Generation investment survey 2022

Prepared for Electricity Authority

July 2022

Key points

1. **Forward prices and estimated costs**
   - While forward contract prices have a declining profile, they remain well above the estimated cost of new supply at least until 2025. A similar outlook applies in Australia, but contract prices are converging toward the cost of new supply at a faster rate in most Australian regions.
2. **Investment requirements and pipeline of potential developments**
   - New generation is needed to offset demand growth and to displace thermal generation that has become increasingly uneconomic due to steeply rising carbon and fuel costs.
   - Compared to 2021, we estimate a total new generation requirement of 6,000 GWh/year is needed by 2025.
   - Generation development has accelerated. Based on already committed projects, new investment is now ~2.5 times the average rate achieved last decade. But projects built or committed since 2021 will only meet around 3,000 GWh/yr (~50%) of the projected additional generation need by 2025.
   - Other potential projects are at various stages of maturity. Based on survey data and other sources, we estimate there is around 8,000 GWh/yr of potential generation that could be on stream by 2025. Most of the projects are solar farms, with wind farms accounting for most of the remaining potential generation. Much of the solar pipeline is being pursued by large overseas developers.
3. **Factors hindering faster development**
   - Resource Management Act requirements have a significant effect on development pace, especially for wind projects.
   - Overseas investment consenting arrangements were reported as a significant concern by many large overseas solar developers.
   - Securing offtake agreements was a critical issue for some developers, while others expressed some willingness to take on a degree of offtake risk (especially during a build phase).
   - Connection study requirements were seen by some developers as unduly slow/complex, and many raised a question about whether physical grid capacity would keep up with generation expansion further into the future.
   - Regulatory predictability was seen as important for many developers, particularly the need to avoid measures that could increase longer term uncertainty – most overseas parties saw New Zealand's environment as relatively positive for development.
   - Demand uncertainty was a factor that developers have in mind, but many were focusing their efforts on North Island projects to mitigate exposure to any Tiwai smelter closure.
   - Cost pressures were cited as a frequent concern. Many developers felt that costs were elevated at present due to tight supply chains and labour markets. Developers spoke of the need to carefully weigh the benefits of delaying investment (to avoid locking in a high build cost) versus the benefits of developing now (to capture some higher revenues in the front end of a project life).

How do forward contract prices compare with estimated cost of new supply?

We estimate the long run cost of new supply to be around 76 – 92 $/MWh (baseload terms at Otahuhu)

Key points

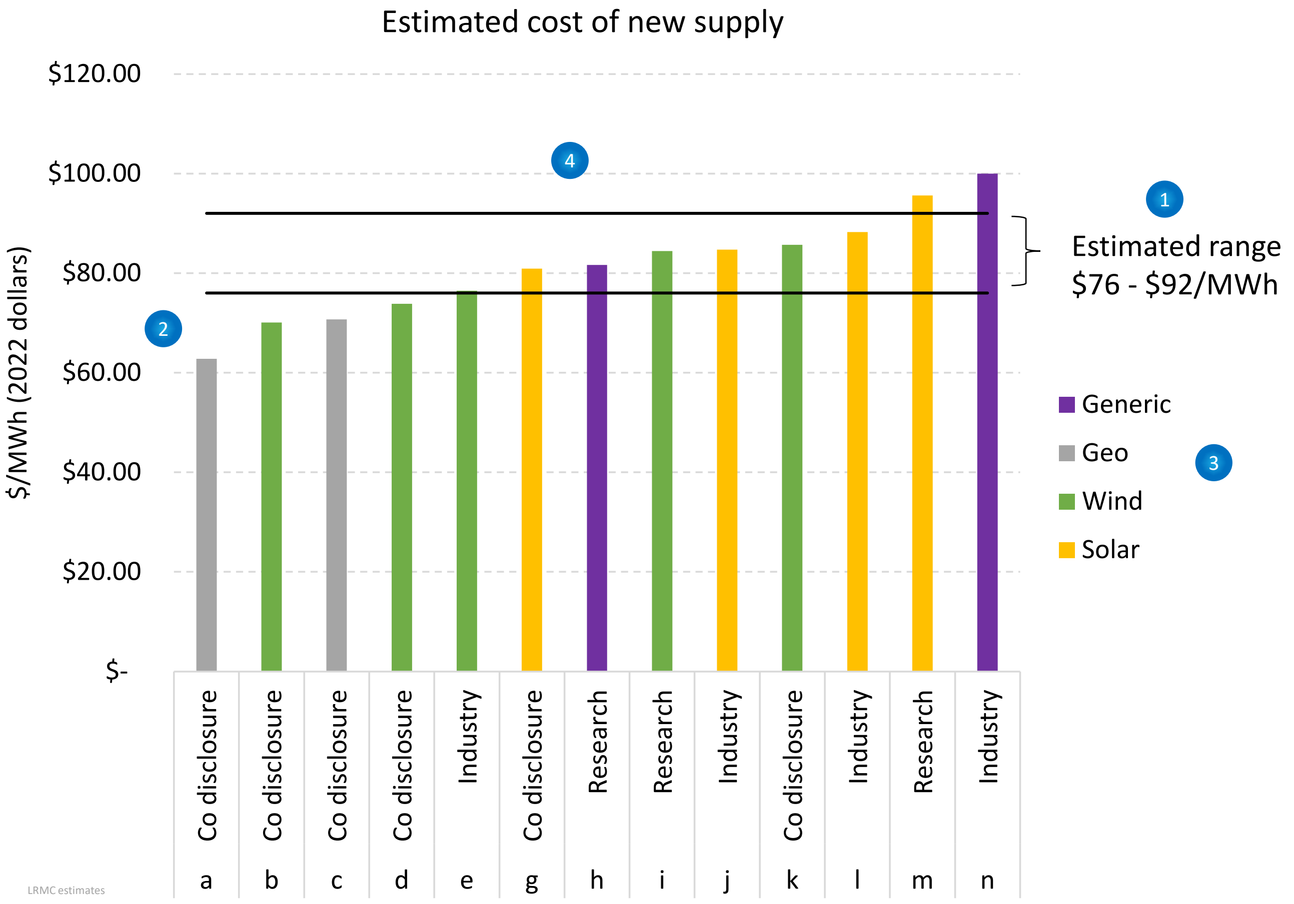
1. We estimate the long run cost of new supply to be around 80 $/MWh. However, there is heightened upside risk in the near term due to a range of global economic factors (see later slide). For this reason, we apply an uncertainty range of -5% to +15% equating to 76-92 $/MWh (2022 dollars).

2. Costs for some existing projects are lower than the estimated range for new supply. These projects are expected to be infra-marginal and therefore not relevant for determining market clearing prices.

3. In broad terms, geothermal projects are expected to be the most competitive, but are limited by resource availability. Wind projects are the next most competitive energy source, but solar costs have been falling and the best solar projects are becoming competitive with wind.

4. Wind and solar are expected to be the major source of new supply but both are intermittent in nature. A GWAP/TWAP adjustment factor has been applied to each project to convert it to firm terms (see notes under chart for more detail). Prices are also adjusted by location factors where relevant.

5. We think most industry estimates lie in a similar range to our view – though some are higher (e.g. a Forsyth Barr report in July 2022 included an estimate of 107 $/MWh).



Notes
- All estimates have been converted to a base load equivalent cost at Otahuhu in 2022 dollars
- Co disclosure = the estimate uses information drawn from company disclosures to media or stock exchange
- Industry = the estimate uses information drawn from discussions with industry experts.
- Research = the estimate uses information drawn from external research reports
- GWAP = Generation weighted average price, TWAP = time weighted average price. The GWAP/TWAP ratio indicates the proportion of the baseload i.e. TWAP) price captured by a generation type. It has been estimated from historical data and forecast projections.
- Survey interviews did not seek information on the estimated cost of new supply and have not been used as a source for this analysis.

Contract prices for 2022-2025 are well above the estimated cost of new supply

Key points

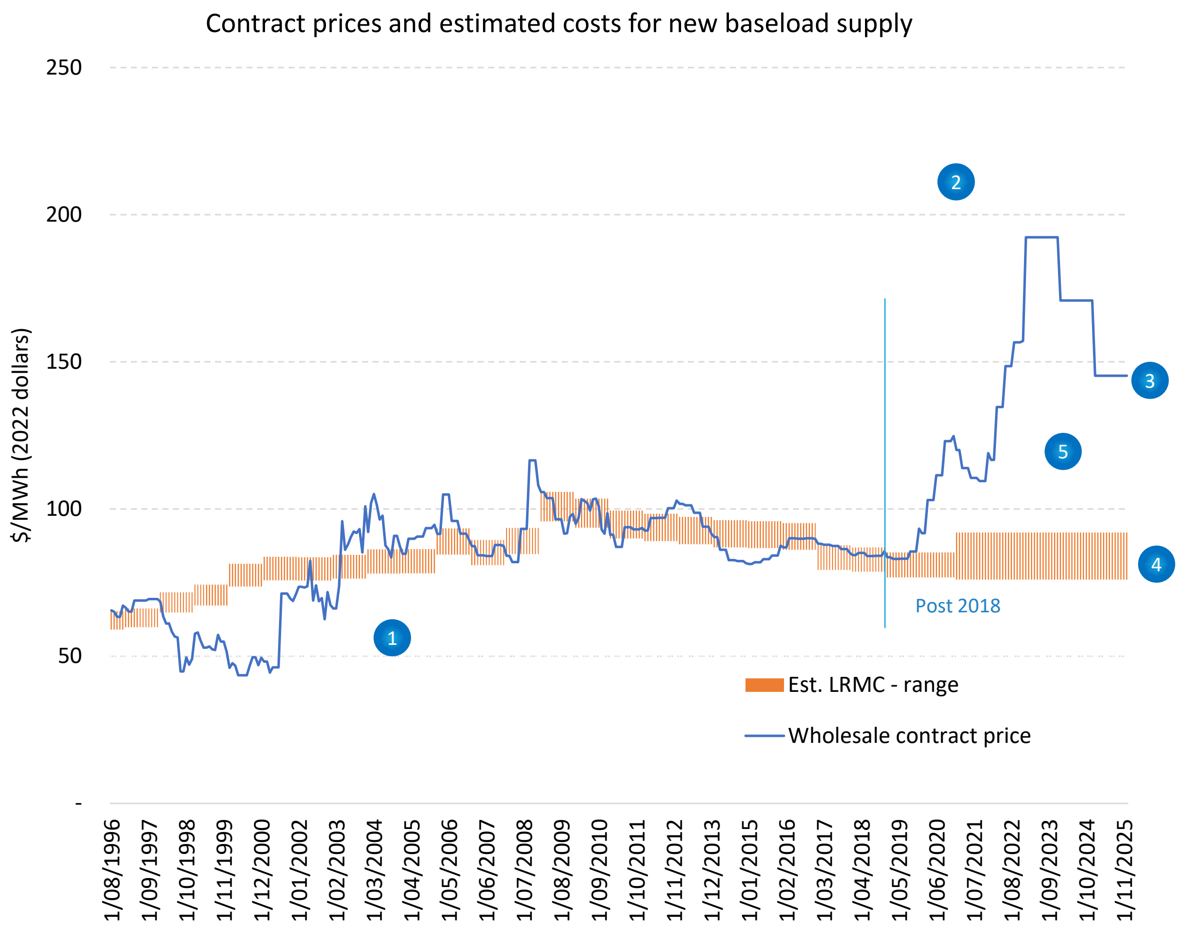
1. Until 2018 contract prices tracked relatively closely to the estimated cost of new baseload supply (albeit with fluctuations at times).

