2.2 Discussions with developers

We discussed our early findings with a small number of developers operating in New Zealand. We have made minor changes based on their feedback. We understand Transpower will consult on the assumptions independently.

2.2.3 Economies of scale

For each technology where a generic project cost has been provided, we have based this on a single typical project size and not attempted to incorporate allowances for economies of scale. Given the relatively small capacity of the New Zealand grid, it is difficult to achieve significant savings through economies of scale for projects beyond a size of 200 MW. Developing a project beyond this size typically requires higher grid connection costs to meet the grid security requirements, which reduces the impact of efficiencies of scale. Additionally, site specific factors are often observed to have a more significant impact than economies of scale.

CSIRO discusses the issue of modelling different project sizes in their Gencost report [1]. Notably, they state that they “often choose a single set of parameters to represent a broad class (e.g., selecting the most common size” when selecting technologies. This is consistent with the approach that we have adopted.

2.2.4 Overnight capital costs

All capital costs provided in this report are “overnight capital costs”. Overnight capital costs are the cost if the project could be completed “overnight”. In reality, projects take many months or years to complete, and this leads to additional financing costs that are incurred during construction. We have not considered these financing costs, except to note that projects with longer construction durations are more impacted by this effect.

Unless stated otherwise, we also assume that disclosed costs are overnight capital costs.

2.2.5 Connection costs

Capital costs provided in this report include connection costs.

3 Resources

Our report draws upon existing resources, both international and local. These are:

1. CSIRO: *Final GenCost* (2024-2025). https://www.csiro.au/-/media/Energy/GenCost/GenCost-2024-25-Final_20250728.pdf
2. NREL: *2024 ATB workbook* (2024). https://data.openei.org/files/6006/2024_v3_Workbook.xlsx
3. Aurecon: *2024 Energy Technology Cost and Technical Parameter Review* (2024). https://aemo.com.au/-/media/files/major-publications/isp/2025/aurecon-2024-energy-technology-costs-and-technical-parameter-review.pdf?la=en
4. UK Department for Energy Security and Net Zero: *Electricity generation costs* (2023). https://www.gov.uk/government/publications/electricity-generation-costs-2023
5. CSIRO: *Small-scale solar PV and battery projections* (2024). https://aemo.com.au/-/media/files/major-publications/isp/2025/CSIRO-2024-Solar-PV-and-Battery-Projections-Report
6. Energy Markets & Policy (Berkeley Lab): *Land-Based Wind Market Report* (2024). https://emp.lbl.gov/wind-technologies-market-report
7. MBIE: *Wind Generation Stack Update* (2020). https://www.mbie.govt.nz/assets/wind-generation-stack-update.pdf
8. Contact: *International Roadshow* (2022). https://contact.co.nz/getContentAsset/977ecb82-9b06-4683-a538-702694f7dbb9/a677e4b4-b3c2-492c-ae74-9399720288b8/2022-international-roadshow-presentation.pdf
9. US Energy Information Administration (EIA): *Capital Costs and Performance Characteristics for Utility-Scale Electric Power Generating Technologies*, January 2024
10. International Energy Agency (IEA): *Projected Costs of Generating Electricity* (2020) https://www.iea.org/reports/projected-costs-of-generating-electricity-2020
11. NREL: *The National Renewable Energy Laboratory Wind Analysis Library (NRWAL).* https://github.com/NREL/NRWAL
12. BEC: *New Zealand Offshore Wind Industry* (2024). https://bec.org.nz/wp-content/uploads/2024/05/Offshore-Wind-National-Impact-Study_-BEC-presentation-11.04.24.pdf
13. GWEC: *Global Wind Report* (2025). https://26973329.fs1.hubspotusercontent-eu1.net/hubfs/26973329/2.%20Reports/Global%20Wind%20Report/GWEC%20Global%20Wind%20Report%202025.pdf
14. NREL: *Wind Power Project Repowering: Financial feasibility, Decision drivers, and supply chain effects* (2013). https://docs.nrel.gov/docs/fy14osti/60535.pdf
15. GHD: *Gas Infrastructure Cost* (2025) https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2025/2025-gas-infrastructure-options-report/2025-gas-infrastructure-costs-report.pdf
16. MBIE: *Future Geothermal Generation Stack* (2020) https://www.mbie.govt.nz/assets/future-geothermal-generation-stack.pdf
17. MBIE: *From the Ground Up* (2025) https://www.mbie.govt.nz/dmsdocument/30975-from-the-ground-up-a-draft-strategy-to-unlock-new-zealands-geothermal-potential-pdf
18. NREL: *Cost of Wind Energy Review* (2024) https://docs.nrel.gov/docs/fy25osti/91775.pdf
19. MBIE: *Offshore Renewable Energy Regulatory Regime* (2024) https://www.mbie.govt.nz/dmsdocument/28535-offshore-renewable-energy-regulatory-regime-policy-decisions-proactiverelease-pdf
20. MBIE: *Offshore Renewable Energy* https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-generation-and-markets/offshore-renewable-energy

4 Project Classifications

The report is intended to cover a comprehensive range of generation technologies. As such, we have not excluded any generation technology for which we can source credible cost data. However, we have grouped technologies into "proven in New Zealand", "potential" and "speculative" to narrow our areas of focus. We have defined the technology groupings as follows:

Proven technologies - are those currently active at reasonable scale in New Zealand. We cover these in most detail, and particular effort is paid to the New Zealand specific cost component.

Potential technologies - are technologies that may be somewhat more common overseas, but which are not currently developed in New Zealand. Forecasts for these technologies rely heavily on international forecasts with relatively crude adjustments to the New Zealand market.

Speculative technologies - are those with limited cost information worldwide, and we do not provide cost estimates as we do not have a credible basis to make such forecasts.

Technologies that are covered in this report are listed in Table 4-1.

Table 4-1 – Generation and storage technologies

Technology	Sub-type(s)		Classification
Onshore wind	New		Proven
	Repowering		Proven
Solar	PV	Utility-scale	Proven
		Residential rooftop	Proven
	Solar thermal	Concentrated solar power	Potential
Battery	Utility-scale	Short duration (2-hour)	Proven
		Medium duration (10-hour)	Proven
	Residential		Proven
Geothermal	Conventional	Flash	Proven
		Binary	Proven
	Deep geothermal		Speculative
Hydroelectric	Conventional		Proven
	Pumped hydroelectric storage		Potential
Thermal	CCGT	No CCUS	Proven
		With CCUS	Proven
	OCGT	No CCUS	Proven
		With CCUS	Proven
	Rankine Cycle	No CCUS	Proven
		With CCUS	Proven
	Reciprocating Engine	No CCUS	Proven
Gas storage	Underground gas storage		Proven
Offshore wind	Floating		Potential
	Fixed		Potential
Hydrogen	Hydrogen fuel cell		Speculative
Nuclear	Fission	Small modular reactors	Potential
	Fusion		Speculative
Ocean	Tidal range		Speculative
	Ocean current		Speculative
	Wave		Speculative

5 Proven Technologies in New Zealand

5.1 Onshore Wind

Onshore wind is a proven technology in New Zealand and is likely to be one of the main technologies to meet demand growth in the future. Cost estimates for wind will have a large effect on any modelling exercise, and so we have paid particular attention on current and future wind costs. Onshore wind is also one of two technologies for which we have produced project specific costs.

5.1.1 Current cost estimate

Our primary input for estimating current wind project costs in New Zealand is published costs for recent projects. The majority of these come from disclosures by large gentailers so are highly reliable values. Figure 5-1 shows total project costs for recent (i.e. since 2019) and potential wind projects.

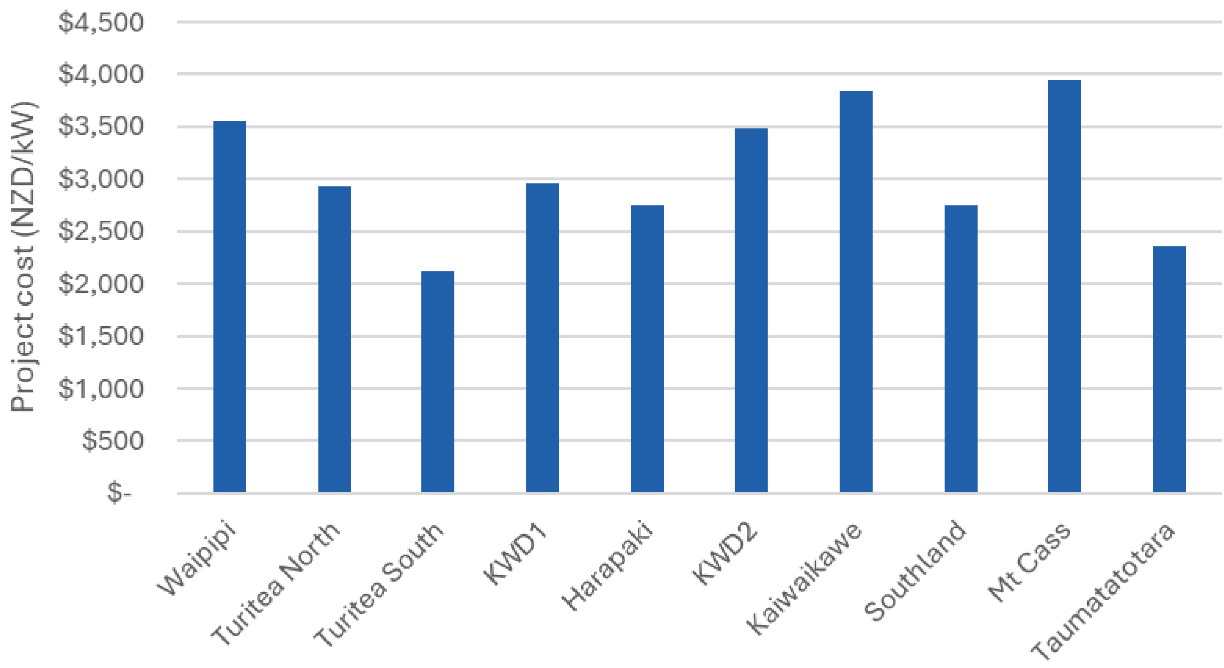

Figure 5-1 - Project capital costs for recent and potential wind farms

However, there is a large spread in project costs, which makes estimating a representative value difficult.

Turbine costs make up a majority of project costs. Turbine costs are subject to international market rates and exchange rates. They change over time and may explain some of the cost difference seen in Figure 5-1.

We have removed the effect of turbine costs in Figure 5-2, showing only non-turbine costs for projects and a comparable global average value [6]. Non-turbine costs are more site dependent and there may be a systemic difference in these costs in the New Zealand market compared to overseas.

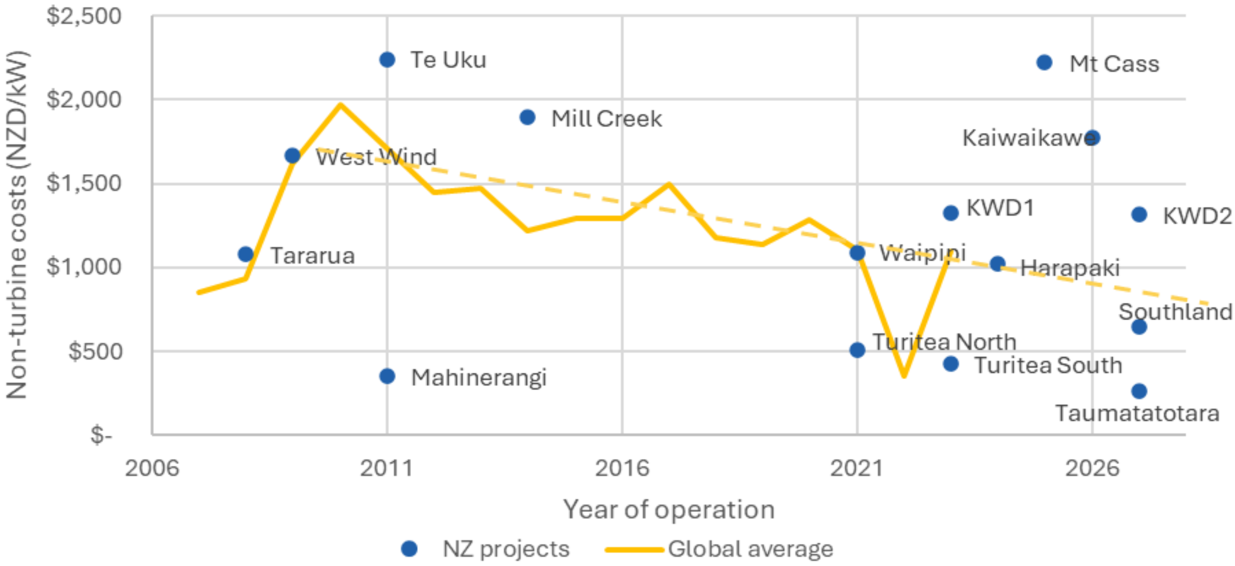

Figure 5-2 - Non-turbine costs for NZ wind farms (real)

The global average non-turbine cost peaked in 2010 and has been slowly declining since. 2022 data was affected by Covid-19 disruptions, but 2023 appears to be a return to normal.

Prior to 2020, non-turbine costs for New Zealand projects were slightly higher than the global average.[2] However, more recently this relationship has been more complicated, with projects falling above or below the global average. Most of the cost outliers can be explained:

- Mt Cass3 has been put on hold and appears unlikely to be developed in the immediate future, primarily due to poor project economics, and the higher-than-average non-turbine costs are consistent with this.
- On the other hand, Kaiwaikawe is committed, and work has begun. This project is located in Northland, so it has a favourable wholesale market location pricing factor, and also a favourable wind resource. These two factors will have contributed to the project's approval, despite higher than usual non-turbine costs.
- Turitea had aspects of a "brownfield" development. Consents would have been easier to achieve given the existing wind turbines in the region, the developer was able to call upon personnel familiar with the location and utilize some existing connection assets, while relatively minor, these benefits will have helped to keep costs low.
- Taumatatotara is earlier in the planning process than other projects, and cost estimates may be less reliable.

The remaining, recent projects (Kaiwera Downs 1 and 2, Harapaki, Southland and Waipipi) are much closer to the global average trend.
Given this, our view is that non-turbine costs are somewhat higher than the global average in New Zealand. We also observe that they are site dependent, and do not have a clear trend over time.

Our estimate for current non-turbine costs for a typical project is 1,400 $/kW. This value will vary between different projects, and we discuss this effect further in section 5.1.4 below.

[2] Mahinerangi appears to be an outlier, which may reflect inaccurate cost data.

[3] Mt Cass is shown as being completed in 2025 (despite not being completed in 2025), as this was the expected completion date for the cost estimate provided.

Our estimate of the 2025 turbine cost is about 2,000 $/kW. This results in a total project cost of about 3,400 $/kW for a typical project. Our estimate of 3,400 $/kW is between the adjusted costs of Kaiwera Downs 1 and Kaiwaikawe, and similar to the cost for Kaiwera Downs 2.

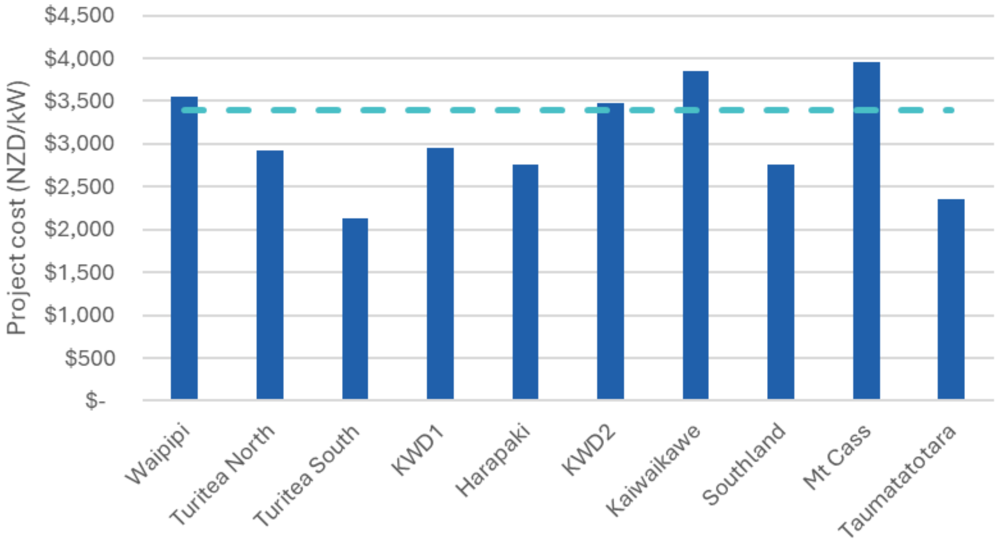

Figure 5-3 - Project capital costs for recent and potential wind farms (including "typical" value)

There is some uncertainty over this value, and sensitivity analysis may be appropriate. A range of 3,100 to 3,700 $/kW would be reasonable.

