www.concept.co.nz

Review of generation investment environment

August 2021

About Concept Consulting Group Ltd

We have been providing useful, high-quality advice and analysis for more than 20 years. Our roots are in the electricity sector and our practice has grown from there. We have developed deep expertise across the wider energy sector, and in environmental and resource economics. We have also translated our skills to assignments in telecommunications and water infrastructure.

Our directors have all held senior executive roles in the energy sector, and our team has a breadth of policy, regulatory, economic analysis, strategy, modelling, forecasting and reporting expertise. Our clients include large users, suppliers, regulators and governments. Our practical experience and range of skills means we can tackle difficult problems and provide advice you can use.

For more information, please visit www.concept.co.nz.

Disclaimer

Executive summary

2023 and 2024 contract prices are above estimated cost of new supply

In a workably competitive market, electricity contract prices over the longer term are expected to trend towards the cost of new electricity supply. This is because any sustained deviation between contract prices and new supply costs would be expected to trigger a correcting counteraction (via investment/disinvestment in generation or demand or both).

For the 2022 year a comparison of contract prices and new supply costs is not particularly meaningful because of the lag between new generation decisions and when the resulting output becomes available. However, further investment could be committed in 2021 and (potentially) be available in 2023 or 2024. And yet the contract price premium is very significant in 2023 and 2024 (~50% above the cost of new supply). This raises the question of why contract prices are so much higher in 2023 and 2024 than the estimated cost of supply.

Key reasons for gap between contract prices and new supply costs

In summary, we think the divergence between 2023 and 2024 contract prices and new supply costs is primarily driven by the pipeline of investment-ready projects having become very thin. Among larger consented projects, each faces specific issues which mean that investment decisions within the next 12 months appear unlikely. Moreover, even if a project was greenlighted immediately, most of these larger projects would take till 2024 or beyond to come onstream.

As a result, supply from new projects which have yet to be consented (or which require consent amendments) will be important. The need for new consents adds time to the development process and means that commissioning before 2025 is very challenging.[1] The key exception is solar farm development, which can be consented swiftly and built quickly.

Another likely contributing factor is uncertainty of various types in the investment environment (affecting projects in different ways). Furthermore, the relatively thin pipeline for new supply may be weakening the incentive on existing players to commit new investment in a timely manner.

Investment environment appears to be improving

Having said that, there are signs the investment environment is improving. Development interest (especially in solar farms) is surging, concern about a Tiwai smelter exit has reduced and the demand outlook is strengthening. In this context it is notable that Transpower reports connection enquiries for generation (excluding GXP enquiries from EDBs) have risen almost ten-fold over the past two years.

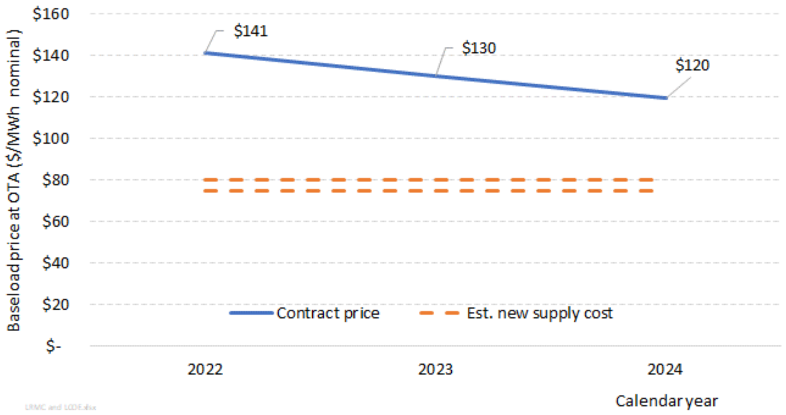
[1] Though not impossible – for example the Kaiwaikawe project is targeting consents in late 2021 and commissioning in early 2024.

1 Contract prices and cost of new supply

1.1 Contract prices are above estimated cost of new supply

Figure 1 shows forward contracts prices for 2022 to 2024[2] and the estimated cost of new supply ($75-80/MWh)[3]. This new supply estimate assumes the next increment of supply will be available at costs close to those reported for recent geothermal and wind projects and has been converted into baseload equivalent terms at Otahuhu.