2. Since 2019, contract prices have been significantly above the estimated cost of new supply.

3. While forward contract prices for 2023- 2025 are trending downwards, they are still well above the estimated cost of new supply.

4. The new supply cost range is an *estimate.* The range on the chart has widened post-2020 to reflect:
    - Increased uncertainty about costs of plant (wind turbines and solar) in the next few years due to supply chain disruption
    - Increased uncertainty about construction costs in the next few years due to tight markets for contractors and specialized equipment such as high lift cranes
    - Increased uncertainty about the cost of firming intermittent renewable generation.

5. Notwithstanding the uncertainty about the estimates, it is clear that contract prices exceed longer-run costs of new supply.



LRMC estimates.xlsx

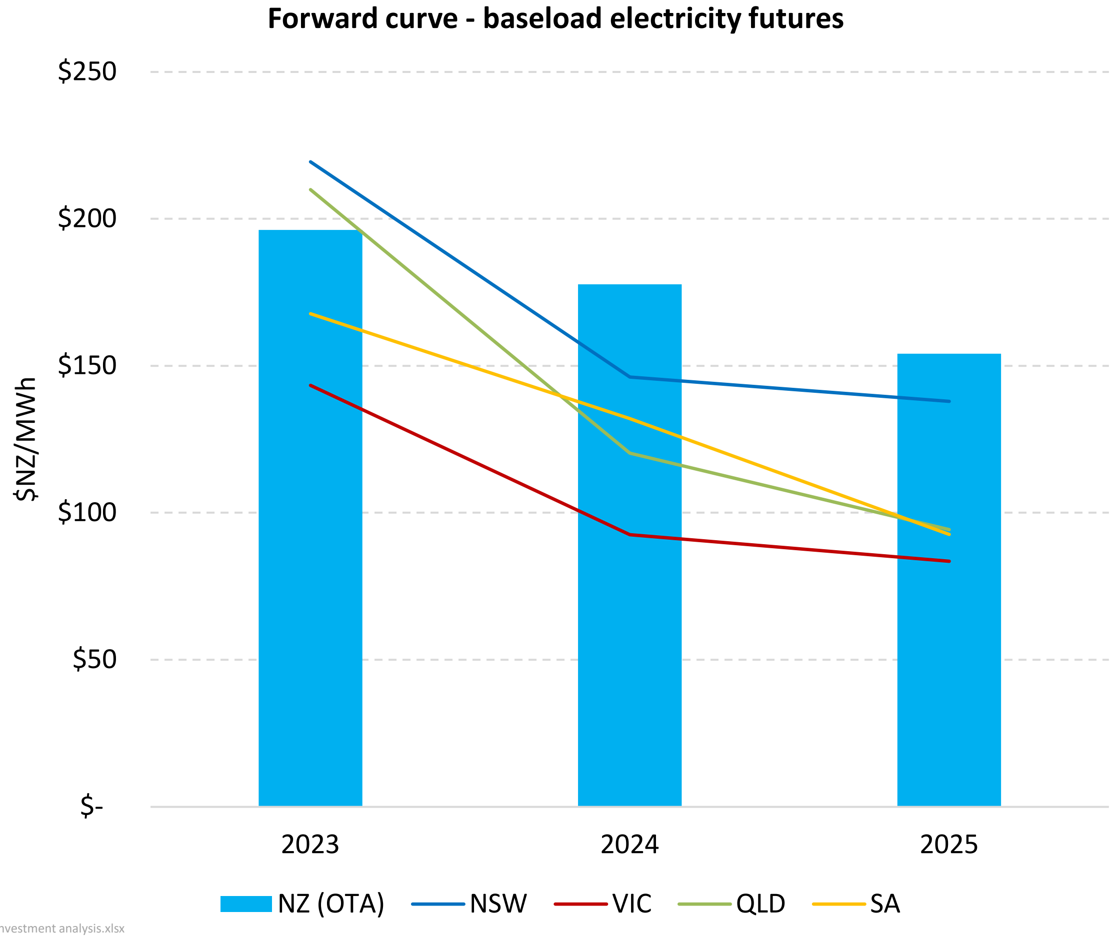
Notes

- Pre-2019 data is from Electricity Price Review Technical Paper – see www.mbie.govt.nz/dmsdocument/4334-electricity-price-review-first-report-technical-paper
- Contract prices post 2019 are from electricity futures contracts quoted on ASX. They are deflated using CPI, with assumed inflation of 2% for future years.
- Estimated costs for new baseload supply post-2019 are derived by Concept from multiple sources. See earlier slide.

Contract prices for 2023-2025 are also elevated in the Australian electricity market – but decline faster in out years for most regions compared to NZ

Key points

1. While the Australian National Electricity Market (NEM) is subject to a range of influences that are different to NZ, it nonetheless provides a point of comparison.
2. Baseload contract prices in the NEM show a similar forward profile to NZ, with near term elevation and declining trend over time.
3. Contract prices in the NEM are trending toward ~100 NZ$/MWh by 2025 for most regions.
4. The rate of decline in NZ is less steep than in the NEM, except for the New South Wales region.



investment analysis.xlsx

Notes
- Prices were downloaded in mid July 2022

What new renewable generation is committed, and what further potential supply is in the pipeline?

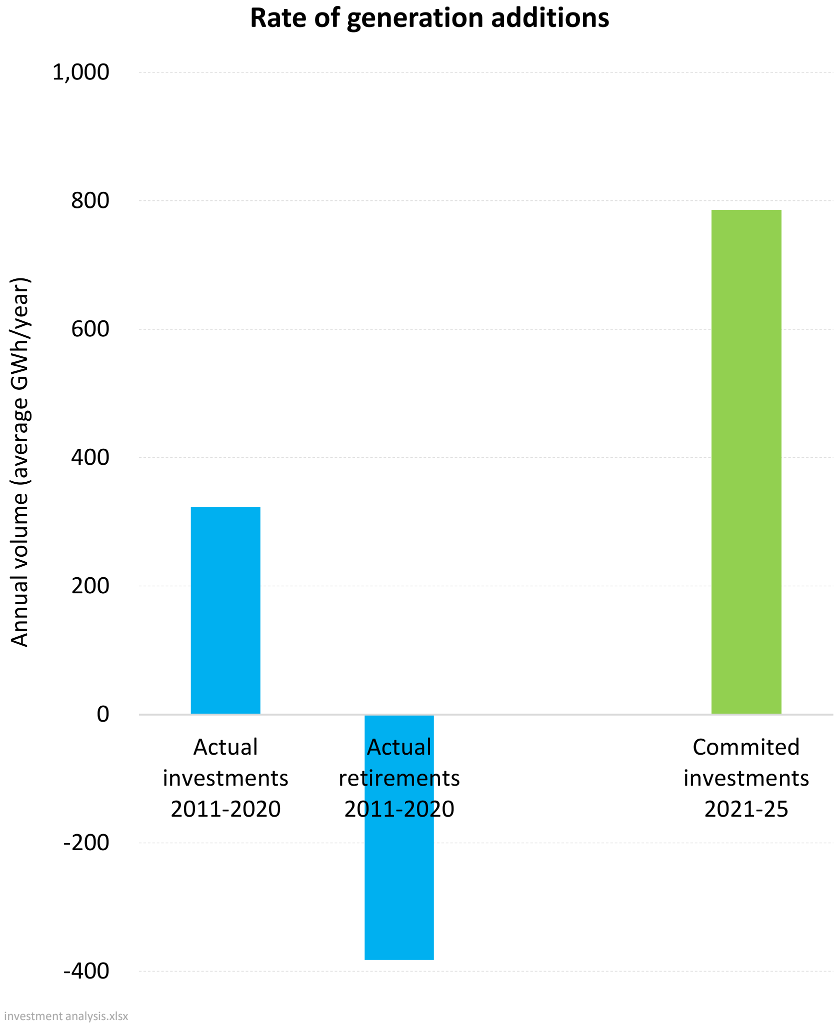
Generation development pace has lifted significantly compared to the previous decade, based on projects that have been built/committed this decade

Key points

1. In the decade to 2020, *gross* new generation additions averaged 320 GWh per year.

2. All of those additions were offset by retirement of thermal plant (e.g. Otahuhu B and Southdown) - meaning that *net* generation additions were nil over the period.

3. Based on recently developed/committed projects, gross new generation additions will average around 780 GWh per year between 2021 and 2025 – around 2.5x the historical rate of development.



Notes

- Assumed capacity factors are wind (40%), geothermal (98%), peakers (25%), hydro (50%) and baseload thermal/cogen (90%)
- Committed investments for 2021-2025 includes Waipipi and Turitea North

We have extensively engaged with the industry to develop a comprehensive picture of the pipeline of further potential projects

We conducted interviews with the following parties:

Independent generation developers	Vertically integrated parties	Network companies	Other
•Copenhagen Offshore Partners •Far North Solar Farms •Helios •HES Aotearoa •Island Green Power •Lodestone •Manawa Energy •NZ Windfarms •Parkwind •Pioneer Energy/ Southern Generation •Solar Bay	•Contact •Genesis •Mercury •Meridian •Nova	•Alpine Energy •Aurora •Orion •Top Energy (also a generation developer) •Transpower •Vector •Wellington Electricity	•Anton Trixl (energy sector lawyer at Anderson Lloyd) •David Thomas (managed the Renewable Energy Project Caucus process) •Ecotricity (retailer) •Fonterra (electricity offtaker) •Hiringa (electricity customer, generation developer and hydrogen producer and distributor)

We also obtained data from other sources on the projects being developed by the following:

Not interviewed (relied on data from public domain, Transpower or other sources)	
•ANSA Holdings Ltd •Aurecon •CIAL •Eastland Group •Elemental Group Ltd •Energy 3 •Energy Estate •Energy Farms •ESCO Pacific •Grupo Grandsolar •Harmony Energy •Hydro Developments Ltd	•Infratech •Kea Energy •Kiwi Solar Farms •Lightyears Solar •NZ Clean Energy •NZRC •Oji Fibre Solutions •Ranui Generation •SkySolar Ltd •Tainui Holdings Limited •Ventus

Key points

1. Together with Authority staff, we engaged extensively with developers and other parties, via approximately 30 interviews + email follow-ups.