5.1.2 Cost trajectory

Even adjusting for inflation, the cost of wind projects has increased in the past five years, contrary to expectations. The “cost for 2025 wind in 2025” from CSIRO is roughly 50% higher than its “cost for 2025 wind in 2021”. NREL has also seen an increase of about 20% in real terms over a similar timeframe. Partly this is due to disruptions caused by Covid-19 but also includes higher turbine costs due to increased warranty costs and an apparent reduction in price competition between major suppliers.[4]

We consider the recent cost increases to be an anomaly and that prices will return to a learning rate driven trend.

[4] Aggressive pricing strategies in the early 2020s lead to negative returns for many turbine manufacturers, but Vestas (at least) has returned to profitability since 2024. https://www.reuters.com/business/energy/wind-turbine-makers-struggle-find-pricing-power-2022-05-05/. https://www.reuters.com/business/energy/wind-turbine-maker-vestas-q4-profit-beats-expectations-drops-dividend-2024-02-07/

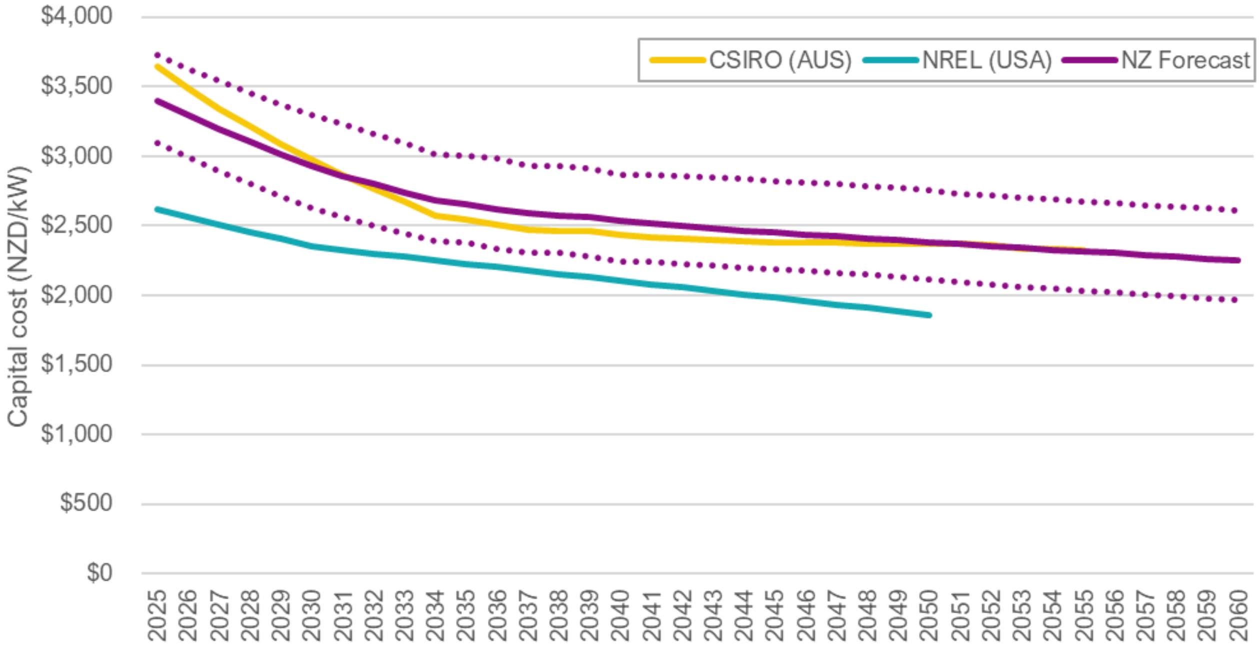

Figure 5-4 - Projected costs for onshore wind[5]

Figure 5-4 shows our two reference international forecasts, as well as our forecast for New Zealand, including high and low bands. CSIRO's cost of wind is significantly higher than NREL's Our estimate of the current New Zealand project cost is very close to the CSIRO value. Our New Zealand cost projection is derived by applying the average absolute reduction in costs for the two international forecasts to our New Zealand starting point. This results in a cost trajectory for New Zealand wind that does not drop as rapidly as the CSIRO forecast and becomes higher than the CSIRO value by the early 2030s.

Over the long term, we expect costs in New Zealand to be marginally higher than in Australia. Partially this is due to our propensity to build projects in more difficult to access (but windier) areas. This limits the maximum turbine size possible which also limits potential project cost reductions. Note that our forecast is for a "typical" wind project, and sites with very good accessibility and low connection costs will be lower than this, and more similar to Australian costs over the longer term.

Our forecast is consistent with this through the 2030s and 2040s, although by the 2050s our costs are similar to or slightly lower than CSIRO's forecast. This is due to NREL expecting a higher learning rate through the 2030s and 2040s, which we have incorporated into our longer-term forecasts.

During the course of our discussions with large developers, some parties provided a view that *any* cost reductions were unlikely, perhaps mindful of the recent uptick in wind project costs. However, our view is that modest cost reductions are likely, although not to the extent forecast by CSIRO. CSIRO describes their cost trajectory to 2035 as a "return to its normal cost path" – in other words, they expect rapid cost decreases *because of* the high-cost increases seen recently, rather than in spite of them.

5.1.3 Chinese-sourced wind turbines

Our New Zealand project costs are calibrated on projects that use European sourced wind turbines (Siemens or Vestas). We understand that Chinese based manufacturers are reportedly able to supply turbines at a significantly lower price. Turbines supplied by Chinese based Goldwind have been used in at least one

[5] Dotted lines indicate high and low cost scenarios for this figure and all similar subsequent figures.

recent Australian project, and Goldwind states that they operate in New Zealand, although we are not aware of any existing or potential projects that use their turbines.

Irrespective of the source of turbines, additional competition in a market with a very small number of suppliers will lead to lower prices. Our base case assumption is for prices to fall, and increased competition is consistent with this.

5.1.4 Specific project costs

The next step in estimating costs for specific projects is to modify our cost curve for a "typical" project using information about each specific project.

Our goal when undertaking this step is to focus on key factors only. Given the inherent uncertainty in forecasting costs, if the size of an effect is relatively small, including it will lead to false precision and not meaningfully improve the modelling process.

Accordingly, we started with a long list of potential factors including:

- Land costs
- Cost of labour
- Connection costs
- Site accessibility
- Turbine costs
- Economies of scale

We discuss the importance of each of these factors below and whether we have included them in our model.

5.1.4.1 Land costs

Wind farms are different from some other technologies in that the land can continue to be used while the wind farm operates. Given this, it is common to lease the rights to use land rather than purchase it.

We have used NZWEA's published[6] estimate of 1,500 to 6,000 $/MW/yr for the annual lease costs for a wind farm. This is consistent with our internal estimate of 2,500-5,000 $/MW/yr. Using an annual capital recovery requirement of 8% on a 3,200 $/kW wind farm results in an annuity of 256 $/kW/yr, or 256,000 $/MW/yr meaning that the *total* spread in the NZWEA's estimate of land costs amounts to about 1.8% of the total project cost. This level of variation may be important from an individual project economics viewpoint, but it is not significant for our purposes, especially given that regional differences will only account for a portion of this variation.

5.1.4.2 Labour costs

Similarly to land costs, labour costs vary across the country. We have reviewed public data that suggests that construction labour rates can vary by ~5% between major centres in New Zealand. However, much of the construction crew will be highly skilled personnel who are not locally sourced.

Additionally, labour costs typically make up about 6% of wind project costs, [11] so a 5% variation on this input cost results in about a 0.3% variation in total project costs.

As for land costs, we do not consider this level of difference to be relevant from a regional system planning perspective.

5.1.4.3 Connection costs

Connection costs refer to the cost of connecting to transmission or distribution networks. This is a significant cost and NREL Annual Technology Baseline [2] estimates that it makes up about 7% of a wind farm's cost.

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[6] https://www.windenergy.org.nz/wp-content/uploads/2024/06/FactSheet-Considering-a-wind-farm-on-your-land.pdf

We take this into account when considering the cost for projects that we have high quality location data for. Our estimate is derived from a simple model that uses a distance to the grid, a connection voltage, new substation requirements, and a connection type (embedded or grid connected).

However, we do not vary connection costs for generic projects in different regions. This is because we do not think there is a clear trend between regions. Furthermore, one of the purposes of this generation stack is to inform Transpower modelling of beneficial grid upgrades.

5.1.4.4 Site accessibility

Site accessibility refers to the costs that a developer must incur to access the site during the construction process. This will be influenced by proximity to ports, existing roading infrastructure and topology of the site. To quantify how this might vary between projects, we have used three approaches:

1. NREL's indicates that ~12% of project cost is due to wind turbine transport and site access [18], but we expect this to be higher in New Zealand given our propensity to build on hilltops rather than on more accessible plains. If we assume that transport and access costs are 50% higher on average in New Zealand, then this adds a cost premium of about 260 $/kW for a typical NZ site compared to a more easily accessible one.

2. Our estimate for non-turbine costs in New Zealand is about 1,500 $/kW, compared to a global average of about 1,000 $/kW. It's likely much (but not all) of this difference reflects the difference in typical topology chosen. If half of this difference is due to different topology, then this suggests a cost premium of about 250 $/kW for a typical NZ site compared to a more easily accessible one.

3. A portion of the range of non-turbine costs in Figure 5-2 will be due to different accessibility for different projects. The standard deviation of these costs is about 500 $/kW. If a quarter of this variation was due to accessibility of sites then this would suggest a variation of ~125 $/kW. However, given that there is likely to be less variation in existing project accessibility than we expect to see in the future, this value may be an underestimate.

While these are all crude estimates of the site driven cost variability, they are broadly similar. As such, we have estimated that the most accessible sites in New Zealand are 200 $/kW cheaper than the average, and the least accessible sites are 200 $/kW more expensive.

We have classified potential projects into these three categories based primarily on a qualitative desktop review of proximity to ports, existing roading infrastructure and topology of the site.

5.1.4.5 Turbine costs

Turbine costs make up a majority of the total project cost, and turbine costs change significantly over time based on the international market and the New Zealand exchange rate. As such, they are important to forecast accurately.

However, we have not explicitly varied turbine costs when looking at cost differences between different projects. This is because the final project site does not directly influence the price paid for turbines.

Note that we *would* expect some variation in the cost to transport turbines, and the installation cost for the turbines, but this is captured in our site accessibility metric.

We are aware that as the standard size of turbines continues to increase, some particularly inaccessible sites may not be able to utilize these very large turbines. This would effectively increase the cost of turbines for these projects. Currently we believe we have sufficiently captured any such effect in our site accessibility cost variation. We will continue to monitor the impact of turbine size limitations and may explicitly include it in future updates.

5.1.4.6 Economies of scale

Most generation technologies are subject to some economies of scale. With larger projects, fixed costs can be spread across more generation, leading to lower costs on a per unit basis. However, we have not explicitly included project size when estimating costs for specific projects.

We have, however, accounted for economies of scale by explicitly modelling connection costs, as described above. Modelled connection costs do not scale linearly with project size, so smaller projects will have higher costs on a $/kW basis. This functionally reduces costs for larger projects and implements "economies of scale".

Note that the major "economy of scale" for wind projects relates to turbine size since larger turbines are more efficient at capturing wind energy. However, project size does not dictate turbine size – larger projects will normally have more turbines, rather than bigger turbines.

Generic projects

So called "generic projects" are hypothetical projects that do not have a specific site and are not based on an announcement to develop. They are required to fill out the supply curve, both from a modelling perspective, but also because there will be new projects developed by 2060 that are not currently being investigated.

While most projects to date have been in windier, less accessible locations, this may change in the future.

Accordingly, we include two types of generic wind plant in our wind supply stack. The first being "hilltop" sites that continue the observed behaviour of building in harder-to-access areas. We ascribe a higher cost to these sites to reflect the higher civil and connection costs associated with this approach. These are placed at the top of the existing project cost curve.

We also include "plains" generic wind projects. These are assumed to be much easier to access and have moderate connection costs.

The generic plains projects are intended to be paired with an appropriately derated wind resource curve that reflects the lower expected capacity factor. Appropriately derating the capacity factor is not part of this project and is not straightforward.

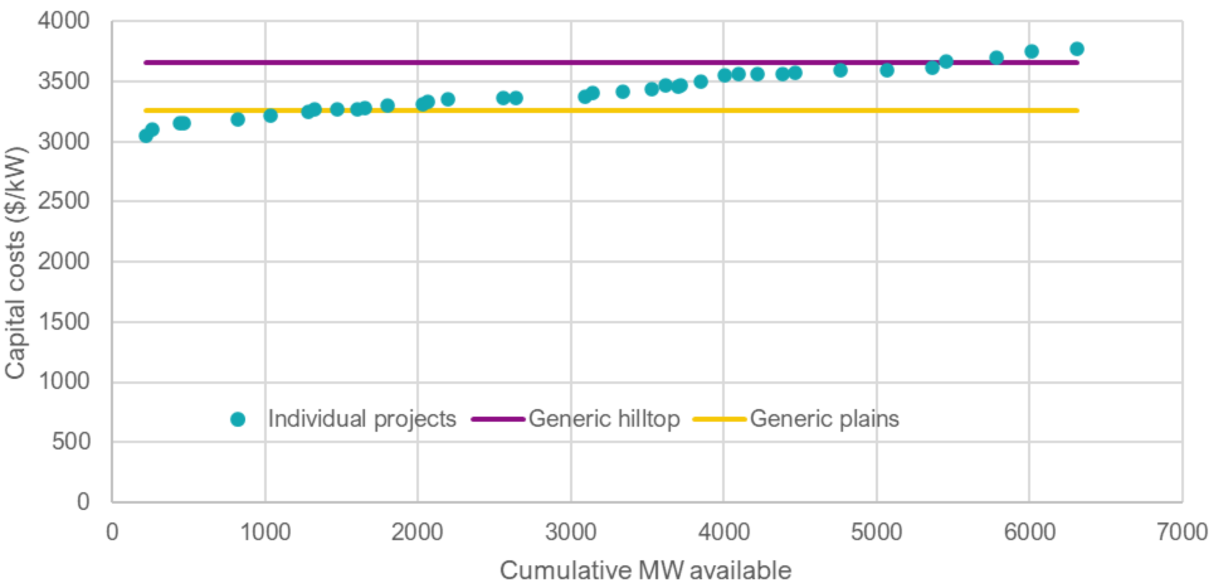

Figure 5-5 - Estimated wind supply curve

Figure 5-5 shows the result of this process. The average 3,400 $/kW value is adjusted for connection cost and site accessibility for each project and wind projects are then sorted from cheapest to most expensive.

Generic projects are also shown. Generic hilltop are similar to the most expensive known projects, while generic plains are similar to the cheapest known projects due to having much lower site accessibility costs and lower connection costs.

5.1.5 Operating and maintenance costs

There is much less information available on New Zealand specific wind operating and maintenance (O&M) costs. As such we rely on international forecasts for estimating the current level and trajectory of these values. Both CSIRO and NREL produce fixed operating and maintenance costs (FOM) for onshore wind, and we use the simple average of these values.

We apply the same FOM for each project as these do not vary significantly by site.

Our estimate for variable operating and maintenance costs (VOM) is zero. Both CSIRO and NREL state a VOM of zero, and that all operating and maintenance costs are captured in the FOM cost.

Maintenance contracts for wind turbines are normally based on a time period rather than a number of running hours. This means that feathering blades and turning off wind turbines does not reduce maintenance costs in practice.

We also raised this issue with wind developers during our pre-release discussions, and they indicated that zero VOM was a reasonable assumption and aligned with their maintenance contracts.

We understand that in practice wear-and-tear on wind turbine components will be reduced by not operating and so this suggests that moving some FOM costs to VOM costs may better reflect the underlying economics. We may address this issue in a later release if real world contracts begin to reflect this dynamic.

5.1.6 Comparison to previous generation stack

Wind was included in MBIE’s 2020 generation stack report bundle. The 2020 generation stack modelled results at a project level, similar to the final output of this report.