Figure 1: Prevailing contract prices and estimated cost of new supply



Contract prices materially exceed the estimated cost of new supply for all contract years until 2024 (contract price data is not currently available beyond that year).

In a workably competitive market, electricity contract prices over the longer term are expected to trend towards the cost of new electricity supply. This is because any sustained deviation between contract prices and new supply costs would be expected to trigger a correcting counteraction (via investment/disinvestment in generation or demand or both).

For the 2022 year a comparison of contract prices and new supply costs is not particularly meaningful because of the lag between new generation decisions and when the resulting output becomes available. However, further investment could be committed in 2021 and (potentially) be available in 2023 or 2024. And yet the contract price premium is very significant in 2023 and 2024 (~50% above the cost of new supply). This raises the question of why contract prices are so much higher in 2023 and 2024 than the estimated cost of supply.

1.2 Possible reasons for gap between contract prices and new supply costs

We have identified a range of potential explanations for the apparent gap between contract prices in 2023 and 2024 and the cost of new supply:

- Futures prices in 2023 and 2024 may not be reliable for investment decisions
- Existing consented (and uncommitted) projects may have specific issues which hinder quick investment decisions

[2] Prices are for Otahuhu baseload calendar strip futures contracts at market close on 11 August 2021.

[3] This estimated cost of new supply reflects average reported costs for recent wind and geothermal projects, adjusted into baseload equivalent terms at Otahuhu. Note that for wind generation the adjustment into baseload equivalent terms appreciably lifts the 'headline' cost of non-firm wind generation. The cost estimate is consistent with longer-dated forward contract prices in 2018 before the gas market disruptions occurred and available external estimates such as broker reports.

- The time needed to obtain new consents and construct plant may make it difficult to bring new plant onstream before 2025
- Regulatory and market uncertainty may be hindering investment decisions
- Vertically integrated parties may be reluctant to increase their generation portfolio unless matched to their retail base
- Larger existing generators may have weaker investment incentives than new or smaller parties
- Investors may have difficulty in obtaining sufficient revenue certainty and hence capital
- Cost pressures may be hindering investment
- A lack of grid capacity may be hindering investment.

To help gauge the importance of these factors, we interviewed industry parties (including gentailers, independent generators, representatives of large electricity users, and Transpower) on the investment environment. Appendix 1 summarises the feedback and Appendix 2 lists the parties we interviewed. In the next section we set out our views on the relevance of each factor, based on our own analysis and industry feedback.

2 What explains the gap between costs and contract prices?

Table 1 summarises our view (as well as industry views) on which factors best explain the difference between contract prices in 2023 and 2024 and new supply costs.

Table 1: Potential factors contributing to gap between contract prices and cost of new supply

Factor	**Industry views**[4]	**Our view**	
		Is it a factor?	***Comment***
1. Futures prices in 2023 and 2024 may not be reliable for investment decisions	Futures prices were generally seen as strongly signalling a need for further investment. However, there was also a view that longer dated futures may be unduly influenced by shorter-term factors, including current hydrology and gas supply conditions.	✓	Many industry interviewees acknowledged that futures prices are signalling the benefit of new investment for projects that can come onstream before 2024 (noting this may be difficult as discussed below). In addition, while recent hydrology conditions may be affecting sentiment and out-year prices, we do not consider that it would explain a 50% premium to new supply costs. In this context we note that prices for 2021 contracts have declined substantially as hydro conditions improved but there has been little change in the 2024 contract price.
2. Existing consented (uncommitted) projects may have specific issues which hinder quick investment decisions	Some existing consented projects are no longer attractive for location and/or technology reasons.	✓✓✓	While there is a relatively long list of consented projects, many lack 'modern' consents or face issues that hinder make quick investment decisions. For example, the five largest consented (but as yet uncommitted) projects are: • Castle Hill wind farm (860 MW) requires a costly transmission connection and is in the Manawatu/Tararua region. As a result, it may be less financially attractive than wind generation located elsewhere. • Otorohanga peaker (360 MW) is a thermal plant and decisions are likely to be affected by the government target of achieving 100% renewable electricity by 2030. • Kaiwera Downs wind farm (240 MW) is in the region that would most affected if the Tiwai smelter exits (and may need to be re-consented to allow for new wind technology). • Puketoi wind farm (201 MW) is consented for larger turbines. However, it requires a transmission extension to be built and is in the Manawatu/Tararua region which has most

[4] This column provides a summary of views held by the industry parties we talked to and will not reflect each individual party's view.