2. Concept would like to record its appreciation for parties' willingness to be interviewed and provide information for this work.

3. Remaining data is derived from public sources (media reports, broker reports, investor presentations, etc.) where we have been unable to engage with respective developers or the expected scale of a project(s) was not large enough to warrant a specific interview.

Notes

In processing investment pipeline data from these interviews, we:

- Focused on generation output (GWh/yr) rather than capacity (MW). Where only capacity data (MW) was available, we assumed capacity factors to determine generation output data (see Appendix)
- Focused on investments that could realistically be completed by 2025. This is the period covered by the ASX futures product. We also considered investments that are likely to be commissioned in 2026-2030, but with less focus as these are more uncertain and further as yet unknown projects will likely emerge that could be commissioned in this period.
- Included efficiency upgrades as new investments for pipeline purposes.
- Excluded investments in storage or non-renewable generation.

Depending on their status, potential developments are categorised into one of three groups:

- Committed projects (i.e. when the unconditional final investment decision has been made. This category should already be baked into the forward curve)
- Actively pursued projects (i.e. when a site has been identified and the developer has started actively considering at least one of: finance, connection, consents, etc). These are the most relevant projects for the purposes of this investigation, especially those that may be completed by 2025, as they represent projects that have a higher probability of proceeding. Note that the 'actively pursued' category excludes consented projects that appear unlikely to proceed based on current information.
- Other projects (i.e. projects that are either in very early stages of development or have been put on hold. These projects are unlikely to be built in the next few years, so they are of less relevance to the investment picture in the period 2022-2025. Some of the potential generation in this category may count as "bragga-watts – i.e. may be unlikely to be built at all).

There is more potential generation in the development pipeline than is apparent from public sources

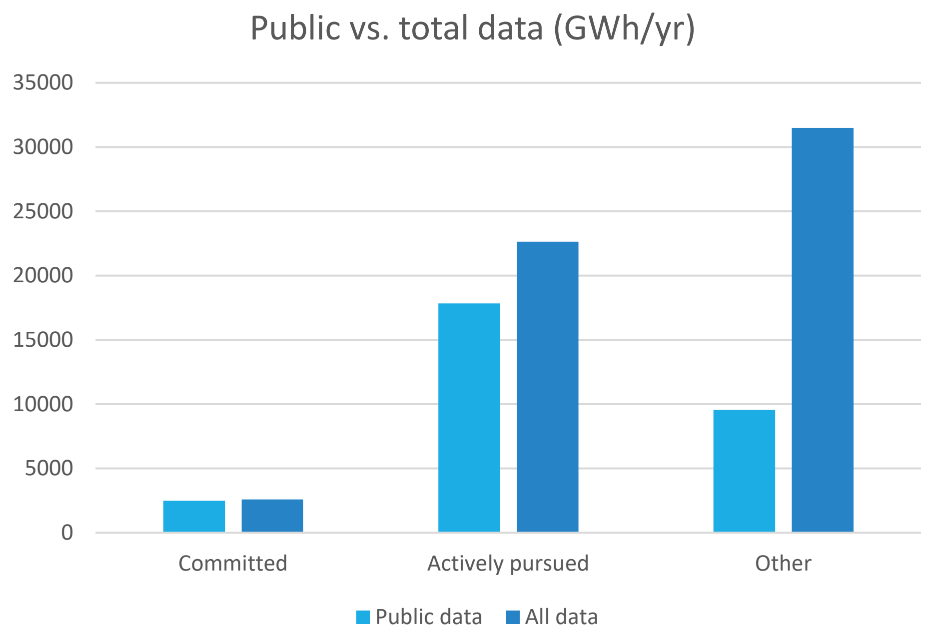
Development pipeline (GWh/yr)

	2023	2024	2025	2026+	**Total**
Committed	1,822	762	6	19	**2,609**
Actively pursued	3,072	2,638	2,402	14,520	**22,633**
Other	526	451	165	30,351	**31,492**
Total	**5,420**	**3,851**	**2,573**	**44,890**	**56,734**

Key points

1. The development pipeline is large. It contains 'active projects' (see definition on previous slide) with potential to produce ~23,000 GWh/yr by 2030. In addition, there are 'other projects' with potential to generate around ~31,000 GWh/yr by 2030 (recognizing that some potential projects will not proceed to development).

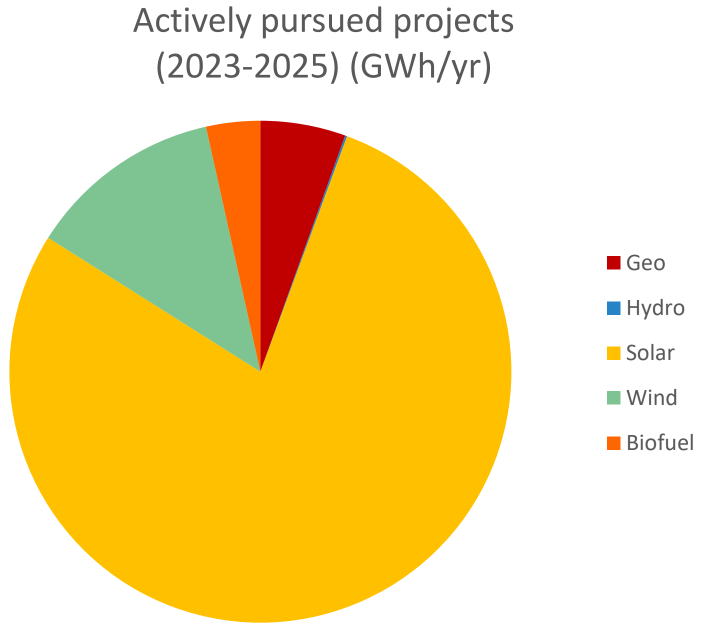
2. Much of the development pipeline is not in the public domain. Some developers fly below the radar, and some developers with a public profile are working on projects not yet in the public domain. 53% of GWh/yr (on aggregate across committed, actively pursued and other projects) came from publicly disclosed projects, while 22% came from interviews and other non-public sources and a further 25% from Transpower's connection enquiry data.



Notes

- Transpower's connection enquiry data has almost 70,000 GWh/yr of project enquiries. However, many of these projects were not added to our development pipeline because they are:
  - In the public domain already (therefore already included in our dataset).
  - From developers we interviewed (and information from these interviews is likely to be more accurate than connection enquiry data).
  - From lines companies without specifying the actual developer (and there is a risk that these projects are already included in our dataset).
  - Categorised by Transpower as "unlikely" to proceed (i.e. <5% likelihood)
- We categorise the status of the remaining projects from Transpower's data as follows:
  - Projects classified by Transpower as "in delivery" are treated as "committed" projects for our purposes.
  - Projects classified by Transpower as in the "investigation" or "concept assessment" stages are treated as "actively pursued" projects for our purposes.
  - Projects classified by Transpower as in the "prospect" or initial inquiry" stages are treated as "other" projects for our purposes.
- We assumed possible commencement dates for these projects from Transpower's data as follows:
  - "Likely" (~75% likelihood of proceeding) or "Possible" (~50% likelihood of proceeding) solar projects are assumed to have a possible completion date prior to 2025.
  - "Possible" (~50% likelihood of proceeding) biofuel projects are assumed to have a possible completion date of 2025.
  - "Uncertain" (~25% likelihood of proceeding) projects (of any generation type) are assumed to have a possible completion date after 2025.

Most of the investment pipeline will only be available in the second half of the decade. Most of the generation development available by 2025 is solar



Key points

1. We estimate that around 8,100 GWh/yr of actively pursued generation could technically be completed by 2025.

2. Much of the development pipeline is still some years away. A larger proportion of actively pursued generation (around 14,500 GWh/yr) could only be feasibly completed in the second half of the decade.

3. Much of the development pipeline is uncertain. There is over 31,000 GWh/yr of “other” potential generation developments in the development pipeline, although these projects are all either on hold or still speculative. Very few of these projects would be able to be completed before 2025 even if they were actively pursued.

4. In the near term, solar development is likely to be particularly relevant. 78% of actively pursued projects (by GWh/yr volume) that could be completed by 2025 are solar projects, most of which are in the hands of international developers.

How much additional generation is needed, and how does this compare to the pipeline?

We project an additional investment requirement of ~3,000 GWh/yr by 2025 – ASX forward prices indicate this will not be fully achieved

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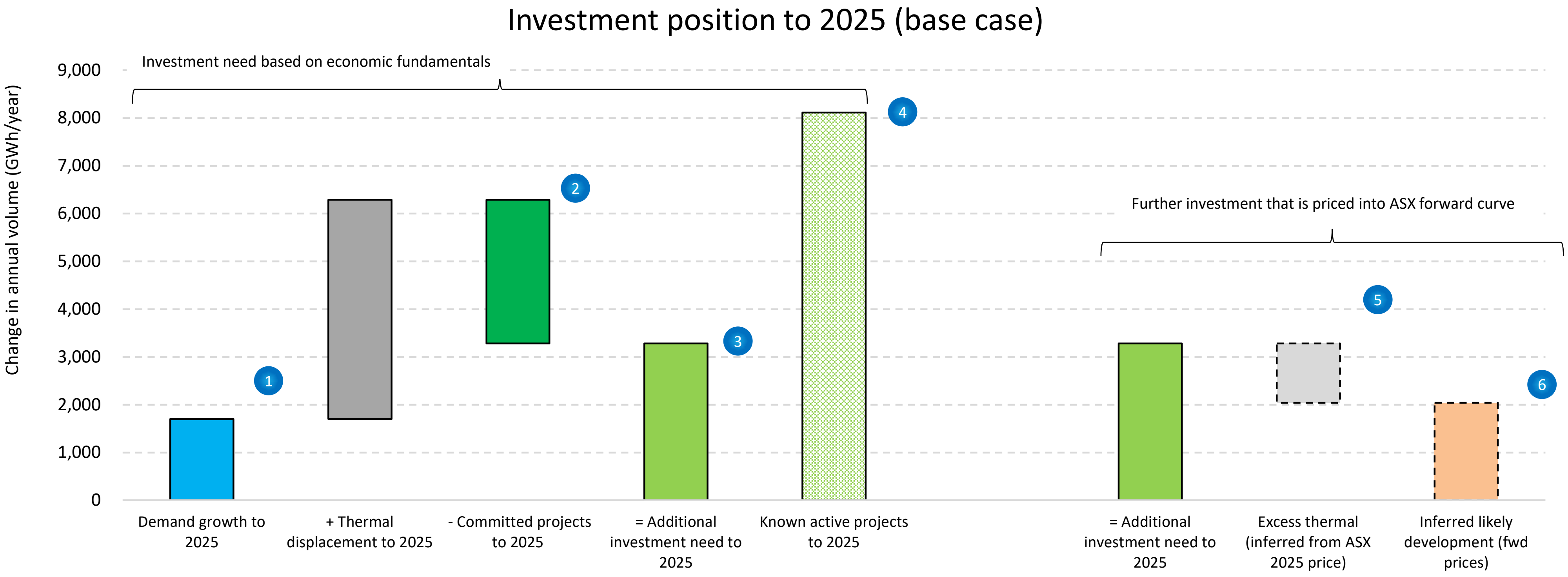