The 2020 generation stack report used a broadly similar approach to our generation stack. Potential sites were analyzed using a desktop review approach to produce an estimate of the cost for each potential project. However, there are some key differences:

1. The 2020 generation stack report did not provide the results of their analysis. This made it of limited use.

2. The 2020 generation stack utilized far more input parameters when developing their model and producing their cost estimates but did not provide details on how each parameter influenced results. Accordingly, their model was able to reproduce published values for two real wind projects very well. However, this may simply be due to overfitting (given enough parameters, any model can reproduce observations well). We believe our approach of only including key input parameters and explaining their effect is more defensible and robust, and more amenable to future updates.

3. The 2020 generation stack only used four “real” wind projects. There has been a large increase in the number of potential wind projects in the last five years, which allows us to lean much more heavily on real projects to fill out the potential generation stack.

5.2 Repowering Onshore Wind

5.2.1 Current cost estimate

We have good data on current wind repowering costs in New Zealand because the initial wave of wind projects from the early 2000s is coming to end-of-life. Specifically, data is available for Te Rere Hau and Tararua wind farms.

Te Rere Hau has a reported cost of $500-600M to decommission the existing 45 MW wind farm and replace it with a larger wind farm with a capacity of up to 170 MW.[7] Tararua's equivalent values are $660M to repower the existing 160 MW wind farm with a new 220 MW wind farm.

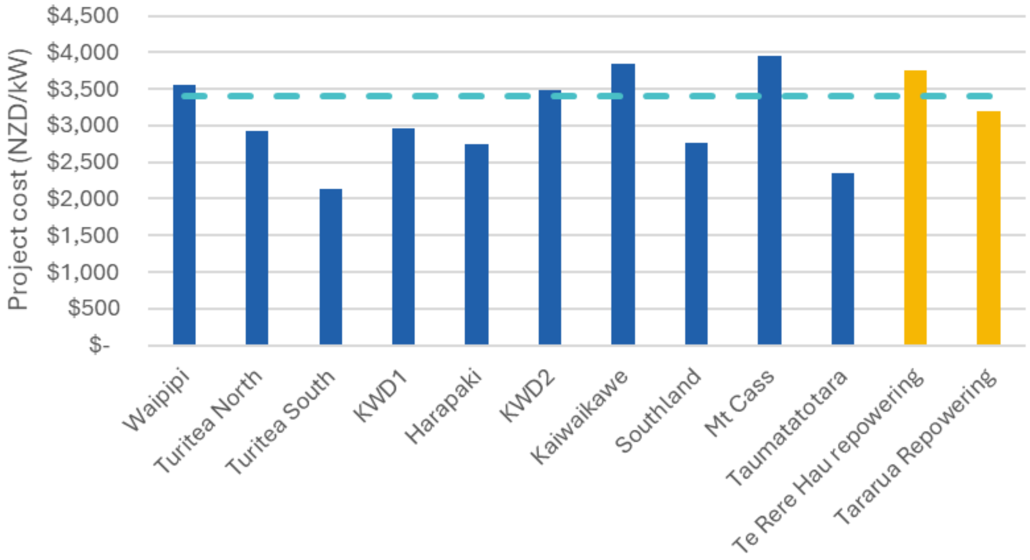

Figure 5-6 - Project capital costs for recent and potential wind farms (including "typical" value and repowering costs)

These inputs result in costs that are comparable to greenfield projects. Accordingly, it appears that these wind repowering projects are not significantly different to new wind farm projects.

While this may be surprising, it is consistent with international literature. An NREL report into repowering costs cites a cost of 2,550 $/kW for repowering vs a cost of 2,650 $/kW for a greenfield development [14]. This is well within the observed spread of new project costs.

Accordingly, our cost curve for wind repowering is identical for new wind, albeit much more limited in potential sites.

5.2.2 Cost trajectory

However, we expect this to change over time.

Repowering wind projects from the early 2000s have limited cost savings, because the size of turbines has increased dramatically. For example, Te Rere Hau has many 0.5 MW turbines while new onshore turbines are typically 3-5 MW. This dramatic increase in size means that much existing infrastructure (both electrical and civil) is unsuitable for the larger turbines. The project is not a "like-for-like" replacement. While wind turbines may increase in size in the future, they will not do so to the same extent, meaning that there may be more cost savings available.

[7] We have taken the upper end of this range as our cost estimate.

Accordingly, we consider all wind projects prior to Te Apiti to have replacement costs equal to a new project, but those that came after (including future projects) to have lower non-turbine costs.

There is little international information on the potential cost savings for *future* repowering (most information is on the cost to repower right now).[8] Instead, we have taken a high-level view on the re-usability of civil and electrical balance of plant components and consider a discount of 33% on non-turbine costs to be reasonable.

5.2.3 Specific project costs

We have applied the reasoning above to our list of wind projects.

5.3 Utility-scale Solar

5.3.1 Current cost estimate

We use a similar approach to wind for estimating solar costs. There are fewer existing solar plants in New Zealand, but no shortage of projects in various stages of development. One systemic difference with solar projects compared to wind is that there are more "independent" developers. This makes information more difficult to ascertain because independent developers are not subject to disclosure requirements like exchange listed entities.

Nevertheless, there are more potential projects with cost data than wind, simply because there are many more projects.

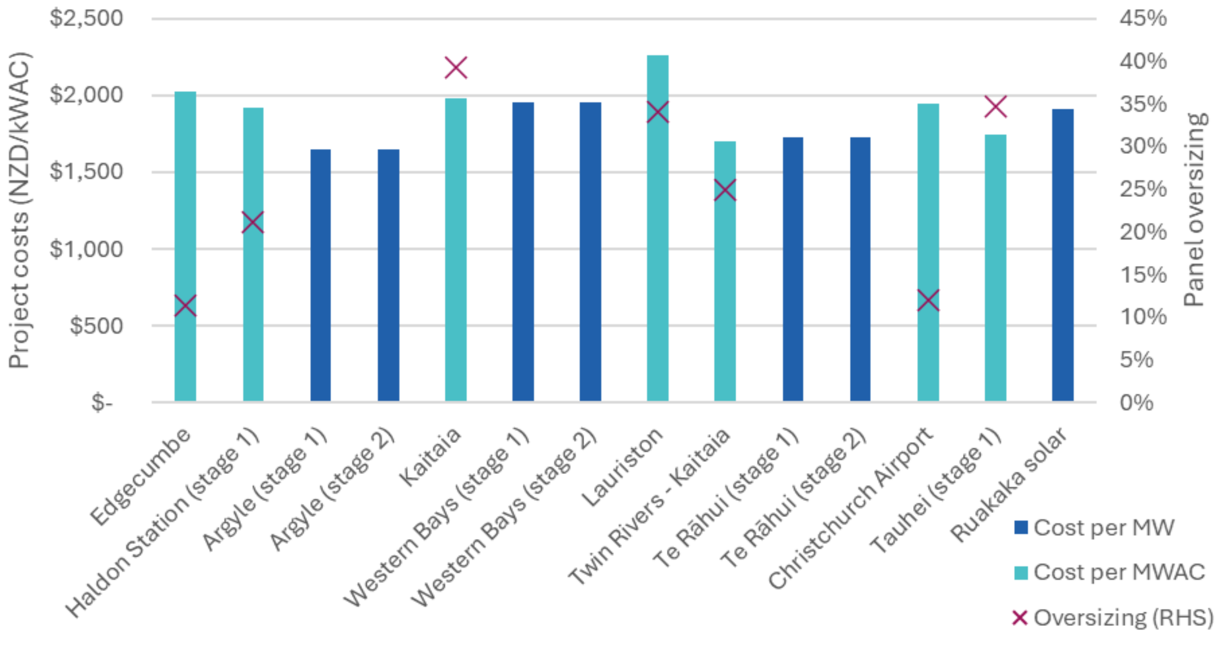

Figure 5-7 - Costs for recent and potential solar projects

[8] CSIRO provides a datapoint when comparing the 60-year cost of a wind farm compared to nuclear energy over the same timeframe. Their assumed repowering cost for a wind farm built now is very similar to their new wind farm cost 30 years in the future. However, it is not clear if this is a genuine forecast of future repowering cost, or simply illustrative to demonstrate that wind power is significantly cheaper, even without accounting for possible repowering savings.

Figure 5-7 shows project costs for recent solar projects. There is significantly less variability in project cost data for solar than wind. This is due to (at least) two main factors:

- Cost information was obtained over a shorter timeframe. The earliest wind project data was from 2019, and two additional projects were from 2022. The earliest solar project is from 2023. While we have attempted to adjust for inflation in all data, costs inflate non-uniformly, so this correction will be imperfect.
- Solar projects are more uniform in their design and less site specific than wind projects. There is genuinely less variability in costs, and this is reflected in cost data.

Having said that, there are some differences in solar projects. One design decision developers must make is the ratio of maximum AC power to maximum DC power. “Oversizing” panels involves installing solar panels that can produce more power than other electrical components can handle. This results in spilling power during the sunniest periods, but means more power is produced during less sunny periods (relative to solar farms with the same AC capacity that do not have oversized panels) and reduces construction costs relative to total generation. The maximum amount of generation from the solar panels is referred to as DC power, while the maximum amount that can be exported to the grid is referred to as AC power.

An additional factor to be considered for inverter sizing in New Zealand is the need to meet the Electricity Industry Participation Code (EIPC) requirements for reactive power contribution. By default, this reactive power requirement means that inverter capacity needs to be approximately 12% above the nameplate AC capacity if the project is grid connected. For distribution network connections greater or lesser requirements may apply depending on the specific agreement with the network provider.

The light blue bars in Figure 5-7 are projects that have reported both a DC and AC power value. The bars in darker blue have only reported a single value and it’s not always clear whether this is DC or AC. The dark blue bars are often lower which may be because they are a cost per MW DC and not comparable to the light blue bars. The crosses on Figure 5-7 show the extent of panel oversizing for projects where available. We have assumed a standard oversizing of 30%, and our cost estimate is for a project with this level of oversizing.

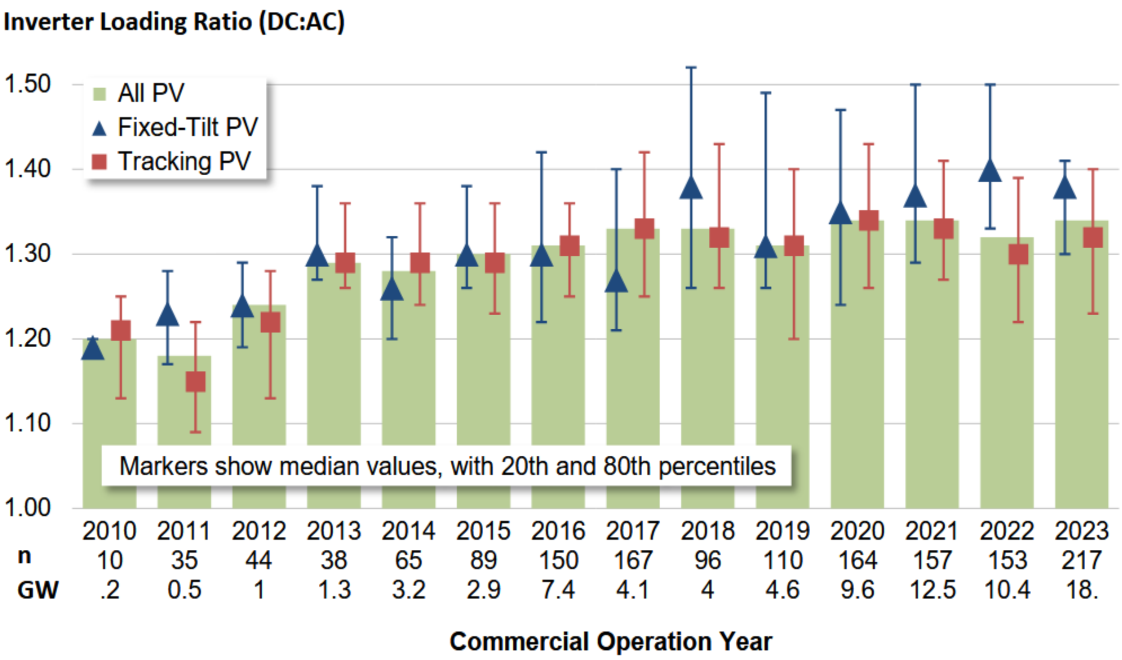

Figure 5-8 - US inverter load ratios (panel oversizing)

Figure 5-8 shows data of typical panel oversizing from NREL for the United States. A value of 30-35% appears typical for tracking PV and has been relatively constant for the period from 2017 to 2023. This is consistent with our observations in the New Zealand market.

Developers face a similar choice with fixed vs single or double axis tracking solar panels. The most common approach is single axis tracking as this gives the best trade-off between cost and performance. The values provided by CSIRO and NREL are for single axis tracking and our cost estimates for New Zealand are also for single axis tracking.

An additional complication with trying to estimate the current cost for solar is that prices are dropping significantly year-to-year. According to CSIRO numbers, a solar project from 2023 would be expected to be ~15% cheaper in 2025. We have adjusted costs from reported projects to account for this effect. Similarly to wind, we used expected completion date to adjust reported cost data to a 2025 equivalent.

Considering only the light blue projects in Figure 5-7, our estimated cost for current solar projects in New Zealand is 1,900 $/kWAC. There is some uncertainty about this value, and sensitivity analysis using a range of 1,700 to 2,100 NZD/kWAC is appropriate.

5.3.2 Cost trajectory

NREL's solar project costs are significantly higher than what we see in New Zealand. This appears to be partly because solar panels and inverters are subject to high import tariffs,[9] although this does not appear to completely explain the difference. In addition to tariffs, federal subsidies are available to some solar developers. This may lead to greater margins from developers and increase project cost. Overall, the solar market in the USA is heavily influenced by non-market factors and is not a particularly useful indicator for international prices. On the other hand, costs in Australia from CSIRO are also significantly lower (although the absolute difference is smaller than for NREL). This may reflect a more developed local market in Australia, and we note that our low forecast is very similar to CSIRO's forecast for the next decade.

While neither forecaster aligns with the situation in New Zealand right now, we use an average of the two forecasts, weighted slightly more towards CSIRO, as their current costs are closer to New Zealand, and we think their market is more representative of New Zealand.

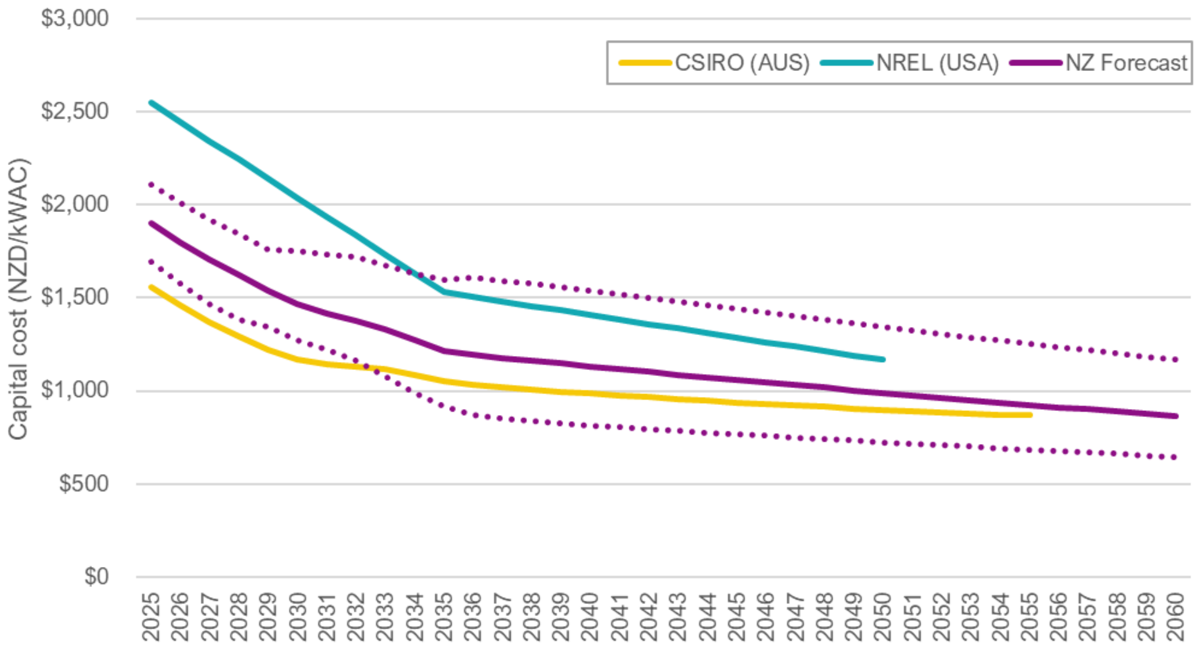

Figure 5-9 - Projected costs for utility solar

[9] Tariffs on imported solar panels to the USA are not a recent development and have been adjusted many times over the past decade. The tariffs are complex and differ depending on country of origin and panel type.