Factor	Industry views[4]	Our view	
		Is it a factor?	*Comment*
			of NZ's wind generation capacity. In addition, Mercury (the developer) has recently made other sizeable investments (Turitea North and South, Tilt and (conditionally) the Trustpower retail business) which require capital and management attention. • Mahinerangi II wind farm (160 MW) is in the region which would be most affected by a Tiwai's smelter exit.
3. The time needed to obtain new consents, construct plant, and/or get connection may make it difficult to bring new plant onstream before 2025	It can take up to five years to develop a wind farm. The development lead time is shorter for solar farms, but they have only recently attracted significant developer interest.	✓✓✓	The lead time for developing wind and geothermal projects means that any project which is not already consented is unlikely to be fully operational before early 2024. The timeframe for consenting and constructing solar farms is shorter. However, to date it appears that economics has favoured wind over solar. This may be changing as shown by the very substantial step up in interest by solar developers and recent Kapuni solar farm. If solar economics prove to be attractive, this could be a potential 'game changer' and significantly shorten development pipelines. Having said that, large solar farms would likely have longer lead times than 12 months if they require significant grid investment.
4. Regulatory and market uncertainty may be hindering investment decisions	Uncertainties are an issue – especially around government policy and potential for change. Uncertainties around the rate of future electricity demand growth and what the TPM will look like may also be delaying some investment decisions. Uncertainty around Tiwai	✓	Uncertainties of one type or another are clearly affecting projects. For example, projects in the lower South Island are affected by uncertainty about the Tiwai smelter. Similarly, carbon and renewables policies are likely to affect investment decisions for new thermal generation plant. More generally, uncertainty around government policy could deter decisions to invest in new generation. Having said that, uncertainty does not appear to have deterred investment decisions to date. In 2021, we estimate that over $1.1 billion has been committed by investors for new generation plant which is scheduled to come on stream in 2023 or 2024.[5]

[5] Based on the disclosed capital costs of Harapaki and Tauhara I and assuming Kaiwaikawe has the same cost as Harapaki in $/MW terms.

Factor	Industry views[4]	Our view	
		Is it a factor?	***Comment***
	smelter's future has reduced but remains an issue especially for lower South Island projects.		Similarly, uncertainty has not deterred other investment decisions in the sector (e.g. the purchase of Tilt by Mercury which was also presumably affected by many of the uncertainties noted above). However, it is likely that uncertainty about future demand growth may have delayed some investment decisions.
5. Vertically integrated parties may be reluctant to increase their generation portfolio unless matched to their retail base	Some parties believe gentailers will only grow their generation portfolio in line with growth in their own retail base.	-	This may have been an issue in the past but recent evidence suggests it is less relevant. For example, Contact committed in January 2021 to develop the Tauhara I geothermal project, and only later (in August 2021) entered into an PPA with Genesis to sell some of the project output. Similarly, Trustpower announced in mid-2021 an intention to fully demerge its generation and retail operations. Part of the stated rationale for the demerger is to allow the new generation arm to focus on developing generation projects.
6. Larger existing generators may have weaker investment incentives than new or smaller parties	One party considered that existing players with larger portfolios may rationally delay generation investment if delay will raise returns on existing plant.	✓	Participants with existing generation portfolios are likely to consider the effect of a new investment on their existing business, as well as the incremental revenues and costs for the new project itself. If a new project reduces the sale volume/prices for existing generation, then such 'portfolio effects' will be a negative factor for overall economics. However, the size of such portfolio effects turns on the strength of competition. If delaying an investment simply results in another party moving ahead with its project, then the portfolio effect will be zero. In the current context with a limited menu of investment-ready projects (especially by independents), it is plausible that portfolio effects are relevant. Having said that, the threat of entry by independents (especially solar if it proves to be economic) could rapidly alter the dynamic. On balance we think this factor could be relevant but it is hard to clearly assess its magnitude.
7. Investors may have difficulty in obtaining	Independent investors need to enter into a PPA	-	This has possibly been a factor, but there is evidence the situation may be improving. In particular, Genesis (an integrated party) has signed PPAs with an independent supplier (Tilt was independent