investment analysis.xlsx

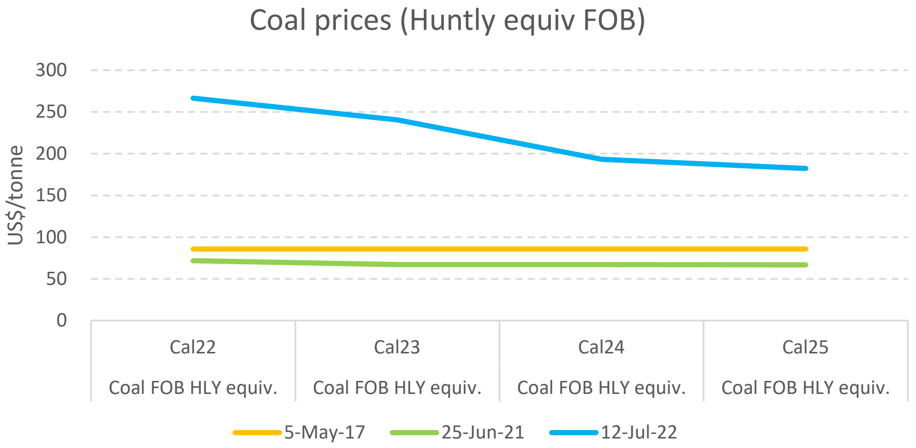
Key points

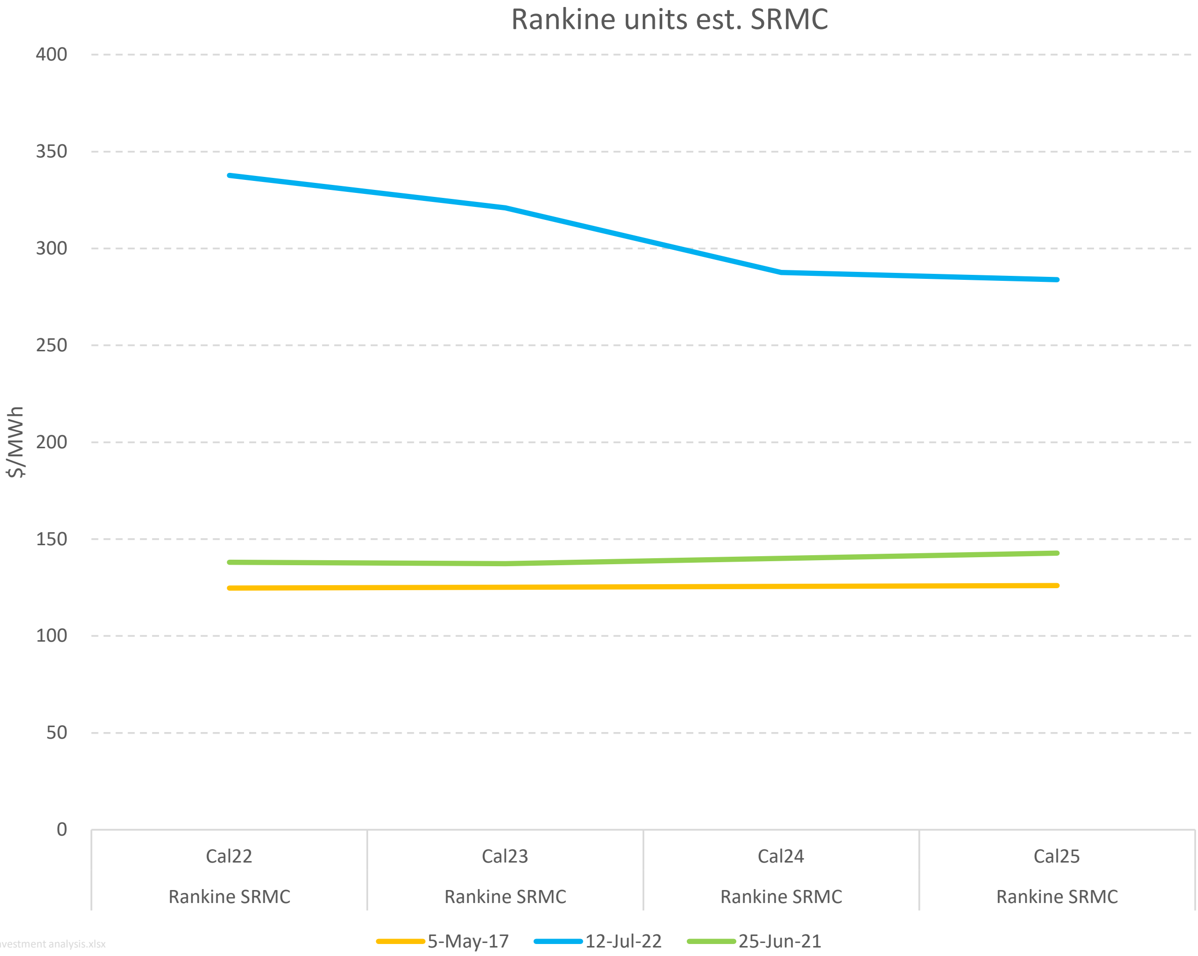
1. Demand growth (~1% p.a.) is a key factor behind requirement for new generation, but bigger driver is economic displacement of thermal generation. Higher fuel and carbon costs have significantly expanded scope for renewable generation to displace thermal (see next slides).
2. Committed renewable projects provide sufficient generation to more than offset projected demand growth, but less than required to economically displace thermal. This means any shortfall in new investment will likely result in elevated wholesale prices rather than outages (assuming thermal remains available). Note that thermal figures are mean generation volumes. Thermal plant would still be required to provide flexibility when renewable production is lower than mean, and for capacity purposes.
3. There is a need for around 3,000 GWh/yr of new supply to bring the market into balance by 2025 under base case assumptions.
4. There is around 8,000 GWh/yr of new supply available from known active projects that could be available by 2025. A conversion rate of ~40% (from active to developed) would be required to fill the projected gap.
5. ASX prices for 2025 imply higher-cost thermal will be operating for a greater proportion of time than would be the case if the market was in equilibrium – around 1,200 GWh/yr more than is optimal
6. Put another way, ASX prices imply that a further ~2,100 GWh/yr of new supply will be developed by 2025 (a conversion rate of ~25% cf. currently identified active projects).

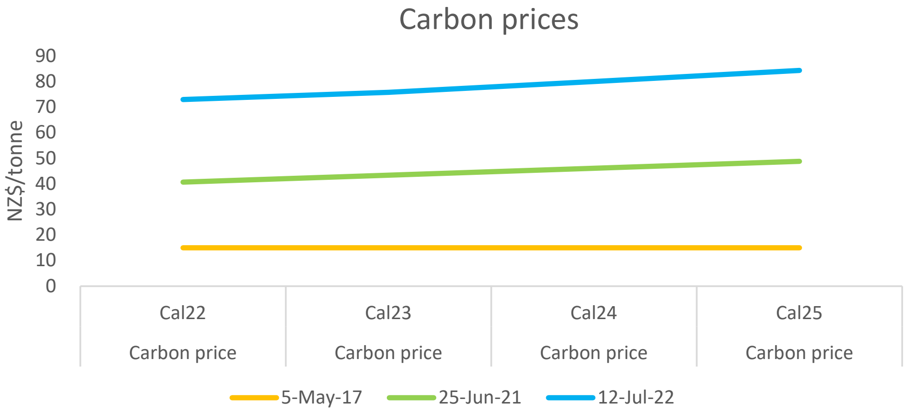
Notes

- Based on analysis of energy requirements and excluding firm capacity issues. It was not practical to undertake an equivalent analysis based on capacity requirements within the time and resource available for this study. Having said that energy requirements are expected to remain as the main investment driver for the period to 2025.
- Demand growth projection is mid-point of *Measured Action* and *Mobilise to Decarbonise* cases in Whakamana te Mauri Hiko report by Transpower. Both assume Tiwai smelter continues operation post-2024.
- Thermal displacement is volume of fossil fuel generation (ex cogen) that is estimated to be economic to displace based on forecast carbon and fuel prices in 2025 and projected cost of new renewable supply (assumed to be 84 $/MWh on a firmed basis).
- Known 'active' projects to 2025 are those for which work is underway on consents, offtake and/or connection arrangements.
- Excess thermal (inferred from ASX 2025 price) is back-calculated by comparing actual forward price with expected price if the market was balanced (i.e. contract prices = cost of new supply including firming). The resulting figure is sensitive to input assumptions.
- Inferred likely development is volume of further new development that is implied by ASX forward price.

The lift in fuel and carbon prices is making it economic to displace a greater volume of thermal generation with renewables