5.3.3 Specific project costs

Solar projects also have some site-specific costs. However, they are more homogenous than wind projects, primarily because the "solar resource" is more evenly distributed around the country than the "wind resource". Developers will not develop a solar farm if it has a significantly higher non-component costs such as connection cost or site accessibility issues.

Currently the majority of commercial solar farms appear to fall into two categories:[10]

- Larger than 150 MW and connecting to Transpower's 220 kV or 110 kV grid.
- Larger than 10 MW and up to about 80 MW and embedding in a local distribution network. This may involve connecting on the distribution side of an existing GXP or embedding deeper in the network.

We have separated known projects into these two categories. Embedded projects have a slightly lower cost due to a lower connection cost.

We assume that known projects will use up the majority of spare capacity on relevant distribution networks, so we assume that all additional generic projects are large and connect to the grid.

5.3.4 Operating and maintenance costs

There is much less information available on New Zealand specific solar O&M costs. One publicly disclosed data point is Meridian's Ruakākā development which states costs of 50 $/kW/yr. This is higher than international estimates and is higher than our experience with other potential projects in New Zealand. In our view, one data point is not sufficient evidence that costs are systemically higher in New Zealand.

As such we rely on international forecasts for estimating the current level and trajectory of these values. Both CSIRO and NREL produce FOM for solar, and we use the simple average of these values. NREL's O&M costs are higher than CSIRO's but not sufficiently so that we think they are unreliable. Additionally, we would not expect tariffs and subsidies to affect O&M costs to the same extent as capital costs.

We apply the same FOM for each project as these do not vary significantly by site.

5.3.5 Smaller scale utility solar

The costs provided in this section are for large-scale utility solar projects. We assume these projects are deployed by rational commercial entities and are expected to provide an economic return on capital when operating in the New Zealand wholesale market. In practice, not all solar projects are developed on this basis.

In particular, smaller scale (e.g. 1-10 MW) projects are more likely to be developed on a non-standard economic basis. This makes modelling the uptake of smaller scale utility solar challenging. Modelling smaller-scale utility solar may be more amenable to an assumption driven (rather than economics driven) approach, similar to residential rooftop solar uptake.

5.3.6 Comparison to previous generation stack

Utility solar was included in MBIE's 2020 generation stack update. However, the report is of limited use given the nascent state of the solar industry in New Zealand in 2020. The industry has advanced significantly in the previous five years.

Notably, the report used NREL estimates for costs in New Zealand. While this was a reasonable approach at the time, we have since discovered that NREL values tend to significantly overestimate New Zealand costs.

[10] Projects between 80 MW and 150 MW are less common because they are generally too large to be accommodated with existing distribution network capacity but are too small to justify to the cost of a new dedicated grid connection.

5.4 Residential Rooftop Solar

5.4.1 Current cost estimate

Residential rooftop solar is a fast-moving market and prices are rapidly dropping. Our approach to estimating costs is to use publicly advertised prices. However, we observed that suppliers frequently vary advertised prices, sometimes from one week to the next, which makes assessing a current value difficult.

We sourced advertised prices from five suppliers, and the average of these was about 1,925 $/kW.[11] We received advice from one supplier that advertised prices are a "best case" scenario, and given issues such as roof access, cable length and switchboard upgrades, a "typical" price is about 10% above advertised prices.

As such, our estimate of the current price for rooftop solar is 2,100 $/kWAC.[12]

5.4.2 Operating and maintenance costs

We assume that the capital cost includes a warranty which covers standard operating and maintenance costs for the majority of the life of the asset.

5.4.3 Cost trajectory

Unfortunately, as for utility scale solar, NREL's rooftop solar forecasts are inconsistent with what we see in the New Zealand market. As such, we have relied more upon CSIRO's forecasts.

Our cost trajectory is shown below. Prices are currently higher in New Zealand reflecting the less developed market. We expect to remain more expensive than Australia, but for the margin to reduce over time.

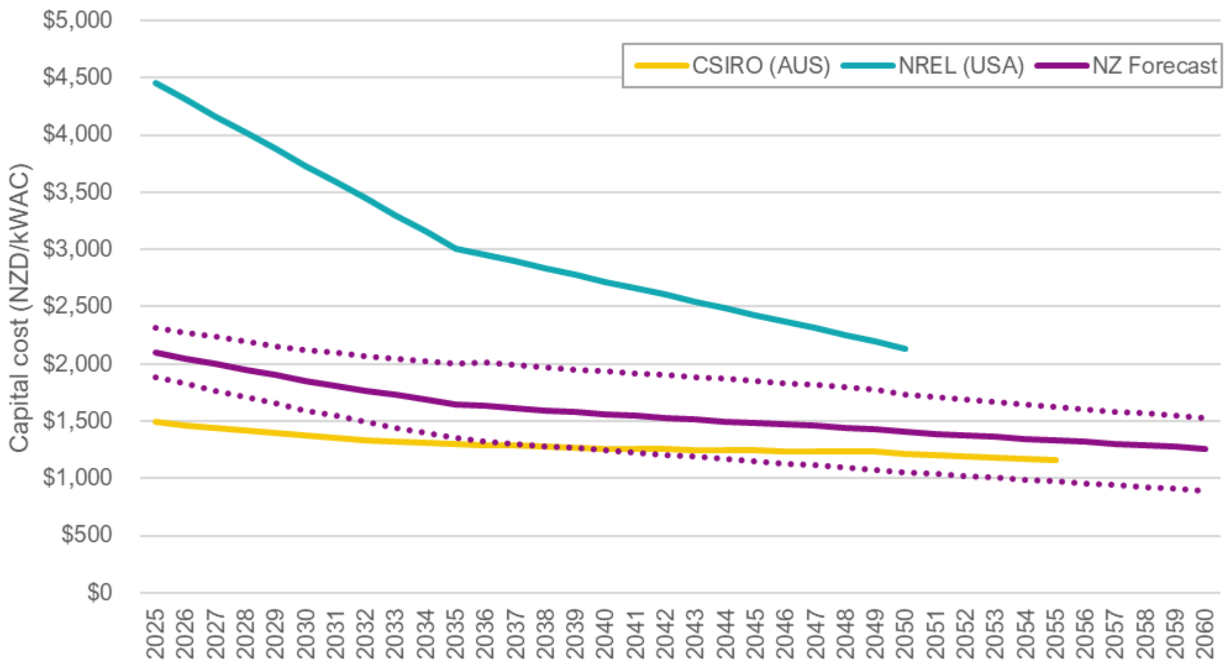

Figure 5-10 - Projected costs for rooftop solar

[11] Like all values in this report, this excludes GST. Note that prices advertised to the public in New Zealand must *include* GST, so the values shown here are not directly comparable to advertised prices.
[12] We have not included a cost range as it has less effect on modelling outcomes as we understand rooftop solar will be treated exogenously in Transpower's model.

5.4.4 Specific project costs

We do not expect there to be significantly different costs for rooftop solar in different parts of the country. Labour costs are one potential factor that might vary more than for other technologies, because labour costs make up a larger proportion of total costs, and unlike for grid scale projects, installers will be locally based. However, we are going into less detail for rooftop solar costs since they will not be endogenously built in Transpower's modelling. This may change in the future, and if so, we will investigate potential labour cost trends further.

5.5 Utility-scale Batteries

5.5.1 Current cost estimate

We have robust 2-hour battery cost data from three recent 100 MW battery development announcements by Genesis, Meridian and Contact.

All three battery projects are able to lean on infrastructure developed for other purposes, which helps to keep costs low. In the case of Genesis' battery at Huntly and Contact's battery at Glenbrook, this is by using existing electrical infrastructure originally developed for the Huntly power station and Glenbrook steel mill, respectively. Meridian's Ruakākā battery will be paired with a solar farm, so there are co-location benefits. Even so, the cost for the Ruakākā battery is higher than the other two options, and this may reflect the development of new infrastructure.

Our estimate for the 2025 cost of 2-hour batteries is 1,700 $/kW based on the average of Genesis' and Contact's batteries, adjusted to a 2025 basis. These projects are not "greenfield" projects because they are able to lean on existing infrastructure. However, we feel most other potential batteries would also be developed on a similar basis, so this is a reasonable starting point.

5.5.2 Cost trajectory

Our estimate of the current cost for utility scale batteries lies between the CSIRO and NREL current costs. It is closer to the NREL value, so we weight that cost trajectory more highly.

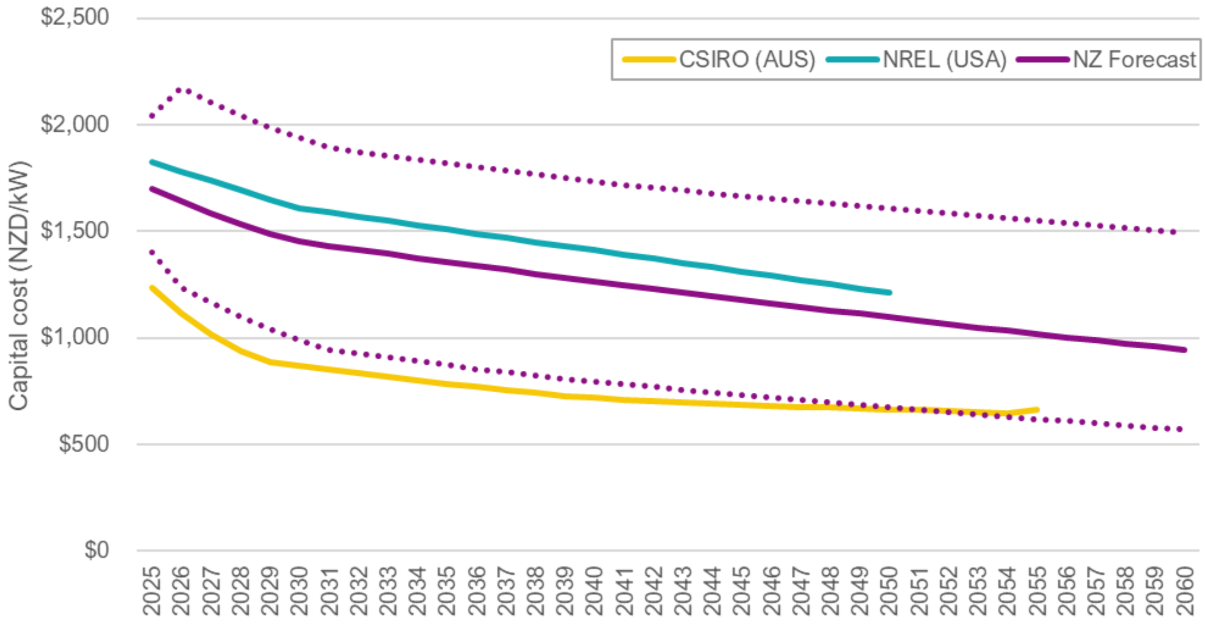

Figure 5-11 - Projected costs for 2-hour batteries

We also estimate costs for a 10-hour battery. While we do not have New Zealand specific costs for this, we use the 2-hour battery data and the 10-hour battery forecasts to produce an expected current cost level for 10-hour batteries in New Zealand and forecast accordingly.

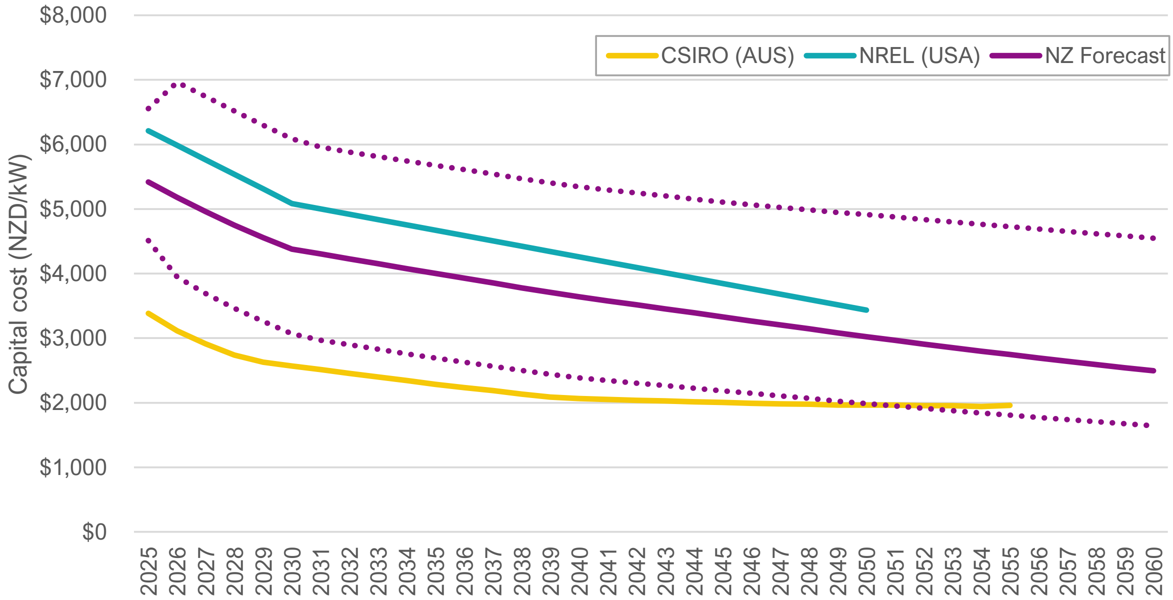

Figure 5-12 - Projected costs for 10-hour batteries

The high and low scenarios are significantly different from the base case. This reflects the underlying data, with NREL "high" forecasts for 2025 being 50% higher than their "low" forecasts. It is also appropriate to have very large variations between high and low forecasts for batteries, because they are a rapidly developing technology with intense international research focused on reducing costs.

5.5.3 Specific project costs

We do not see significant differences in costs for specific projects, and as such we use the same cost trajectory for all projects. This is because the relatively compact footprint of batteries allows them to be placed in relatively flexible locations, meaning that it is unlikely for a project to be built in a location that incurs site cost premiums.

5.5.4 Capacity related and storage related costs

We have presented values for 2-hour and 10-hour batteries, but battery costs can more generally be separated into a cost per kW (i.e. capacity related costs such as connection size) and a cost per kWh (i.e. storage related costs such as total number of battery cells). The cost per kWh component is forecast to fall significantly faster than the cost per kW component.

This is a reasonable approach to calculating total battery costs for different duration of battery storage and we include these values in the accompanying spreadsheet. The cost of a n-hour battery is the battery capacity cost (in $/kW) plus n times the battery storage cost (in $/kWh).

5.5.5 Operating and maintenance costs

We use the simple average of CSIRO and NREL values to estimate O&M costs as we do not have reliable O&M costs for New Zealand. Both CSIRO and NREL indicate that all O&M costs are on a fixed basis with no variable component.

5.6 Residential Batteries

5.6.1 Current cost estimate

Our estimate for current residential battery costs is based on a CSIRO value of AUD$13,500 for a 5kW/10kWh battery from 2024. [3] We adjusted this into 2025 NZD for a battery in 2025 in New Zealand[13] which resulted in a cost of 3,700 $/kW for a 2-hour battery. This value is consistent with currently advertised prices in New Zealand.

5.6.2 Cost trajectory

We applied the absolute cost reductions estimated for grid scale batteries. This replicates the approach used by CSIRO.[14]

5.6.3 Operating and maintenance costs

Similarly to residential rooftop we assume that the capital cost includes a warranty which covers operating and maintenance costs.

5.7 Geothermal

5.7.1 Current cost estimate

New Zealand is a global leader in geothermal due to our abundant resources and long history of development.[15] On average, reported costs for projects are significantly lower than global benchmarks.