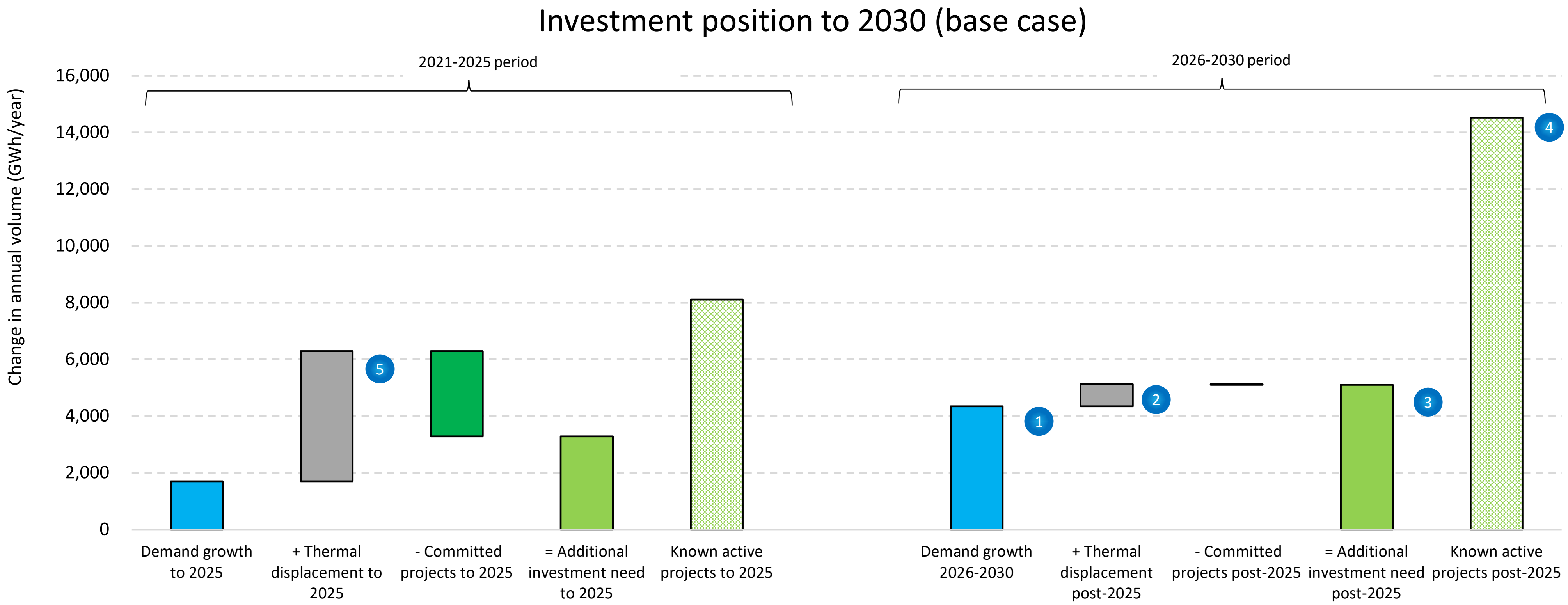




investment analysis.xlsx

Notes
- Based on forward prices for Newcastle coal (adjusted to HBA Indonesia equivalent) and NZU (carbon) prices.
- Rankine SRMC assumes coal is the marginal fuel source.

Our analysis indicates the investment requirement is more challenging in 2021-25 than 2026-30, largely because thermal displacement is ‘front-loaded’



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Key points

1. Demand growth in the second part of the decade is expected to accelerate as decarbonisation gathers momentum.
2. Post-2025 there is less scope to further displace thermal generation, simply because it is economic to do so before 2025 based on projected fuel and carbon prices at that date.
3. The projected volume of total new generation required in the period 2026-2030 is ~5,100 GWh/yr, slightly lower than the total volume for 2021-2025 (~6,000 GWh/yr being a mix of committed and further requirements).
4. There is a large volume of projects actively being pursued for development beyond 2025 – as a result the conversion ratio required to meet the projected investment need in the latter part of the decade is around 35%.
5. The significant volume of thermal displacement that is economic by 2025 is a key reason that the investment requirement is front loaded.

Notes

- Demand growth is mid-point of *Measured Action* and *Mobilise to Decarbonise* cases in Whakamana te Mauri Hiko report by Transpower. Both assume Tiwai smelter continues operation post-2024.
- Thermal displacement is volume of fossil fuel generation that is economic to displace based on forecast carbon and fuel prices in 2025 and projected cost of new renewable supply.
- Known ‘active’ projects to 2030 are those for which work is underway on consents, offtake and/or connection arrangements, or other similar factors.
- Based on analysis of energy requirements rather than capacity requirements.

Projected additional investment need is sensitive to certain factors – especially the future operation of the Tiwai smelter

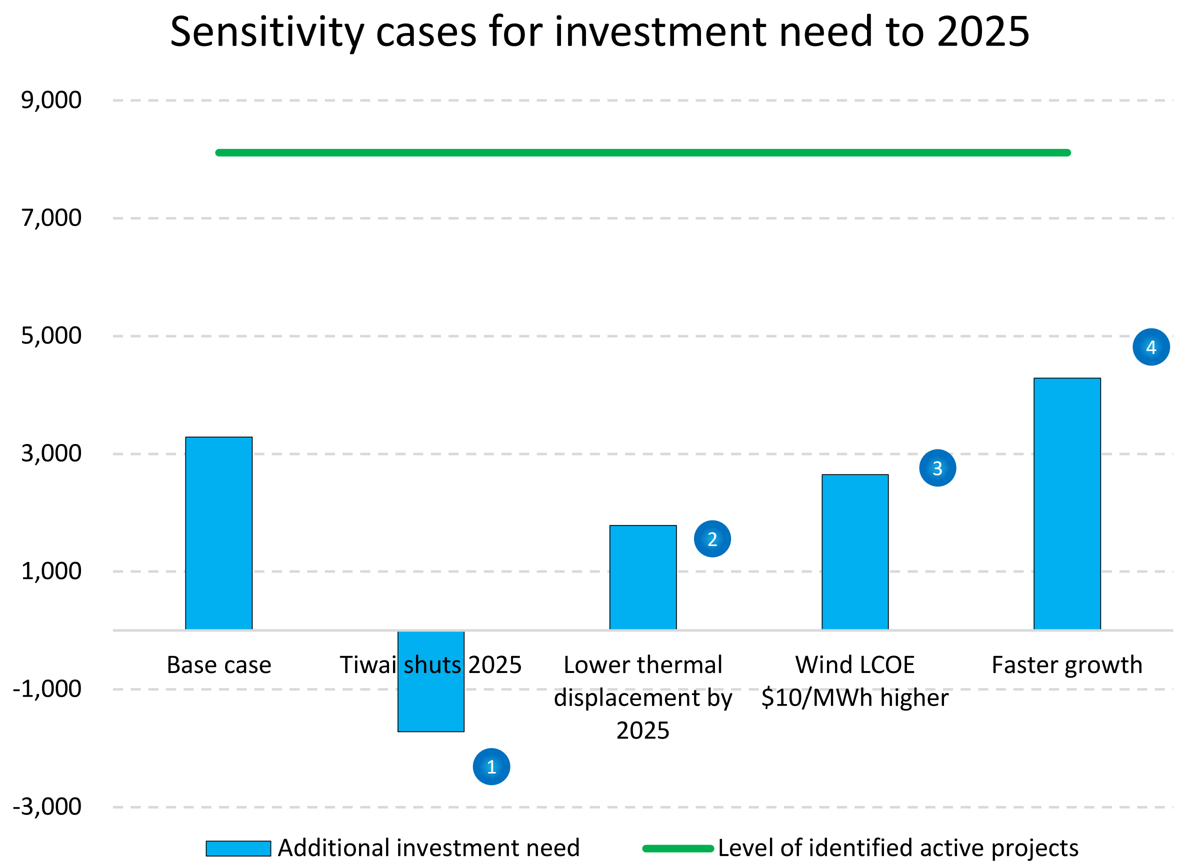
Key points

1. Additional investment requirement is very sensitive to Tiwai smelter demand. The base case assumes Tiwai smelter continues to operate post 2024. If closure were to occur, there would be no need for further investment prior to 2025.

2. If thermal costs in 2025 are lower, that makes thermal generation more economic and reduces the projected need for new renewables. The sensitivity case shows the effect if Rankine SRMC on coal is around 140 $/MWh rather than 280 $/MWh for 2025.

3. Higher costs for new renewables would make thermal more economic in relative terms. The sensitivity case shows the effect if wind costs (including firming) are ~94 rather than ~84 $/MWh.

4. Faster demand growth would lift required investment. The sensitivity case shows the effect if demand is 1,000 GWh/yr higher than the base case by 2025.



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Notes

- Tiwai shuts case assumes smelter closure from January 2025.
- Lower thermal displacement case shows the broad effect if thermal/carbon prices in 2025 are at levels projected in mid-2021 (based on 2025 futures prices for coal and carbon in mid-2021). This reduces the projected Rankine coal SRMC from around 280 to 140 $/MWh.
- Wind LCOE $10/MWh higher case assumes wind is around $94/MWh after firming (compared to around $84/MWh in the base case).
- Faster growth case assumes demand in 2025 is consistent with the projected level for 2026 in the *Mobilise to Decarbonise* case in Whakamana te Mauri Hiko report by Transpower (i.e. higher case and demand growth arrives 12 months early).

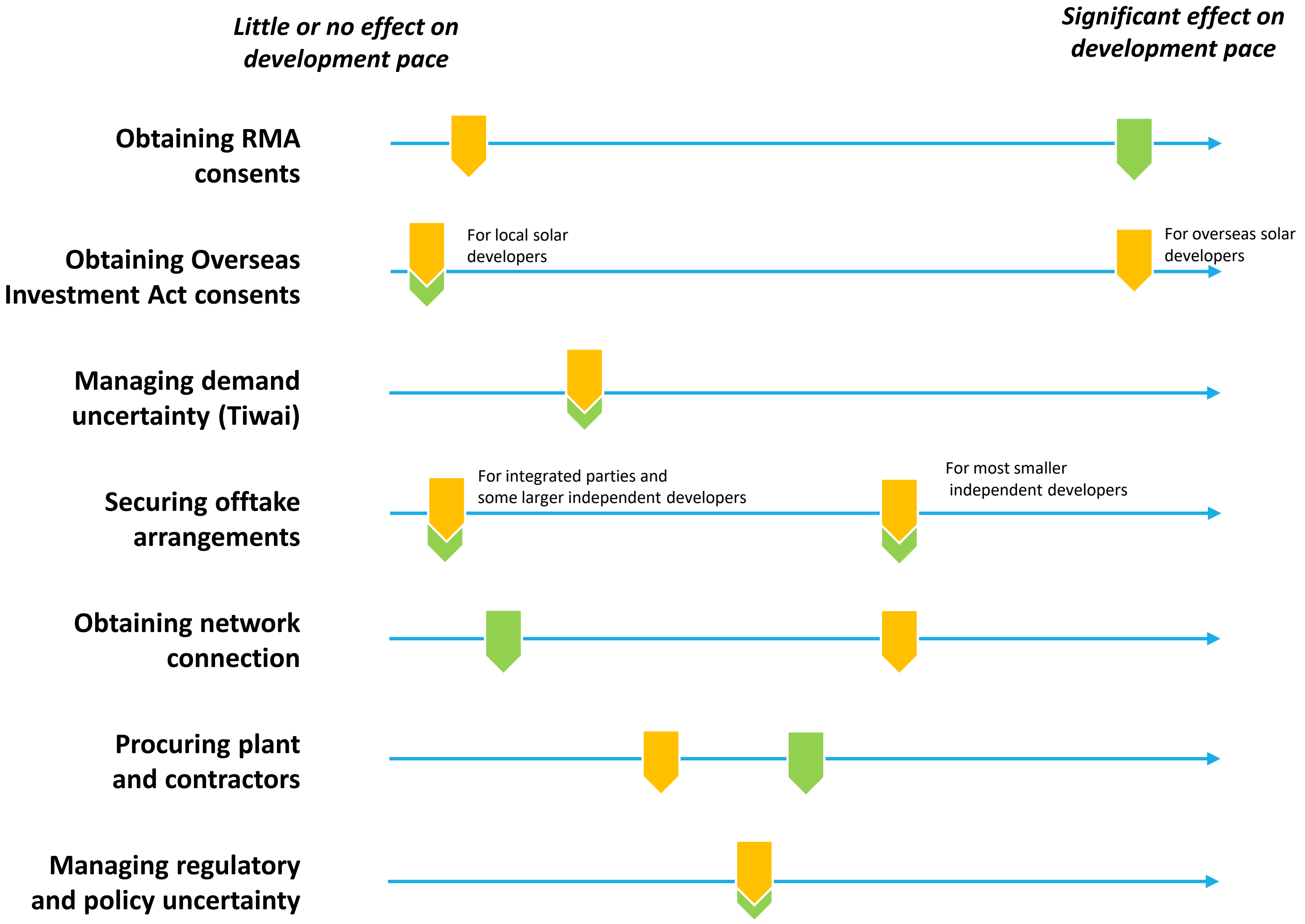
Why is additional investment not coming forward faster?

Developers generally see overall environment as attractive, but cite following factors as impediments to achieving greater pace

Ratings are based on interview responses and reflect broad themes. Contrary views were expressed in some cases.

Ratings only shown for solar and wind developers because there were too few responses to assess views for other types.

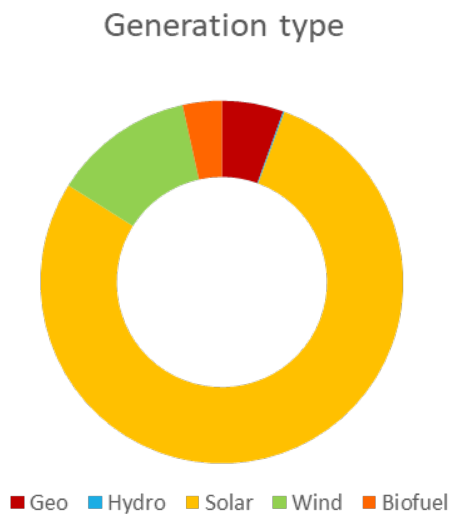
See following slides for more detail on each topic.

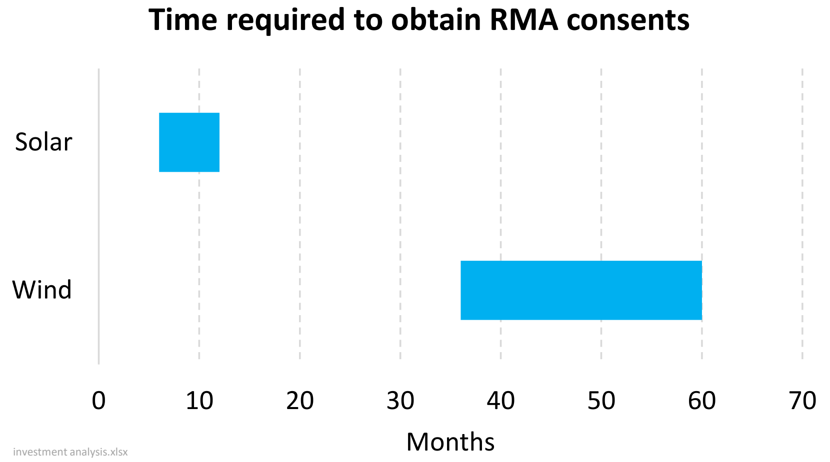


RMA requirements have a major effect on development pace for wind projects

Key points

- Wind projects typically require 3+ years to obtain Resource Management Act (RMA) consents – in part because of the need to collect ecological data over one or more biological seasons prior to making an application.
- This generally means that unless an application has already been lodged, any new wind project will not be available before end-2025. This is a key reason that wind projects account for <15% of active projects (by GWh/yr volume) which can be developed prior to 2025.
- Solar projects are currently easier to consent than wind under the RMA – although some developers thought this might change as larger scale solar farms become more common.
- At present solar developers report that RMA consents can be obtained in 6-12 months, depending on the site. This means that solar could be a major contributor by 2025 if developers can get comfortable with the economics.
- In principle, there is a 'fast track' option that developers can apply for under the RMA. However, few developers thought it would be faster in practice and only two reported interest in using that option.





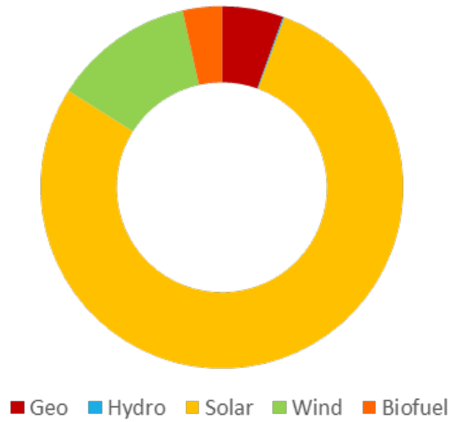
Notes
- Based on interviews with developers and other sources
- Percentages based on GWh/yr for actively pursued projects that could be developed by 2025.

Overseas Investment Act requirements may slow pace of solar development

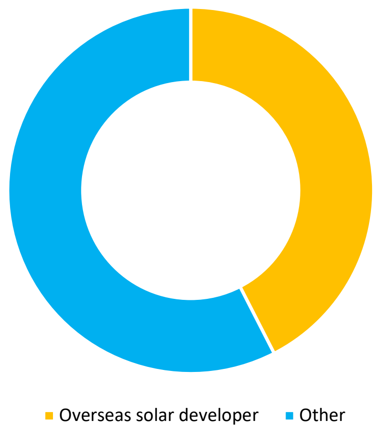
Key points

- Solar projects account for the lions share of generation that can be developed by 2025, and 42% of this developable volume is in the hands of overseas parties.
- A key issue for overseas developers is the application of the Overseas Investment Act (OIA). Solar projects typically trigger the 'sensitive land' provisions because they occupy rural land of more than 10 ha.
- Wind farms do not trigger these provisions because land easements are used, but we understand this option is not currently workable for solar farms.
- Developers report that the OIA provisions create cost and uncertainty and may ultimately block some business models because of:
  - The form of the national benefit test
  - The need to offer land on the open market prior to an overseas purchase (which may chill development effort pre-purchase and make it harder to demonstrate a national benefit)
  - The uncertainty about whether discretionary exemptions will be granted
- The significance of the issue is amplified because overseas parties appear to have greatest willingness to take offtake risk and (potentially) have faster build paths because they can leverage established relationships with equipment providers.
- This is an evolving issue. While many developers were optimistic that a workable approach would be found, none had identified a clear path as yet, and some rated the OIA process as the #1 impediment to faster development.

Generation type



Developer domicile



Notes
- Based on interviews with developers and other sources.
- Percentages based on GWh/yr for actively pursued projects that could be developed by 2025.
- Largest four suppliers and associated JVs are not included in 'overseas' category although they may require an approval under the Overseas Investment Act.

Tiwai uncertainty remains an issue, but is generally seen as less of a handbrake than the past

Key points

1. Concern about the future operation of the smelter remains an issue – noting that no further development would be required before 2025 if the smelter closes (see earlier slide on sensitivity cases).

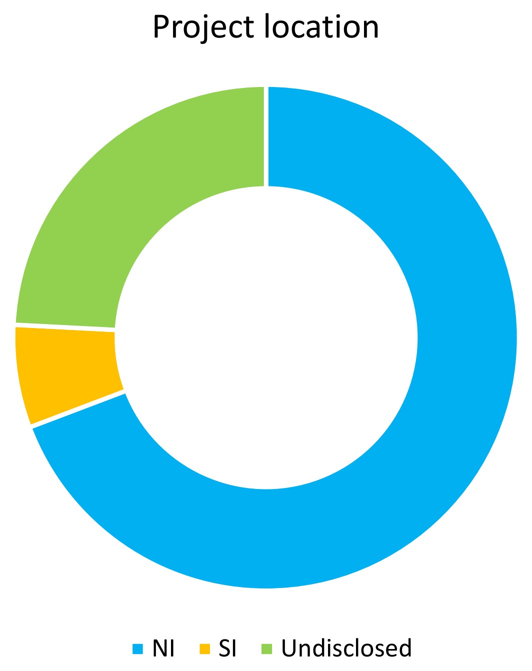
2. However, relative to discussions in 2021, developers are much less concerned than they were about smelter uncertainty.

3. In part this may reflect a concentration of development effort in the North Island, which would be partially insulated from a smelter closure. Interview data shows that ~90% of active projects that can be developed by 2025 (by volume) are in the North Island (where a location is known).

4. According to network operators, since early 2022 there has been increasing interest in South Island projects. This may indicate a growing expectation that the smelter will continue in operation.

5. Overall, Tiwai uncertainty is assessed as still being relevant, but appears to be less of a handbrake on new development than it was 12-24 months ago.

*since conducting our interviews, NZAS has announced that it has "begun exploring potential pathways with electricity generators for a future beyond 2024" (see www.nzas.co.nz/files/3841_2022072875725-1658951845.pdf).



Notes

- Locations are based on interview data and public sources.
- Percentages based on GWh/yr for actively pursued projects that could be developed by 2025.

Some independent developers are signalling willingness to take a degree of offtake risk – a notable difference to the past

Key points

1. Integrated developers (i.e those with other generation and/or retail) typically expressed willingness to build prior to securing specific sale contracts. This finding aligned with feedback in 2021 interviews.

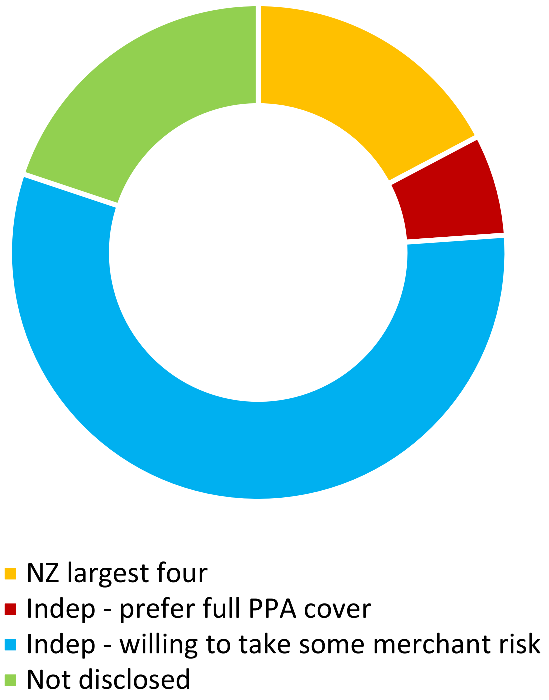
2. Historically, most non-integrated parties have been reluctant to bear offtake risk and viewed a power purchase agreement (PPA) as a pre-requisite to final investment decision.