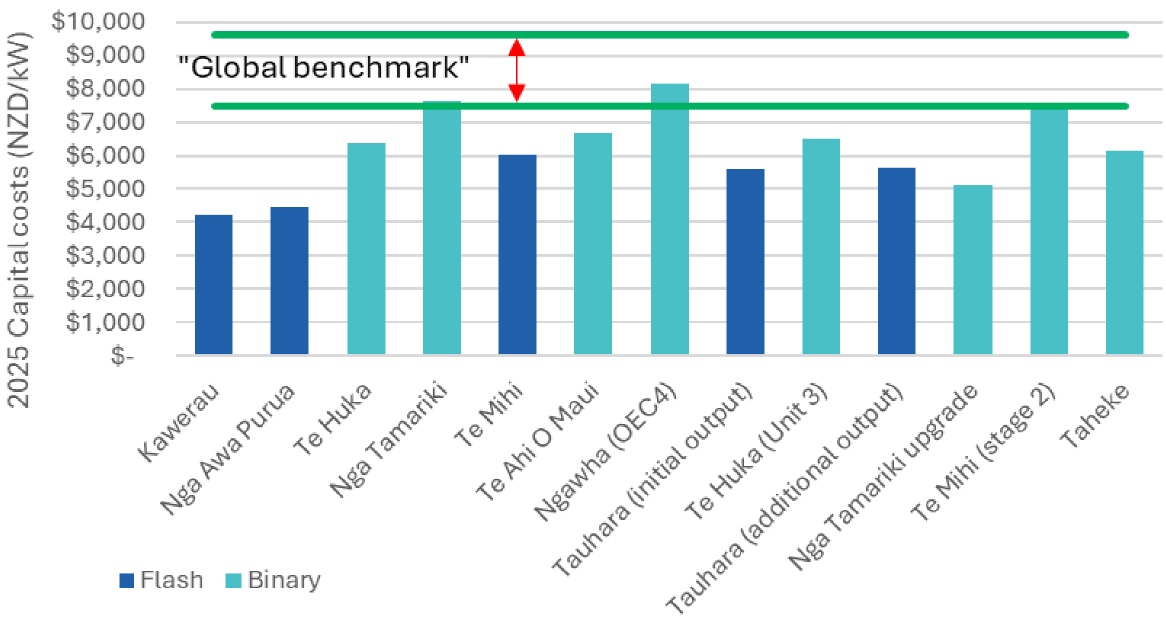

Figure 5-13 - Geothermal costs

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[13] This involves converting from AUD to NZD, adjusting for inflation, adjusting for a reduction in battery costs over time, and, finally, applying an uplift for the cost in New Zealand relative to Australia. We used an uplift of 20%, which is based on the cost difference seen for larger batteries and residential solar.

[14] "That is, we calculate the premium for small-scale batterie [sic] and maintain that premium when drawing on the large-scale battery projection." – Resource [4].

[15] Wairakei power station was opened in 1958 and was the second power station in the world to utilize geothermal steam.

Figure 5-13 shows completed and proposed geothermal project costs as well as a reference global benchmark [8]. There is a large range of project costs, but they also span two decades of development. Projects are shown in chronological order, from Kawerau (developed in 2008) to Taheke (proposed for development in 2028). Te Ahi O Maui was developed in 2018, and we consider it, and anything developed after it to be "recent".

5.7.2 Previous MBIE reports

MBIE's 2020 geothermal stack report [16] is a high-quality report that outlines and explores the key factors that influence geothermal project costs.

More so than the other technologies included in the MBIE generation stack (which have experienced significant market disruption and development in the past five years) the report remains highly relevant today and should be reviewed by anyone interested in geothermal costs and resources in New Zealand.

One difference that we adopt in this report is to place less effort on estimating precise forecasts for each individual project. However, the supply stack included in the MBIE report remains a relevant resource for this purpose.

More recently, MBIE released "From the Ground Up" [17], a draft strategy to unlock New Zealand's geothermal potential. This has the goal of doubling geothermal energy use by 2040. One of the steps to enable this is to improve access to geothermal data and insights, and we anticipate that the information in this document will further this goal.

5.7.3 Potential cost influences

5.7.3.1 Greenfield vs Brownfield

We investigated whether distinguishing between greenfield and brownfield projects had a large effect on capital costs. Our first insight is that there is not a clear dichotomy between greenfield and brownfield sites for geothermal. Often steam from an existing field is used to fuel an otherwise greenfield development. Although there are no savings on plant costs, total development costs and risks are lower because the resource is well established, and developers may have previously worked with relevant landowners.

Taking this into account, we still could find no clear distinction. For example, Te Huka unit three has similar costs to the initial development, and Te Mihi Stage 2 is more expensive than the original.

5.7.3.2 Plant technology type

Potentially more important is the difference in technology type between binary and flash plants. Binary plants reinject geothermal fluid and use a secondary fluid to operate turbines. This setup minimizes emissions. Alternatively, in a flash plant, geothermal fluid is used to turn turbines directly, and capturing emissions with this setup is much more difficult. There appears to be a trend towards binary plant in more recent years, and this may reflect the impact of the Emissions Trading Scheme. Reinjecting non-condensing gases is significantly easier with binary plant.

There is some evidence of a systemic price difference between binary and flash plants. In Figure 5-13, binary plant is shown by light blue, and flash by dark blue. A useful comparison point is Tauhara (a flash plant) and Te Huka Unit 3 (a binary plant). Both operate on the same field and were developed by the same party. The binary plant development was about 900 $/kW higher (about 16%), which supports binary plant having a cost premium. However, NREL's price premium for binary compared to flash is about 29%, which is significantly higher.

We adopt an assumed priced premium of 20% for binary plant. Geothermal projects are highly unique, so costs from one pair of projects will not be indicative of the average difference. However, given the wide spread of costs for binary and flash plant, and that many binary plants are cheaper than other flash plants, we think NREL's spread of 29% seems slightly too high.

Taking the average of all recent plant, and applying the binary premium, we determine the current cost of geothermal as 5,600 $/kW for flash and 6,700 $/kW for binary.

5.7.3.3 Enthalpy of thermal resource

Two additional factors were highlighted in the previous MBIE generation stack report [16]. The first of these is field enthalpy.[16] A higher enthalpy reservoir should have lower capital costs because energy can be more easily extracted from the geothermal fluid and vice versa.

Most fields that could be developed were classified as "medium", with the notable exception of Ngāwhā in Northland, which was classified as "low". The MBIE report indicates that a cost multiplier of 1.3 should be applied to low enthalpy sites. In practice, it appears that Ngāwhā developments have cost roughly 1.2 times the "typical" geothermal cost. Applying a 1.2x cost factor is consistent with observed cost data and the first principles approach outlined in the MBIE report. Such a factor is appropriate to use for Northland geothermal, given that all Northland development in the foreseeable future will be on the Ngāwhā field.

5.7.3.4 Project size

Another feature that may influence geothermal project cost is project size. MBIE's previous generation stack estimated that 40% of costs did not scale linearly with project size, and produced the following cost curve,

Figure 5-14 - Previously estimated cost vs size curve

Figure 5-14 indicates that a 100 MW project will cost about 20% less than a 50 MW project.

[16] Enthalpy is a measure of the energy content in the reservoir steam. Hotter, higher-pressure steam has higher enthalpy and more extractable energy.

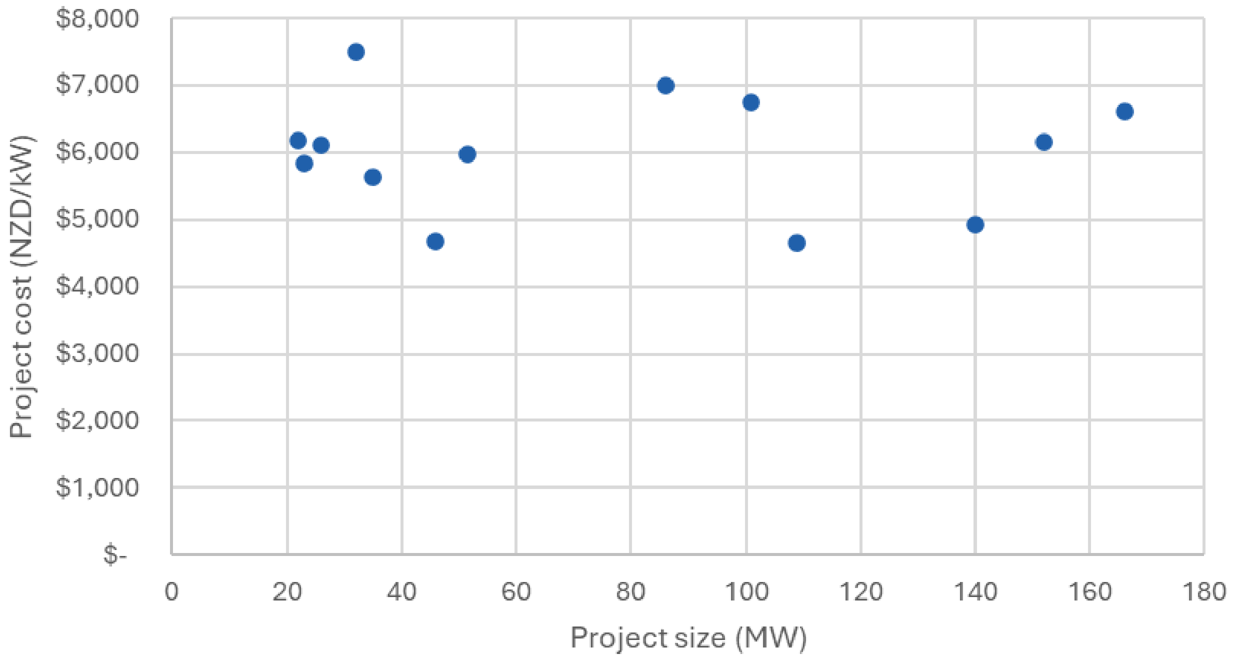

Figure 5-15 - Historical project cost vs project size

However, such a relationship is not obvious from observed project costs. Figure 5-15 shows reported costs[17] and project size for completed projects in New Zealand. There is no clear relationship between size and cost, despite project size ranging from slightly over 20 MW to more than 150 MW.

Given this, and our previous comments on economies of scale and project size, we have not included project size as an indicator of project cost for geothermal.

5.7.4 Cost trajectory

We adopt a different approach for forecasting geothermal costs. CSIRO does not produce geothermal costs because there is no relevant geothermal resource in Australia. NREL produces separate binary and flash cost forecasts. However, as observed above, New Zealand geothermal is world class, more developed and already significantly cheaper than global benchmarks.

As such, we forecast geothermal costs using our standard mature learning rate (0.35% pa). This is much shallower than early NREL forecasts, but more similar from the mid-2030s (NREL uses a year-on-year learning rate of ~0.5% from this period onwards.)

We also believe a lower learning rate is appropriate because of the decline in the oil and gas industry in New Zealand. Similar drilling machinery and technology is used in both industries, and if the oil and gas industry diminish, this will put upward pressure on geothermal development costs.

[17] Costs are adjusted to 2025 equivalent and include a cost adjustment for binary vs flash technology type.

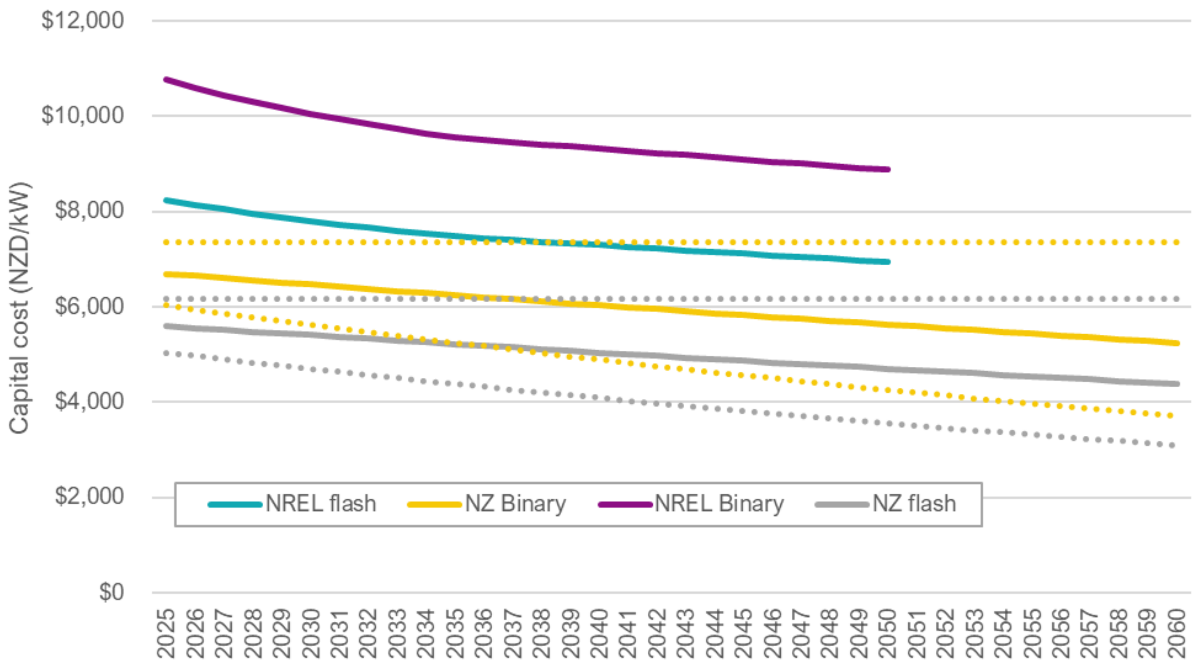

Figure 5-16 - Projected costs for geothermal

5.7.5 Specific project costs

We do not provide specific project costs but instead recommend a regional specific cost for a generic project. Our "typical" cost curve applies to projects in the Central Plateau and Bay of Plenty. Projects in Northland should incur a 1.2x cost multiplier relative to our typical cost due to lower resource enthalpy.

We have not separated our generic regional geothermal costs into specific projects. Resource size/quality and electrical connection considerations will tend to determine the optimal build size. Accounting for these effects is complex and requires identifying spare capacity on each geothermal resource. We have not done this for this project, but this is an area that could be explored further in future generation stack updates. The previous MBIE report did undertake this process and remains a useful resource, although we note that they did not appear to consider connection costs.

5.7.6 Operating and maintenance costs

O&M costs for geothermal can be expressed exclusively as FOM costs. Geothermal plant output is not varied according to market conditions. The "fuel" is essentially free so there are no fuel savings from reducing output, and, more importantly, reducing steam offtake can reduce future steam availability. Accordingly, geothermal generation is very reluctant to lower output.

Contact published FOM values in a 2022 publication [8] which equate to ~160 $/kW/yr and we have used this as our estimate for New Zealand. For O&M cost trajectories we use our mature learning rate of 0.35% pa.

The previous generation stack estimated geothermal fixed O&M at 190 $/kW/yr (2020 dollars). Our value of 160 $/kW/yr is broadly consistent with this.

5.8 Underground Gas Storage

5.8.1 Background

Although it is technically a fuel storage technology, this report also considers the costs of underground gas storage (UGS). UGS is highly dependent on having an appropriate underground resource. New Zealand has one currently operational UGS field (Ahuroa) and one potential site that is currently under investigation (Tariki). We consider the costs of developing or expanding these two fields, and do not look at a "generic" gas field.

UGS can be characterized by two main parameters – the total storage capacity of the field (i.e. the size of the tank) and the throughput of the field when injecting or extracting gas (i.e. the size of the tap). The rate of injection and extraction need not be identical but are often similar.

5.8.1.1 Ahuroa

Ahuroa was initially developed by Contact from 2008-2010. The facility was sold to First Gas in 2018.

Initial working capacity was stated as ~18 PJ, but that has been revised down multiple times and currently stands at 7 PJ. Initial throughput was 45 TJ/day extraction and 27 TJ/day injection. This was upgraded by First Gas in 2020 to 65 TJ/day injection and extraction.

First Gas released limited information on the cost of this upgrade, but Contact had previously published their estimate of the cost to upgrade the facility by 50 TJ/day, and we use this as the typical cost of upgrading UGS throughput.

Contact also stated in 2015 that total throughput could increase to 170 TJ/day if needed. However, it is possible that maximum potential throughput may have been reduced as total working storage value has been reduced.

5.8.1.2 Tariki

Tariki is a neighbouring field to Ahuroa, and Genesis has been involved in developing it into an UGS facility. No date for operation has been published, but the project is expected to take 18 months to develop, and given the need to fill storage before drawing upon it, we do not expect it to be available for extraction before winter 2027 at the earliest.

We have limited cost data on the Tariki development. A statement by NZ Energy Corp in 2022 indicated that it could be developed for approximately $110M. It is likely that this figure was an optimistic early estimate and represents a lower bound. The field would have throughput of 25 TJ/day at this cost.

5.8.2 Current cost estimate

We do not provide a cost for upgrading working storage for Ahuroa or Tariki. The size of the storage capacity is largely determined by geographic features and cannot be easily increased. Also note that storage capacity at Ahuroa has been *decreasing* over time, likely due to water ingress in the facility.

However, throughput *is* much more amenable to upgrading. Our estimate for upgrading throughput is identical for both facilities, given that most costs are asset related, and the two fields have similar geological features. The value published by Contact in 2015 equates to roughly $100M per 50 TJ/day of throughput in 2025 dollars. This is consistent with the stated value to develop Tariki.

Indicative costs are also provided by AEMO [15]. They suggest that the cost to develop a new UGS is about 230m NZD for a 100 TJ/day facility. They also suggest that the cost to increase capacity from 100 TJ/day to 200 TJ/day would be roughly 60% of this, or about 140m NZD. These values are consistent with our Contact sourced estimate.

We have assumed that this cost will decrease over time by our mature learning rate of 0.35% pa.

5.8.3 Operating and Maintenance costs

O&M costs for underground storage are primarily compressor gas costs. A portion of gas that is supplied to the facility to be stored is instead used to operate compressors that are needed to pump gas underground. The gas used is typically a few % of gas stored. We suggest a value of 2% as a reasonable estimate. The value of this gas will depend on the value of gas in the wider model and is highly variable.

In addition to compressor gas, the facility will incur standard "wear and tear" costs. We were not able to find any reliable sources to provide indicative costs for this value but suggest that a guideline fixed annual O&M cost is about 3% of total capex.

5.9 Thermal

5.9.1 Background

New Zealand has a relatively small number of thermal generators and limited recent experience with new installations.

The following thermal generation types have been considered:

- Combined Cycle Gas Turbine (CCGT) – including with Carbon Capture, Utilisation and Storage (CCUS)
- Open Cycle Gas Turbine (OCGT) – including with CCUS
- Rankine Cycle – including with CCUS
- Reciprocating Engine

5.9.2 Cost estimate and cost trajectory

Given the limited amount of available New Zealand data, price forecasts from Australia and overseas have been used to derive the price forecasts for thermal technologies. Price trajectories have also been included for options both with and without carbon capture.

Cost estimates for thermal generation technologies incorporating carbon capture were sourced from various references, each applying specific escalation rates to reflect inflationary trends. Currency conversions were applied where necessary to align all values with NZD.

For CCGT data we have utilized data from CSIRO, NREL, and the previously produced MBIE stack. The learning rate applied is in line with the rate used by CSIRO. However, it is noted that there is presently a heightened global demand for gas turbines, with lead times out to 2030. This means that the present projections show a short-term elevated cost which reduces until 2030, at which point it remains relatively the same for the forecast period. The current cost estimate for CCGT for the purpose of this report is 2,400 $/kW. The cost trajectory is the base line shown in Figure 5-17.

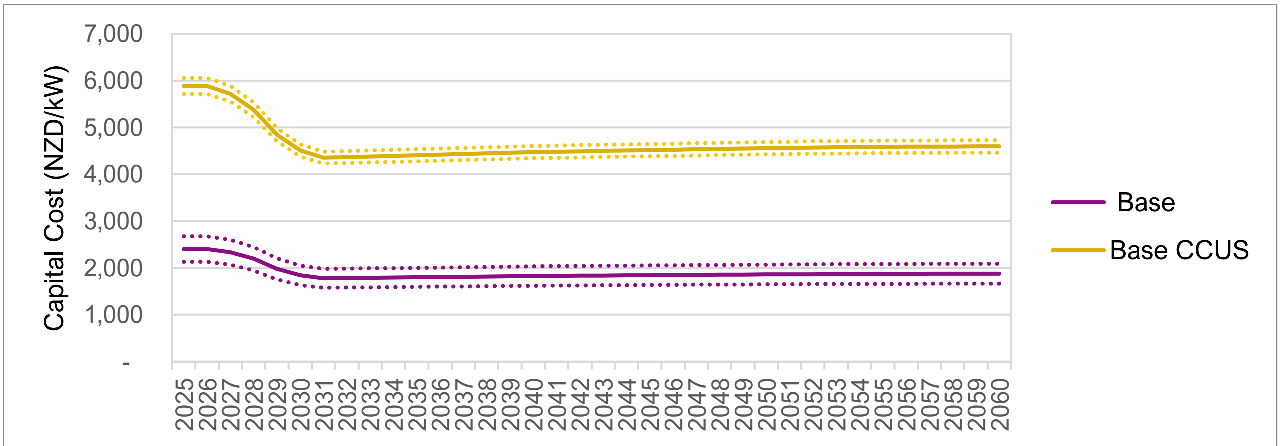

Figure 5-17 - Thermal CCGT Cost Trajectory

For OCGT data we have utilized data from CSIRO, NREL, and the UK Department for Energy Security and Net Zero. The learning rate applied is in line with the rate used by CSIRO, but it is noted that there is presently a heightened global demand for gas turbines, with lead times out to 2030. As for CCGT, this means that the present projections show a short-term elevated cost which reduces until 2030, at which point it remains relatively the same for the forecast period. The current cost estimate for OCGT for the purpose of this report is 2,400 $/kW, it is noted that this is similar in the cost allocated for CCGT; it is understood that this is because of short term supply and demand factors and by 2030 OCGT is expected to be cheaper than CCGT again. This cost estimate is based upon a 100 MW peaking plant. It is noted that significant economies of scale can be realized with OCGT technology with respect to capital cost, and a larger plant (>300 MW) could have a reduced capital cost of up to 50% (although efficiency remains relatively the same). However, it is expected that given the size of the New Zealand power system a peaking plant of 200 MW or less is more likely. The cost trajectory is as shown in Figure 5-18.

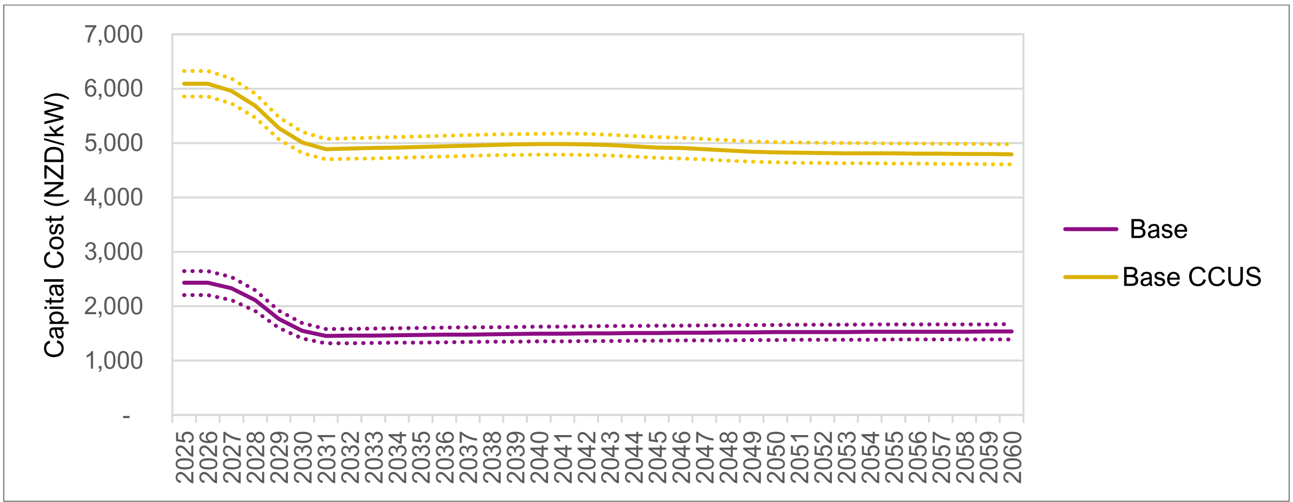

Figure 5-18 - Thermal OCGT Cost Trajectory

To assess Rankine Cycle and Reciprocating Engine generators, the primary source was CSIRO, with NREL used for cross-verification. The cost estimates from both sources were found to be in a similar range. The learning rate from CSIRO has been adopted for both of these and is minimal due to the mature nature of the technologies. The current cost estimate for a Rankine Cycle plant is 6,300 $/kW, and it is 1,700 $/kW for Reciprocating Engine plant. The cost trajectories for these are shown in Figure 5-19 and Figure 5-20 respectively.

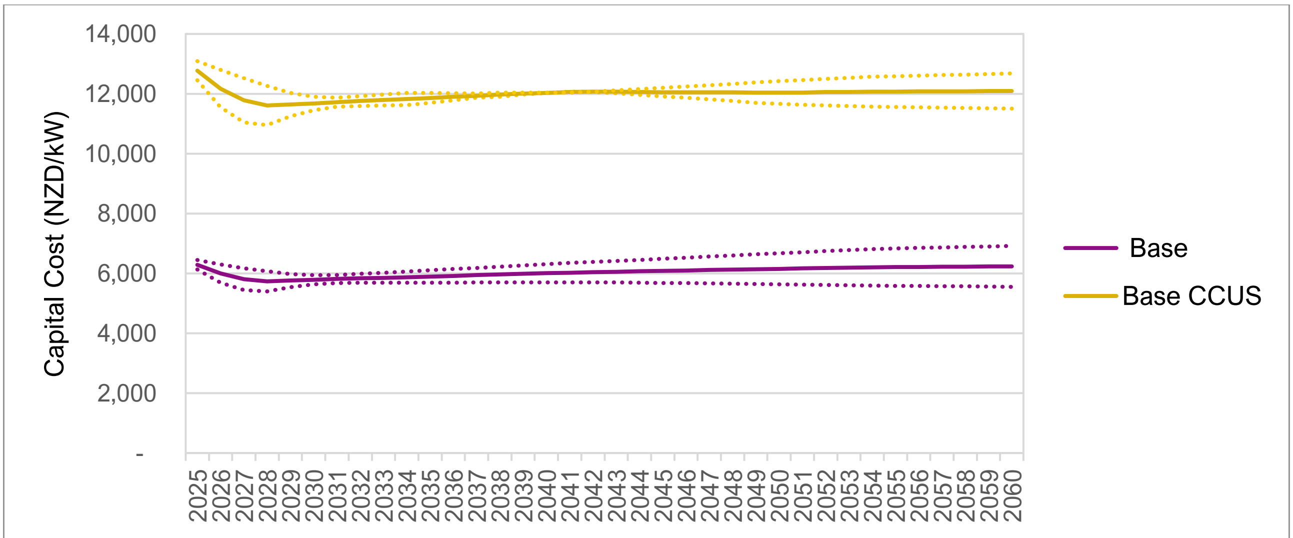

Figure 5-19 - Rankine Cost Trajectory

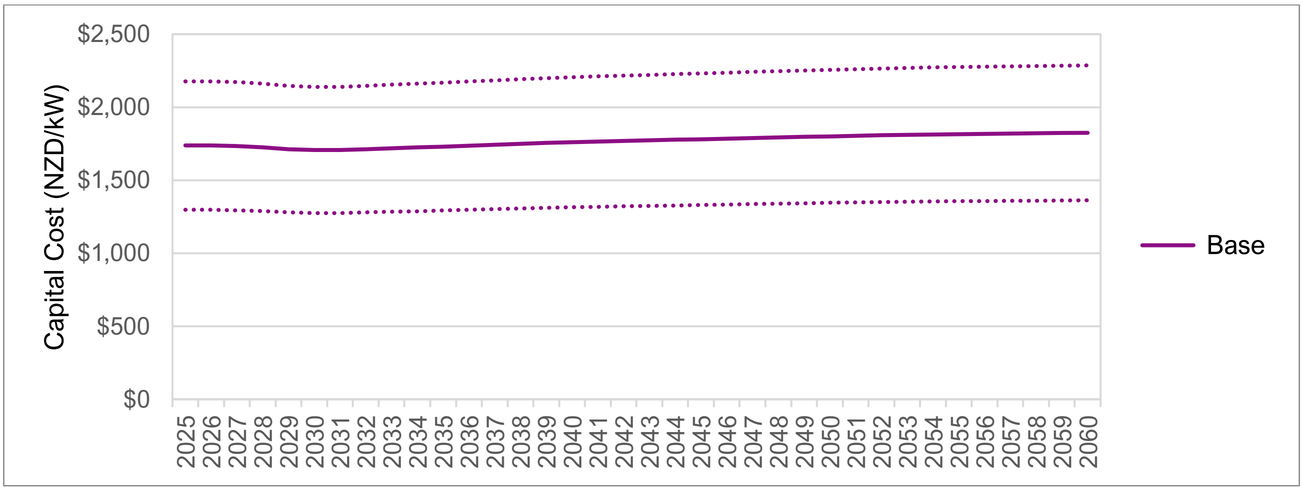

Figure 5-20 - Reciprocating Engine Cost Trajectory

Carbon capture has also been considered separately for CCGT, OCGT, and Rankine Cycle plants, from the same sources as the non-carbon capture versions. In general, the carbon capture version of a given thermal generation type is 2-3 times the price of the non-carbon capture version. This is consistent with data provided for carbon capture rates between 90% and 95% [9]. The current cost estimate for a carbon capture rate around this level is 5,900 $/kW for CCGTs, 6,100 $/kW for OCGTs, and 12,800 $/kW for Rankine Cycle plant. These costs do not allow for costs associated with sequestration or long-term storage of carbon. There is a commercial market for CO_2 gas, therefore it is possible that captured carbon could be used as a revenue stream and not require sequestration.

It is noted that there is limited international experience at present of thermal generation with carbon capture and storage with only two known commercially operating plants, and approximately eight under construction worldwide according to the IEA CCUS project database.

5.9.3 Thermal technology parameters

The thermal generation costs have been based on the following generic plant assumptions:

Table 5-1 – Thermal generation plant parameters

Technology	OCGT	OCGT + CCUS	CCGT	CCGT + CCUS	Reciprocating	Rankine	Rankine + CCUS
Fuel	Gas	Gas	Gas	Gas	Gas	Coal	Coal
Capacity, MW	100	85	350	300	100	700	620
Number of Units	3	3	1	1	6	3	3
Heat Rate (Max Output) GJ/GWh	10,100	14,400	6,600	8,800	7,900	8,600	11,600

It is noted that the OCGT heat rate is higher than that of the current Stratford units, however, based on the relatively small capacity selected, this is consistent through the sources used. Larger OCGT units generally provide greater efficiency than smaller ones. It is also noted that the Rankine heat rate is lower than that of the existing Huntly units, this is due to the expected efficiency gains from newer units.

5.9.4 Specific project costs

No specific projects have been considered, as at the time of writing there was no specific project data available. It is, however, noted, that a significant factor for any thermal technology will be access to its fuel source, and the fuel aspect is not considered as part of this report.

5.10 Hydroelectric

5.10.1 Background

Hydroelectricity is well established in New Zealand and internationally, however, no significant new projects have been built in New Zealand for several decades. Additionally, it is noted that hydroelectric project costs are very difficult to predict, as they are heavily influenced by site specific factors. Given the lack of recent project experience in NZ, data has been sourced exclusively from international sources.

5.10.2 Cost estimate

To estimate the cost for hydroelectric projects we have utilised data from the UK Government's "Electricity Generation Costs 2023" report [4] as well as the International Energy Agency's "Projected Costs of Generating Electricity 2020" [10]. The costs presented by these two reports when converted are 9,000 $/kW, and 9,400 $/kW respectively. Our estimated present-day cost is therefore 9,200 $/kW. This is a significant increase in comparison to the 2011 MBIE generation stack report, which presents costs in the order of 5,900 $/kW when converted to 2025 dollars. Additionally, NREL presents costs in the order of 13,500 $/kW. The level of variability between sources highlights the level of uncertainty associated with estimating hydroelectric projects, and the selected value of 9,200 $/kW sits in the middle of the range.

5.10.3 Cost trajectory

Hydroelectricity is a mature technology; we have therefore applied a mature technology learning rate of 0.35% pa. The cost trajectory is as shown in Figure 5-21.