3. While many independent developers retained this view (~10% of energy volume), others were willing to bear some risk. In particular, independents accounting for over 50% of project volumes said offtake agreements are not a pre-requisite to investment decisions. Some independents also stated a willingness to manage offtake risk via bilateral contracts, ASX futures and/or industrial sales, rather than PPAs. Having said that, access to firming products (e.g. caps) appears to be emerging as a key issue for independent developers of solar/wind.

4. The evolution of views among independents appears to reflect:
   - Interest in NZ from relatively aggressive larger developers who are well-capitalized and not reliant on project finance for funding
   - Experience gained by parties in overseas markets where developers have built projects before securing full sales agreements for a project's output
   - Greater comfort based on market soundings that customers will be willing to enter into contracts once a project is completed.

5. It is too early to know if this change will be borne out, but if it occurs there are potentially significant competition impacts, as large incumbents would have less ability to influence the rate of new generation build through via offtake or firming agreements.

Offtake arrangements



Notes
- Based on interview data.
- Percentages based on GWh/yr for actively pursued projects that could be developed by 2025.

It is unclear whether large incumbent suppliers are seeking to prolong the period of elevated wholesale prices

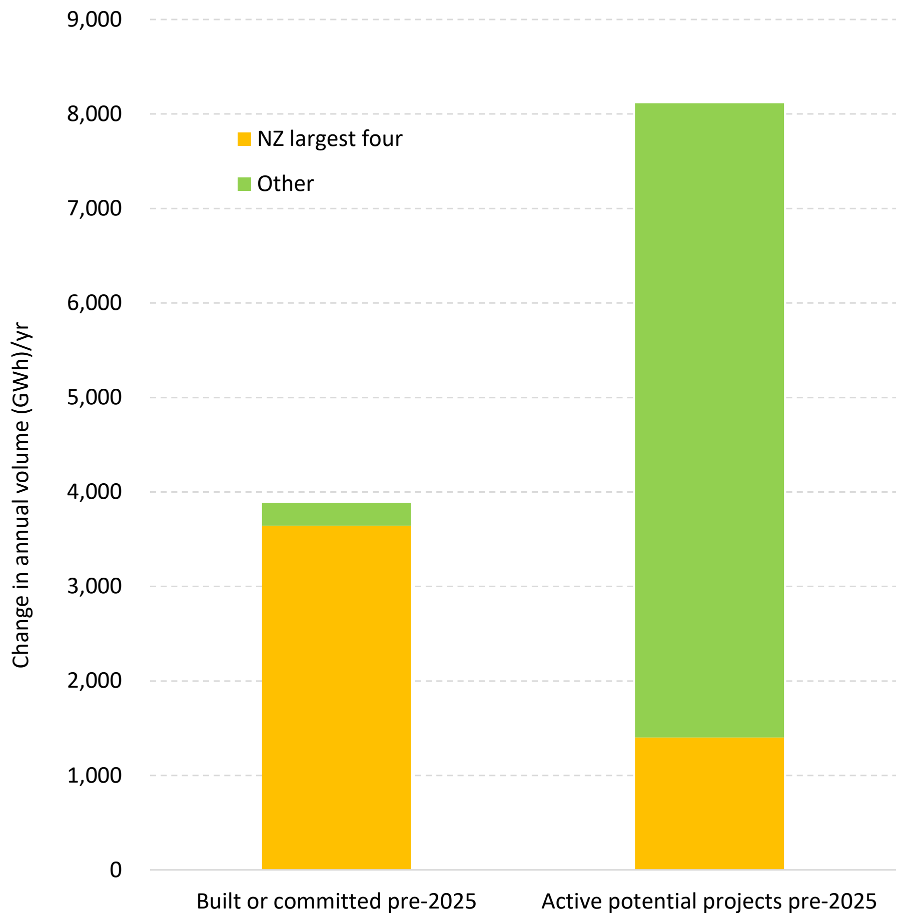
Key points

1. The four largest generators have significantly lifted their development efforts in recent years – with major committed projects underway and more potential developments under consideration. While these factors should reduce wholesale price pressures, it is unclear whether major suppliers' investment pace is being tempered by cannibalization concerns.

2. Such concerns can arise due to the depressing impact a new project may have on revenue from existing generation in an incumbent developer's portfolio. If a cannibalization effect applies, an incumbent supplier can be better off by delaying or foregoing investment, even though the project is economic it is own right.

3. If competitive pressures in the investment arena are sufficiently strong, the cannibalization concern will not arise. This is because any incumbent generator that delays its own investment will risk ceding the opportunity to a competitor (another incumbent or a new entrant).

4. There was no clear evidence that incumbent suppliers' own projects were being held back by cannibalization concerns. However, there were mixed reports about treatment of independent developers by major generators. Some responses suggested independents found it hard to attract interest from major generators, even with apparently attractive projects/power purchase offers – possibly due to cannibalization concerns. It was not possible to definitively test the strength of such claims due to information gaps. However, based on underlying incentives, the concern appears valid and likely merits closer monitoring.



Notes
- Largest four suppliers = Contact, Genesis, Mercury, Meridian

Connection is often a critical path item for solar projects – and some developers fear grid capacity will become a bottleneck in future years

Key points

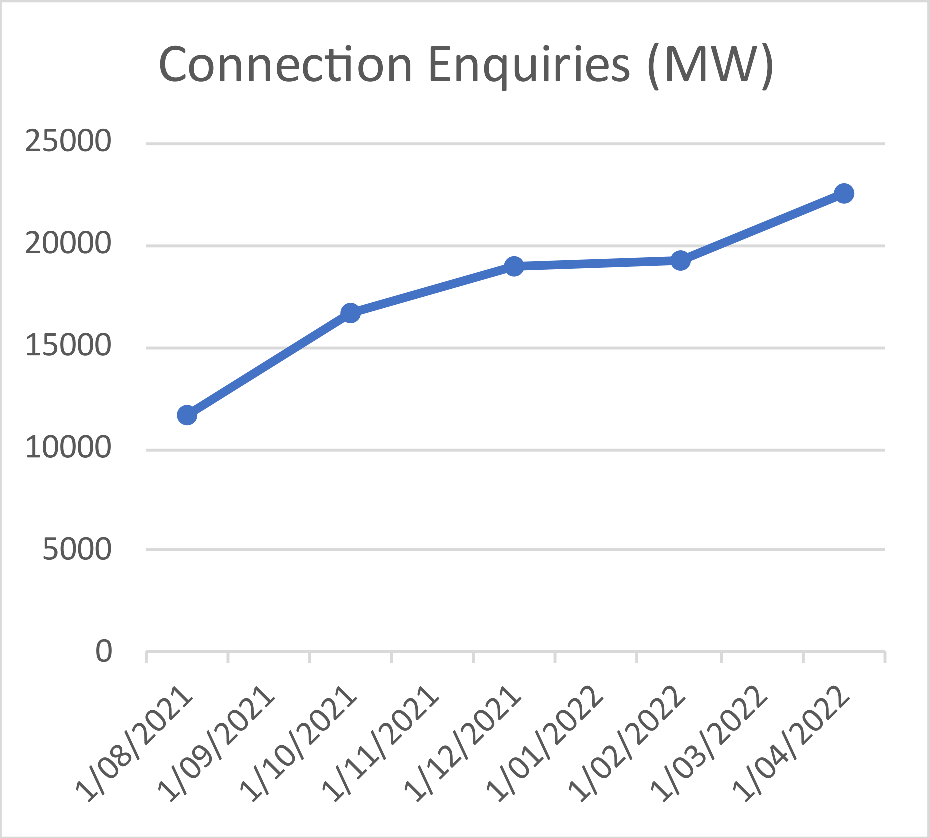
1. Developers generally recognised the need for connection studies as part of the suite of work needed to assess project feasibility.

2. However, developers often expressed frustration about current processes for assessing/approving connections including:
   - Delays in getting studies done due to shortages of specialist service providers
   - Apparent duplication of work in some cases where competing developers are assessing much the same opportunity
   - Some overseas developers consider NZ connection processes (especially at distribution level) could be streamlined – e.g. they point to greater use of standards and less requirement for bespoke analysis in some other countries
   - Slow responses from distributors in some cases

3. Looking further ahead, some generation developers expressed concern that grid development may become a bottleneck – especially given the much longer lead time for material grid expansion (~7+ years) compared to generation (18 months for solar, longer for wind).

4. Some parties suggested that greater transparency around potential developments would assist coordination, citing a 2019 NEM rule change as an example.

5. Some parties suggested that the benchmark transmission agreement be updated to streamline step-in rights for generation financiers – this issue is seen as an impediment for some independent developers.



Notes
- Source – Transpower's connection enquiry data

New generation build costs have been under upward pressure – these are expected to ease over time but complicate decision making for developers

Key points

1. As noted earlier, the cost of building new supply has been under strong upward pressure. Key drivers include supply chains that are stressed by the post-Covid restart, the Russia-Ukraine war and other economic disruptions (shipping shortages etc).

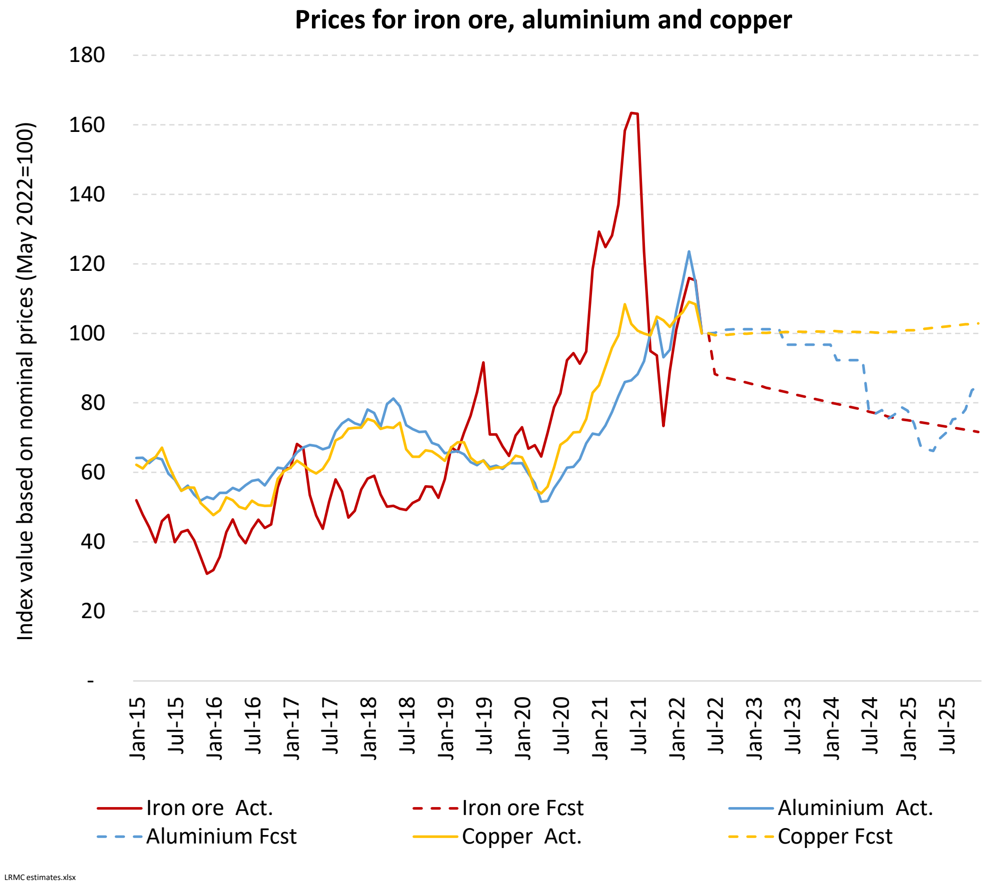
2. Developers also noted that local contractors are currently stretched by full order books and labour shortages – making it harder to get competitive offers for construction and civil works.