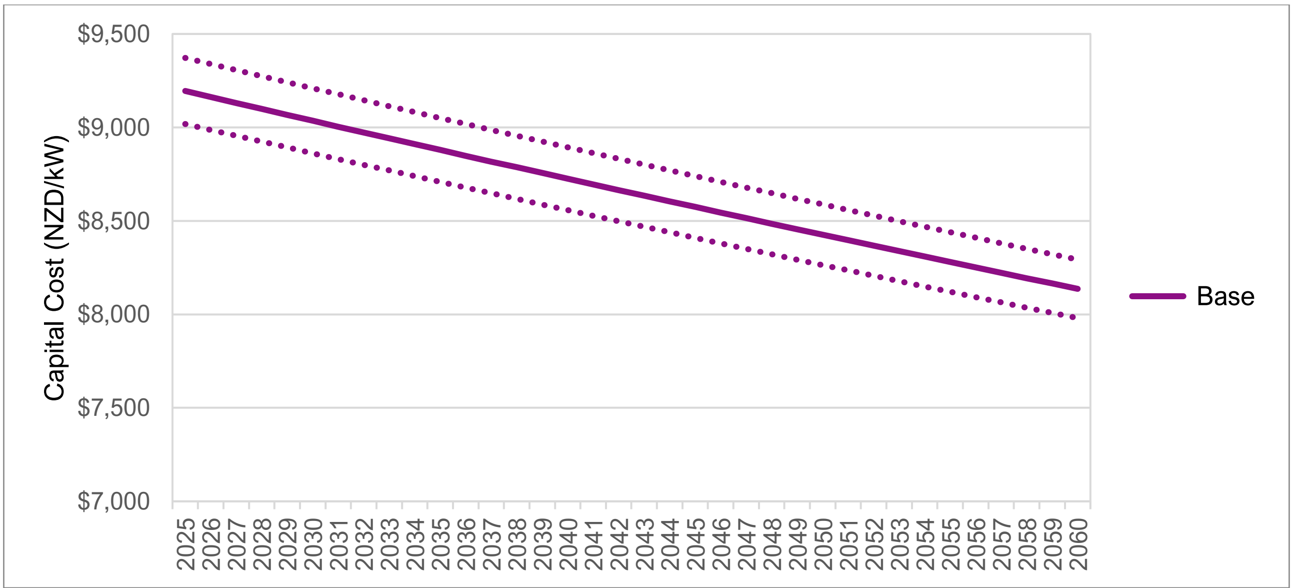

Figure 5-21 - Hydroelectric Cost Trajectory

5.10.4 Specific project costs

No specific projects have been considered, as at the time of writing there was no specific project data available. However, as noted any real project costs will be heavily site dependent.

6 Potential Technologies

6.1 Offshore Wind

6.1.1 Background

Offshore wind is a similar technology to onshore wind but located out at sea. Both capture the kinetic energy of the wind using large blades to spin a turbine and generate electricity.

Offshore wind turbines are typically fixed to the ocean floor. This can be done in a variety of different ways (e.g. monopile, jacket structure or gravity base). However, some developers are looking at floating platforms that are tethered to the seafloor with cables.

Compared to onshore wind, offshore wind farms have three particularly distinctive features:

1. **Large scale** – offshore developments face fewer barriers from topography[18] or impact on amenity. They are therefore easier to consent and build at a greater scale than their onshore equivalents (both through larger turbine size and number of turbines).

2. **More expensive** – offshore developments require more materials and more specialist equipment and expertise than their onshore equivalents. They are also likely to be located further from the grid. As such, they tend to have higher costs (on a per kW basis), as noted further below.

3. **Generally stronger wind resource** – offshore developments tend to have a higher capacity factor than their onshore equivalents (i.e. they operate at a higher percentage of their installed capacity for more of the time – see Figure 6-1 below).

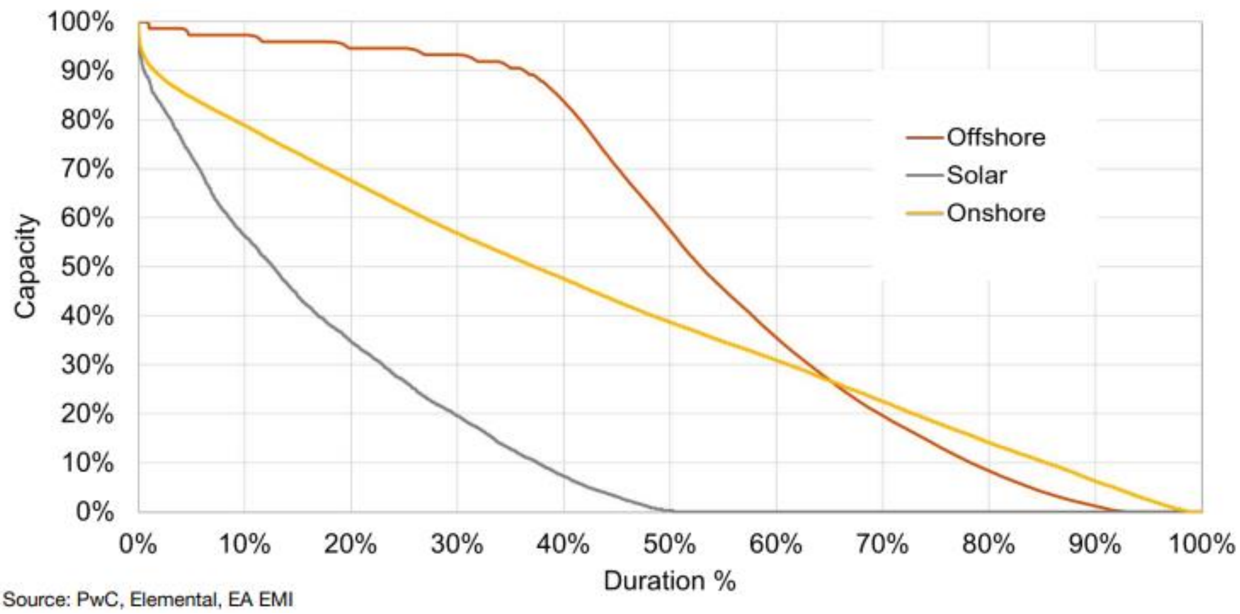

Figure 6-1 - Capacity duration curve - wind and solar [12]

Offshore wind is well established overseas. There was around 83 GW of offshore wind capacity globally at the end of 2024, mostly in China and Europe, having grown by around 8 GW that year [13]. Most of this capacity comes from fixed offshore wind, with floating wind farms making up less than 1% of new capacity

[18] Fixed-base offshore wind farms are still limited by seabed depth, but do not face other topographical constraints such as road access.

commissioned in 2024.[19] The first floating wind farm, with five turbines totalling 30 MW, was established in Scotland in 2017.[20]

No offshore wind farms have been developed in New Zealand at this stage. However, in recent years there has been interest in offshore wind by multiple developers. Several projects are being considered, generally in the South Taranaki Bight or off the western coast of Waikato.

However, there are still obstacles facing the development of offshore wind that make it only a prospective technology in New Zealand:

- There is no existing regulatory regime for the development of offshore wind. The government has introduced the Offshore Renewable Energy Bill, which would cover feasibility permits, commercial permits, decommissioning requirements, etc. This is yet to be fully implemented, but MBIE notes that the first feasibility permits should be granted in 2026. [21]
- Most overseas offshore wind developments have had some kind of price guarantee from the government, such as ‘contracts-for-difference’. However, the New Zealand government signalled in 2024 that it does not intend to offer such price support, and that it “expects offshore renewable energy projects to compete on the same commercial basis as other electricity generation.” [20]
- Lumpiness of investment. Offshore wind farms are typically much larger than onshore developments and this is difficult in a small market like New Zealand. For example, Taranaki Offshore Partners propose an initial 1 GW project that could be expanded to 2 GW later. A 1 GW wind farm would generate about 4 GWh of energy, or more than two years of demand growth. Integrating offshore wind into a market the size of New Zealand is difficult because we would either have undersupply before any project is completed, or oversupply after it is completed. An additional complication is that a 1 GW wind farm would be the “risk setter” on the grid and would need additional connection assets to ensure system security while it is operating.

The effect of these obstacles is evident in the decision of BlueFloat Energy, a potential offshore wind developer, to exit the New Zealand market in 2024, citing “a number of key uncertainties about how the market for offshore wind will develop in the country – including both route to market and allocation of seabed”.[21]

6.1.2 Current cost estimate

We set our “current” cost estimate for fixed offshore wind for the year 2030, as we do not consider it feasible for any projects to be commissioned in New Zealand before that date.

This cost estimate is based on a combination of overseas estimates, as well as indicative public estimates for potential New Zealand projects.

[19] 41.8 MW [13]
[20] Hywind Scotland - the world’s first floating wind farm - Equinor
[21] Offshore wind developer pulls out of NZ amid seabed mining concerns - Newsroom

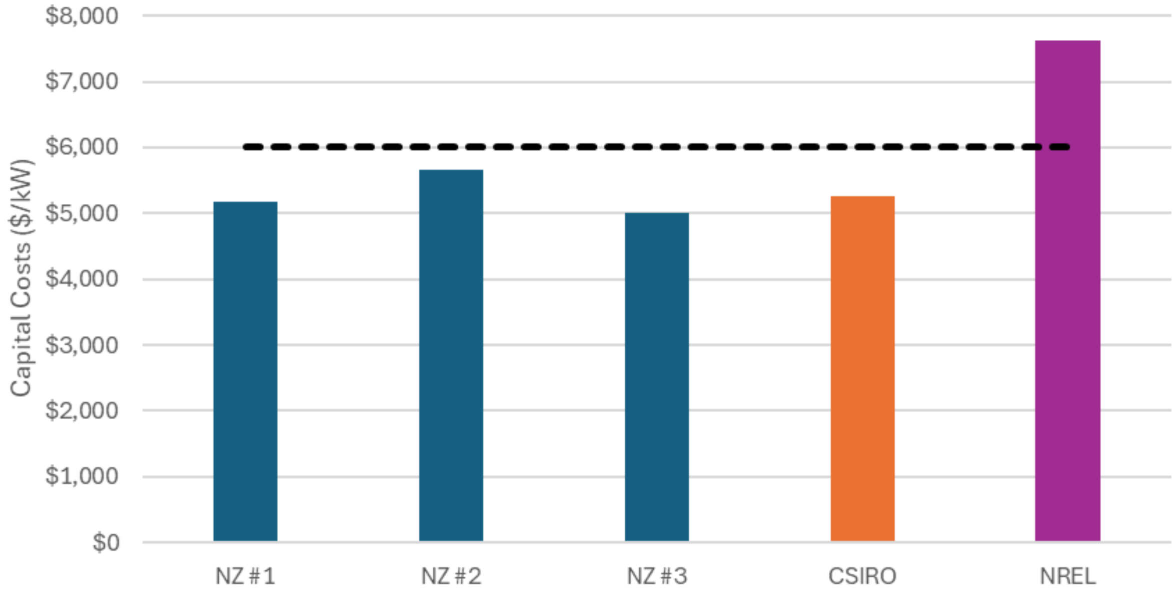

Figure 6-2 - Estimate of fixed offshore wind costs in 2030

CSIRO estimates a cost of NZ 5,259 $/kW for fixed offshore wind development in Australia completed in 2030. Like New Zealand, Australia's offshore wind industry is still developing, with no offshore wind farms operational at this stage.[22]

Offshore wind in the United States is slightly more established, with 174 MW of capacity from three relatively small offshore wind farms at the end of 2024 [13].[23] Interestingly, however, NREL estimates a higher cost of NZ 7,614 $/kW for fixed offshore wind projects in the United States completed in 2030.

Because New Zealand offshore wind developments are all still at very prospective stages, there is limited New Zealand-specific cost information. Various estimates for 1 GW of offshore wind in New Zealand appear to report figures between $5.2 and $5.7 billion (depending on the source) – i.e. around 5,500 $/kW. This figure is similar to but slightly higher than the CSIRO estimate, which is unsurprising due to Australia's similar geographical location and still emerging (but slightly more advanced) offshore wind industry. However, due to the materially higher NREL estimate, and the tendency for early cost estimates to underestimate the final delivered cost, we consider it appropriate to use a slightly higher current (i.e. 2030, given that this is the earliest date that a project could be completed) cost estimate of 6,000 $/kW for New Zealand projects.

The costs above are for fixed offshore wind, as this is what prospective developers in New Zealand have been investigating. We also include costs for floating offshore wind, but international cost curves suggest that it would be significantly more expensive than fixed offshore wind.

However, this assumption should be revisited in the future, particularly once exclusivity licences are granted. Many of the prospective project sites overlap, so interest in floating turbine technology may increase as fixed turbine sites become unavailable.

[22] However, it is still at a more advanced stage than New Zealand's very nascent industry – for example, Australia has awarded feasibility licences in the Gippsland offshore wind areas for a total of 25 GW of capacity [13].
[23] Note that this capacity figure excludes the Vineyard Wind 1 project, which began exporting from some turbines in early 2024 but paused operations when a turbine blade breakage occurred. The 806 MW project is expected to be fully commissioned by the end of 2025.

6.1.3 Cost trajectory

Offshore wind costs are expected to come down over time. Much of this is expected to happen prior to our forecast beginning in 2030 (particularly under NREL's estimates), but material cost reductions are still expected over the next few decades.

For our forecast, we assume a cost trajectory based on the average learning rates of the CSIRO and NREL forecasts, weighted based on the proximity of our starting 2030 estimate to the relative curves (i.e. towards the CSIRO trajectory).

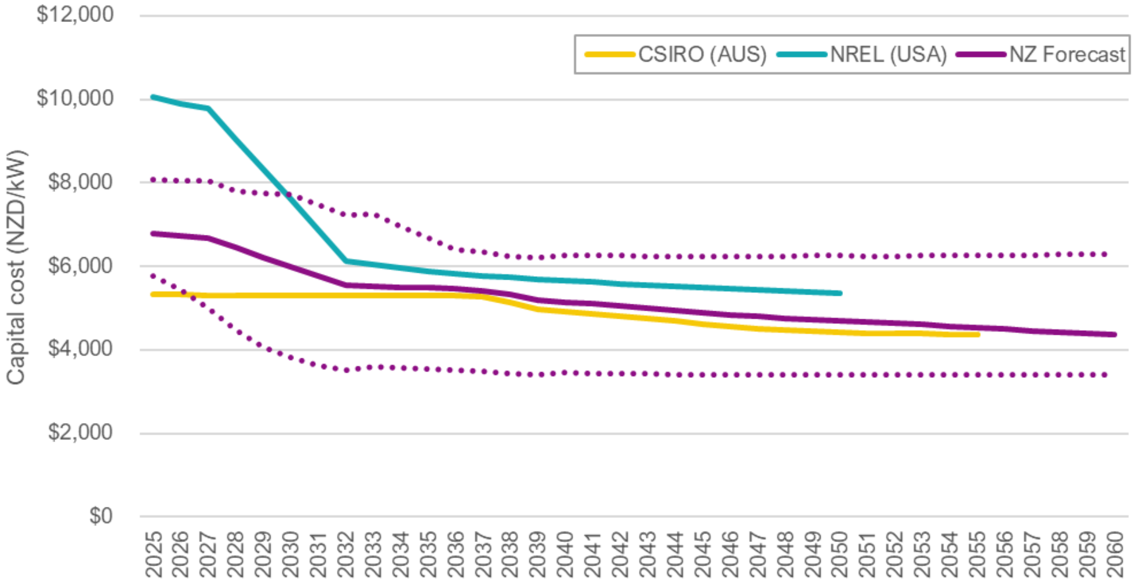

Figure 6-3 - Projected capital costs for fixed offshore wind

This results in projected fixed offshore wind costs falling to around 4,400 $/kW by 2060.

We also forecast floating offshore wind costs, although these have a higher level of uncertainty given the lack of development in New Zealand. Costs are significantly higher than fixed offshore wind for 2030 (using the midpoint of the CSIRO and NREL forecasts) and remain higher over the forecast period. Data is not available for prior to 2030 in some source material.

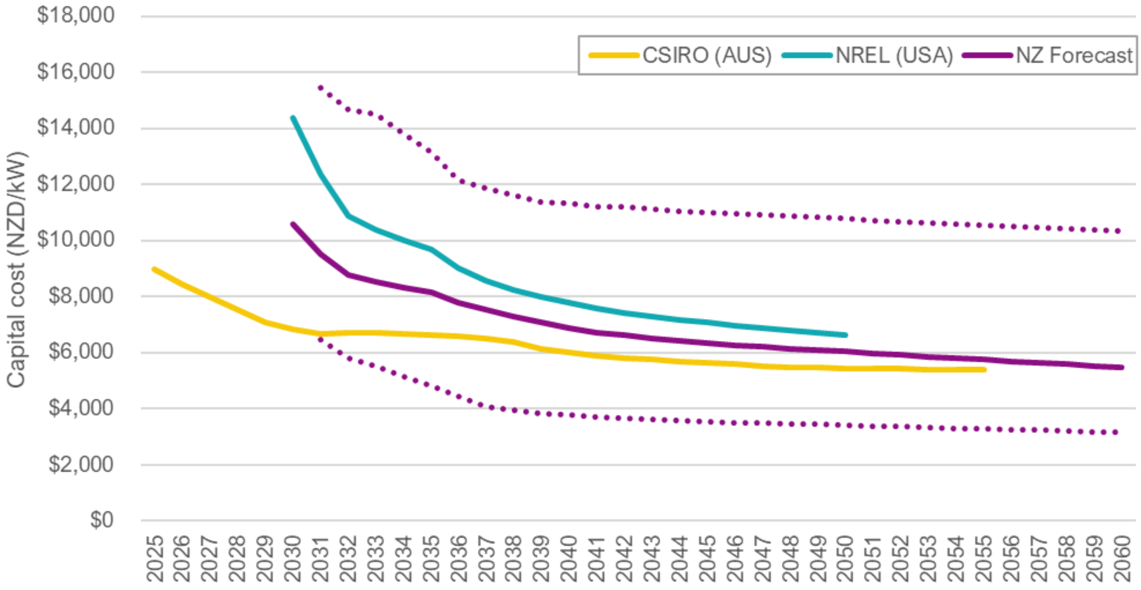

Figure 6-4 - Projected capital costs for floating offshore wind

6.1.4 Other technical information

As noted in Figure 6-1 above, capacity factors for offshore wind can be significantly higher than onshore wind. When using these projects in modelling, an appropriate wind resource data series should be used.