3. Developers noted that renewable projects are almost entirely upfront capital expenditure – locking in a high cost at the outset increases the likelihood of sub-economic returns, all other factors being equal.

4. Most developers expect these cost pressures to rebalance over time, but it may take many months or years. For example, forward prices for iron ore (a key input for steel) show a declining profile over next 3 years (see chart).

5. Furthermore, solar and wind technology are expected to improve further – which should lower per unit generation costs over time.

6. Developers say these factors mean they need to carefully weigh the value of waiting (when build costs may be lower) versus the value of building sooner (when revenues in early years may be higher than the long run average).



Notes

- Forward prices for iron ore, copper and aluminium were downloaded in late June 2022. Iron ore is used rather than steel because prices for the latter were not quoted to 2025.

If developers can obtain some near term revenue uplift, this can help to offset cost pressures

Key points

1. Project investment decisions are based on expected revenues over 25 years or more. Because ASX futures prices only extend ~3 years ahead, they have limited *direct** impact on most investment decisions.

2. Having said that, if developers can build quickly and capture some of the prevailing premium in prices, this should significantly improve project economics.

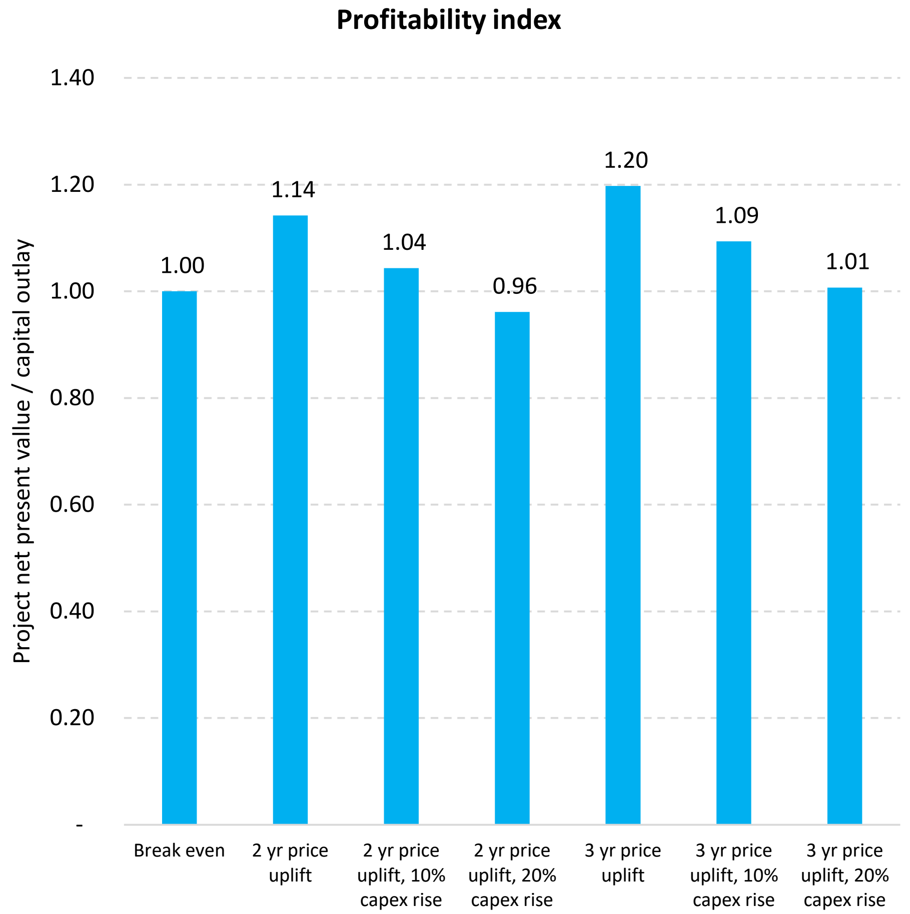
3. This view is supported by analysis of profitability indices (PI = the ratio of project net present value / capital outlay where 1.0 = breakeven).

4. The chart shows the effect of receiving forward curve prices for a project that would otherwise just breakeven. If the project can capture two years of higher prices, it would lift the PI to 1.14. Similarly, capturing three years of high prices would lift the PI to 1.20.

5. Another implication of this analysis is that projects may be able to withstand some higher build costs, provided they can capture higher electricity prices in the early years. For example, a project that experiences a 10% rise in capex (relative to a breakeven base case) could still be profitable if it can get earn some premium revenues in the early years. Conversely, a project with 20% higher costs could need a longer period of premium revenue to breakeven.

6. These observations may be especially relevant to the relative attractiveness of wind and solar projects – in general solar appears to have slightly higher costs than wind projects but can probably be developed more quickly.

*the ongoing availability of forward prices can help developers with their investment decisions.



lrmc estimates.xlsx

Notes
- Calculated for notional solar project using simple ungeared model. Project assumed to have 25-year life, initial capital cost that is 84% of project lifetime costs (in present value terms) and using 6% real discount rate.
- Breakeven price is assumed to be 84 $/MWh at gate. Scenarios with price uplift are based on ASX forward curve for 2024 and 2025 as at July 2022 and converted to real terms assuming 2% inflation. The 2 yr price uplift scenario assumes 170 $/MWh in first year, and 148 $/MWh for second year. No ASX price is yet published for 2026. The 3 yr price uplift scenario assumes the price is 148 $/MWh in year three. Prices in all other years across all scenarios are assumed to be at breakeven level for new supply of 84 $/MWh (real).

Policy and regulatory uncertainties were raised by many developers as a concern

Key points

1. Regulatory and policy predictability were seen as important for many developers, particularly the need to avoid measures or actions that increase longer term uncertainty.

2. Overseas parties rated NZ as being attractive relative to many other jurisdictions – citing strong climate action policies, clear market frameworks with few subsidies (the form and level of which can be changed easily and therefore create uncertainty), and low corruption.

3. Many of the overseas parties 'discovered' the opportunity to develop in NZ by chance (e.g. there were NZ staff members of offshore developers who returned to wait out the pandemic and became aware of local development potential). NZ appears to still have a relatively low profile as a destination for renewable (especially solar) investment.

4. Many parties noted that existing regulatory arrangements are not well suited to developing renewable generation 'at pace' – with the Resource Management Act and Overseas Investment Act attracting most comment.

5. Some parties felt that NZ could draw more heavily on overseas experience in areas that will become more important, such as ensuring timely grid development and providing for offshore wind development (e.g. a regime similar to the Crown Minerals Act).

6. Many parties also referred to key decisions coming up which they are watching closely – in particular around the NZ Battery project ('Onslow').

Areas for potential consideration

While policy responses are outside the scope of this report, the following options have been raised by parties for potential consideration

Potential actions to consider	Rationale
Encourage distributors to make greater use of connection standards where possible rather than requiring bespoke analysis of specific equipment/plant. Update benchmark transmission agreement to streamline step-in rights for financiers Assess whether transmission investment timeframes will hinder generation development.	Minimising undue frictions around connection arrangements will assist timely and efficient generation investment, particularly as many of the smaller scale projects are seeking connection at the distribution level.
Improve availability of information on future shape (not just level) of spot prices (e.g. forward prices for caps or 'peak' products).	ASX provides useful information about baseload prices, but solar/wind developers also need information on likely 'shape' of prices. Better information would assist developers of intermittent renewables and customers with pricing/negotiation of offtake agreements.
Improve public information on potential future demand and supply changes.	Information sources are fragmented making it harder for parties to determine when and where to deploy their development effort. Consider whether an annual report like NEM SOO would be useful.
Require major generators to deal with independent developers in good faith and have codified procedures for interacting with them to promote even handed treatment. Formally monitor how major generators are interacting with independent generators, e.g. how they respond to offers to sell energy via power purchase agreements etc. Monitor for anti-competitive behaviour by major portfolio generators such as 'land banking' of projects.	Threatened or actual entry by independent generators is likely to provide an important source of competitive pressure in the sector. Arguably, major portfolio generators may be able to hinder independent entry, for example by refusing to make any 'firming' products available on reasonable terms, or by favoring development of internal projects even though independent developers are offering supply from equivalent projects with lower costs.
Work with MBIE/Minister to actively promote NZ to international generation developers.	Increase competitive tensions, noting international parties often have scale and strength to provide real competitive pressure.
Engage with relevant agencies to ensure electricity sector implications of environmental consent frameworks are well understood (e.g. RMA reform).	RMA processes are a key factor affecting the rate of renewable development and electricity sector decarbonisation.
Engage with relevant agencies to ensure electricity sector implications of overseas investment regime are well understood.	Addresses a key issue for overseas solar developers who account for large proportion of projects in pre-2025 pipeline. Facilitates competition from parties that are likely to be well placed to compete.
Engage with other agencies (e.g. MBIE, Treasury) to ensure electricity sector implications of government policy are well understood.	Ensure MBIE and other key agencies understand importance of regulatory predictability.
Engage with GIC/MBIE to ensure electricity sector implications of fuel (especially gas) competition issues are well understood.	Fuel costs/uncertainties affect generation costs for electricity, and volume of new renewable generation that is economic to develop.

Assumed capacity factors

Biofuel	60%
Geo	95%
Hydro	50%
Offshore wind	57.5%
Onshore wind	40%
Solar	20%

Notes

- Manawa and Nova are not included as "NZ integrated" parties as their retail base is fairly small.
- 25% overseas ownership has been chosen as the threshold for developers categorised as "International" as this is the threshold at which a company is considered an "overseas person" under the Overseas Investment Act. Note that listed integrated parties with more than 25% overseas ownership are not counted as "international" for this purpose.
- Where developers provided a yearly generation output figure (in GWh/yr), we have used this figure. In other cases we have calculated generation output based on the capacity of the plant (in MW) using the assumed capacity factors on this slide.
- "Wind" refers to onshore wind. Offshore wind is specified as such.

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