6.1.5 Operating and Maintenance costs

We have used the simple average of CSIRO and NREL O&M costs for both fixed and floating offshore wind. Both CSIRO and NREL indicate that all O&M costs are fixed.

6.2 Concentrated Solar Power

6.2.1 Background

Concentrated solar power (CSP) utilizes mirrors to reflect sunlight and heat a fluid. This fluid is subsequently used to turn a turbine and generate electricity.

The main advantage of CSP over regular solar power is that the heated fluid can be stored and used to generate electricity while the sun is no longer shining. This is very useful for meeting evening peak demand.

There are no CSP plants currently operating in New Zealand, but a combined 8.1 GW was operating overseas as at 2023.

6.2.2 Storage duration

CSP can be categorised both by a capacity value (MW) as well as a storage duration. CSIRO assumes a storage duration of 16 hours. NREL assumes a storage duration of 10 hours. Note that although CSIRO assumes a longer storage duration, it has a lower cost estimate. Given the large uncertainty in costs, we are not overly specific in our assumed storage duration but suggest that our values are applicable to a CSP plant with 10-16 hours' storage duration.

6.2.3 Cost estimate and cost trajectory

Both CSIRO and NREL produce price forecasts for CSP, and we have used these to determine a cost for New Zealand. We have used the simple average of the two. It may be arguable to assume a higher cost for New Zealand, but given the underlying uncertainty in cost estimates we believe a simple average is reasonable.

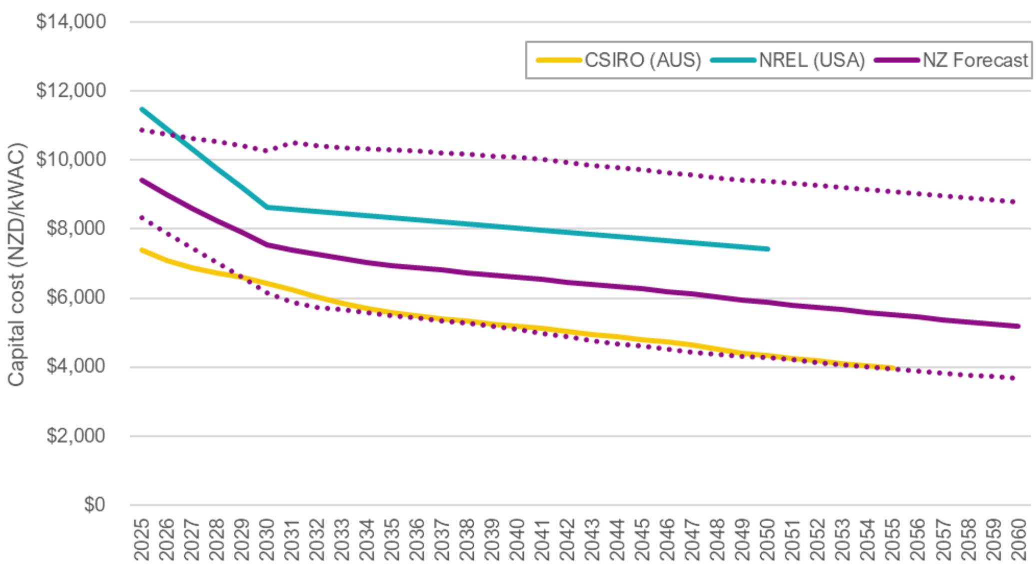

Figure 6-5 - Projected capital costs for concentrated solar power

6.2.4 Operating and Maintenance costs

We have used the simple average of CSIRO and NREL operating and maintenance costs. CSIRO indicates a variable O&M component of zero. NREL indicates that roughly 25% of O&M costs are variable. We have adopted CSIRO's approach assuming all O&M costs are fixed and converted the NREL variable O&M component to a fixed O&M component based on stated capacity factor.

6.3 Nuclear Small Modular Reactor (SMR)

6.3.1 Background

Small modular reactors (SMRs) are small nuclear power plants that can produce up to 300 MW of electricity. They are built in factories and then transported to their final location, which makes them theoretically quicker and cheaper to install than traditional reactors.

The likelihood of nuclear technology in general being accepted in New Zealand has not been considered. However, from a technical perspective, we consider SMR technology is the most likely nuclear technology that could be implemented in New Zealand, as the scale of an SMR makes it more likely to be able to be integrated into the New Zealand grid than other much larger scale plants.

6.3.2 Current cost estimate

The current cost estimate of SMRs is based on data from NREL and CSIRO. NREL has a significantly lower cost estimate for small nuclear technology of 20,400 $/kW, compared to the CSIRO estimate of 30,800 $/kW.[24] We have used the mid-point between these two estimates of 25,600 $/kW.

6.3.3 Cost trajectory

Both NREL and CSIRO assume significant learning curves, with the CSIRO learning curve being slightly greater than that assumed by NREL. We have applied the CSIRO learning curve, which results in a 2060 cost of 15,800 $/kW.

6.3.4 Other technical information

No consideration has been made at this point as to the wider industry investment that may or may not be required to support nuclear technology in New Zealand.

6.4 Pumped Hydroelectric Storage

6.4.1 Background

Pumped hydroelectric storage plants are not a new technology, but similar to river-fed hydroelectric dams there is a lack of New Zealand projects to draw information from, meaning our cost estimate has been developed based on international data. The available information sources typically consider pumped hydroelectric storage with reservoirs of a maximum of 48 hours. It is not anticipated that storage of this duration would be useful in the New Zealand context, as daily storage can primarily be serviced by grid scale batteries, so the main perceived purpose for pumped hydro is to cover dry year risk. In order to adequately mitigate dry year risk, a storage duration in the order of months would be required.

[24] The CSIRO values are taken from their 2024 GenCost report. This report paid particular attention to Nuclear SMR costs following criticism of the 2023 GenCost nuclear values. Given this, we consider the CSIRO values to be highly reliable, to the extent that it is possible to be for developing a new technology sector in a country.

6.4.2 Cost estimate

To estimate the cost for pumped hydroelectric we have utilised data from the UK Government's "Electricity Generation Costs 2023" report [4], CSIRO [1], NREL, and IEA [10]. The costs presented by these reports (when converted to 2025 NZD) are 8,700 $/kW, 8,600 $/kW, 7,900 $/kW, and 9,500 $/kW respectively. Because these are based on shorter duration storage, we have taken the average cost and applied an additional 10% cost to account for the additional civil works to establish larger reservoirs, noting that site selection is a critical factor. Based on this, we estimate a cost of 9,400 $/kW.

As a comparison, a selection of estimated costs for a number of potential and in-flight projects have been analysed and are summarised in Table 6-1.

Table 6-1 - Pumped Hydroelectric storage Project Costs

Project	Capacity (MW)	Storage Duration (Days)	Cost (NZD/kW)
Snowy 2.0 (NSW)	2,200	6.6	6,300
Lake Onslow (NZ)	1,000	208.3	16,800
Burdekin (QLD)	5,000	1	6,300
Borumba (QLD)	2,000	1	10,200
Kidston (QLD)	250	0.3	4,000
Oven Mountain (NSW)	900	0.3	2,500

As can be seen from table 6-1 there is a wide range of costs across pumped hydro storage projects because of project specific factors. The average cost per kW for the projects referenced is: 7,700 $/kW. If an average is taken of the above projects excluding Oven Mountain, which has particularly favourable conditions in its favour, then the average cost per kW is 8,700 $/kW. It is noted that of the projects assessed only Snowy 2.0 and Lake Onslow have a storage duration of more than 1 day.

6.4.3 Cost trajectory

The learning rate from CSIRO has been applied to this and reflects relaxing of inflationary pressures in the short term followed by moderate cost increases as a result of predicted installation cost increases, resulting in a 2060 cost of 9,400 $/kW. This is shown in Figure 6-6.

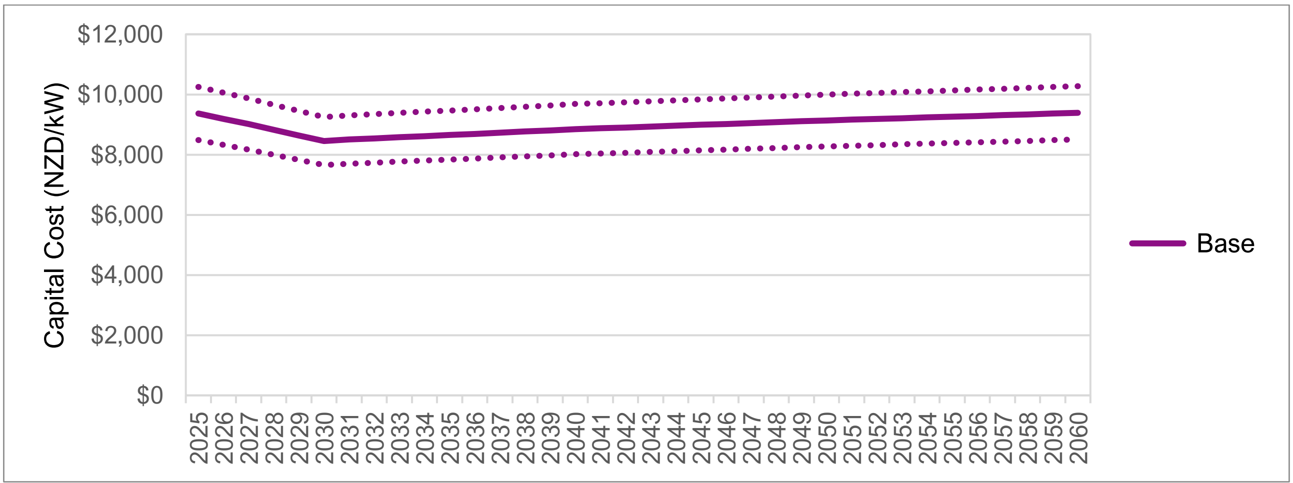

Figure 6-6 - Pumped Hydro Cost Trajectory

6.4.4 Specific project costs

No specific projects have been considered, as at the time of writing there was no specific project data available. However, as noted, any real project costs will be heavily site dependent.

7 Speculative Technologies

Speculative technologies are immature and have less sources to draw from for information. As such, the costs presented in this section are less well supported but still provide information for consideration into potential future development pathways.

7.1 Deep Geothermal

Deep geothermal is defined by NREL as resource at a depth of between 3-7 km. We have only sourced costing information from NREL for this technology and the current estimated cost is 15,900 $/kW. This forecast provisions for a moderate learning curve with costs reducing to 10,500 $/kW by 2060.

7.2 Hydrogen Fuel Cell

There are a number of potential ways in which hydrogen could be used for either generation or storage. For the purpose of this report only hydrogen fuel cells have been considered. However, it is noted that hydrogen blends may be viable with a number of the thermal technologies considered. For hydrogen fuel cells, we have sourced information from CSIRO, which provides a current estimated cost of 8,500 $/kW, reducing to 6,400 $/kW by 2060.

7.3 Nuclear Fusion

Nuclear fusion is a potential future technology which is attracting significant investment at present. However, no reliable cost forecasts are available at present. No attempt has been made in this report to estimate the future cost of nuclear fusion generation

7.4 Ocean Technologies

Limited data is available for wave and tidal/ocean current generation technologies. However, cost estimates have been provided in the CSIRO, which, converted, provide respective current cost estimates of 15,400 $/kW, and 12,400 $/kW. The corresponding future cost estimates for 2060 are 12,200 $/kW and 8,900 $/kW for wave and tidal/ocean current respectively.

A

Appendix A – Specific Project Assumptions and Methodology

This appendix outlines the process by which we used publicly available information on specific potential wind and solar projects to estimate values to include in our supply stack.

Data sources and verification

We used Concept Consulting's database of prospective generation projects as a starting point for project information. This database is based on public information and is routinely updated. We extracted the following data:

- Project name
- Technology type
- Capacity in MW_{AC} (where public information is provided only in MW_{DC}, this is converted assuming an DC:AC oversizing of 18%)
- Connection information (including transmission vs. distribution connection, connection voltage, new substation requirements, and approximate distance from connection)
- Accessibility rating based on a high-level qualitative assessment of the site's topography and location (for wind projects only)
- Cost information (where available).

We excluded projects that were:

- Small (less than 10MW)
- Already commissioned, under construction, or committed (i.e. having reached final investment decision).

Accessibility cost adjustments for wind projects

Concept Consulting's database includes a qualitative assessment of the accessibility of the site, based on a desktop review of topography, road infrastructure, and distance to ports. Projects were categorised as follows:

- 1 – more accessible sites (i.e. "plains")
- 2 – somewhat accessible sites
- 3 – less accessible sites (i.e. "hilltop")

Transpower conducted a GIS-based assessment of the steepness of onshore wind sites, which we compared to our qualitative assessment of these sites. Where there was a material difference in our assessments, we conducted a more detailed qualitative assessment based on all available information.

Connection cost adjustments for wind projects

Concept Consulting's database includes the following connection information:

- Connection type (grid-connected or embedded).
- Connection voltage (220 kV, 110 kV, 66kV, or 33kV).
- Whether or not a new substation is required.
- Distance to point of connection (i.e. line length, in km).

Where the database did not include relevant connection information for a specific project (i.e. where this is not publicly available), we assumed the following:

- Unclear connection type – we assumed projects above 100MW are grid connected and smaller projects are embedded.
- Unclear connection voltage – we assumed projects above 100MW connect at 220 kV, projects 70MW and above connect at 110 kV, and any embedded projects connect at the highest sub-transmission voltage available on the relevant distributor's network. There were no grid-connected projects with a capacity below 70MW.

- Unclear substation requirements – we assumed fixed connection costs (i.e. costs not related to distance from grid) are halfway between the costs of building a new substation and the cost of connecting to an existing substation.
- Unclear line length – where site location and connection location were both known, we calculated the direct distance 'as the crow flies' between these points, otherwise we assumed a default line length of 10km. Note that where a project site is adjacent to the point of connection, we still assumed a nominal 2km line length due to the spread out nature of many wind sites.

We calculated connection costs (in $M) based on the following formula:

$$[line\ cost\ per\ km] \times [line\ length] + [fixed\ costs]$$

Fixed cost and line cost estimates were based on Transpower estimates, and varied based on connection voltage, as shown in the table below:

Connection voltage	**33kV**	**66kV**	**110 kV**	**220 kV**
Line cost ($M) per km	0.5	1	1	2
Fixed cost ($M) – new substation required	5	10	20	40
Fixed cost ($M) – connecting to existing substation	1.5	2.5	3.5	5
Fixed cost ($M) – substation requirements unclear	3.25	6.25	11.75	22.5

Some adjustments to this approach were made in specific circumstances, in particular:

- Where a project has a capacity of 300 MW or above, we have assumed it requires double circuits to ensure n-1 reliability. As such, we adjust our calculations as follows:
  - 50% higher per km line costs (i.e. 3 $/kW, since all projects of this size connect at 220 kV)
  - an additional $10M in fixed costs.
- Where a project is an expansion of an existing project (i.e. a "stage 2), in some cases we assumed that no new substation is required and that the line length is a nominal 2km (i.e. the expansion is adjacent to the previous stage of the project). We did not take this approach where:
  - the expansion would cause the project as a whole to reach 300 MW or above and therefore require n-1 reliability.
  - the expansion is materially larger than the previous stage of the project, and therefore likely requires a larger connection.

B

Appendix B – Stack Data Output