Factor	Industry views[4]	Our view	
		Is it a factor?	***Comment***
sufficient revenue certainty and hence capital	to be able to obtain capital for projects. Some parties reported it was difficult to get acceptable PPAs with gentailers. PPA market was improving though.		at the time) and a competitor (Contact). Genesis is also reported to be negotiating with other potential suppliers for further PPAs. Similarly, Trustpower's planned demerger suggests it considers that vertical integration is not value enhancing for its business and that new generation developments can be underpinned by PPAs or other contractual options (including sales to large industrial and commercial customers). Finally, a group of larger industrial users has been seeking to negotiate a PPA (or multiple PPAs) with potential suppliers, and if concluded this may underpin new investment.
8. Cost pressures may be hindering investment	Some cost pressure (due to increasing commodity prices, labour shortages, global logistics and supply chain issues, and increasing health and safety costs).	-	A number of interviewees cited emerging signs of cost pressures. This reflects tight conditions in civil construction sector with many infrastructure projects underway in New Zealand and growing global demand for wind and solar generation plant. On the other hand, there are some countervailing forces, especially technology improvements which affect plant costs. Overall, we are not aware of any investment decisions that have been delayed due to this issue. We therefore rate this as a possible issue for the future rather than a likely factor.
9. A lack of grid capacity may be hindering investment	Investment may be constrained by tight grid capacity in some areas (e.g. Northland).	-	This may be an emerging issue in some parts of the country (e.g. Northland). However, it appears that developers have typically been targeting their effort into areas where there is currently some network headroom. Hence, this issue is unlikely to constraint investment in the short-term. However, looking further ahead it is quite possible that this will become more important as networks (both the grid and distribution networks) see 'in-fill' generation development and use up the available headroom.

2.1 Key reasons for gap

In summary, we think the divergence between 2023 and 2024 contract prices and new supply costs is primarily driven by the pipeline of investment-ready projects having become very thin. Among larger consented projects, each faces specific issues which mean that investment decisions within the next 12 months appear unlikely. Moreover, even if a project was greenlighted immediately, most of these larger projects would take till 2024 or beyond to come onstream.

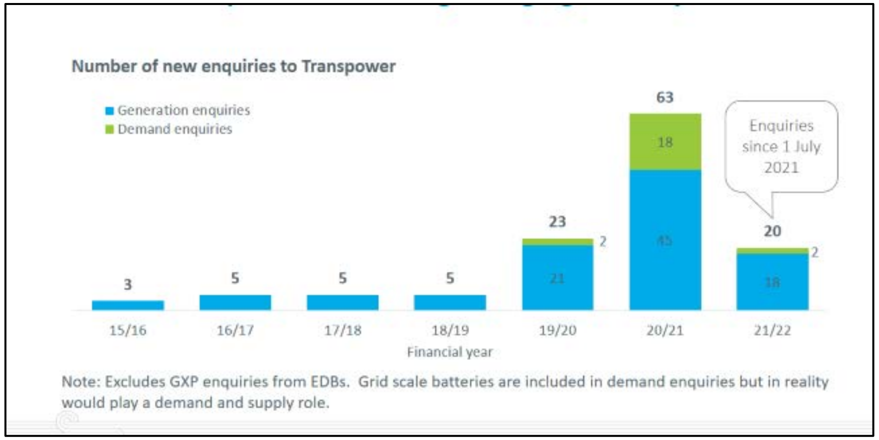
As a result, supply from new projects which have yet to be consented (or which require consent amendments) will be important. The need for new consents adds time to the development process and means that commissioning before 2025 is very challenging.[6] The key exception is solar farm development, which can be consented swiftly and built quickly.

Another likely contributing factor is uncertainty of various types in the investment environment (affecting projects in different ways). Furthermore, the relatively thin pipeline for new supply may be weakening the incentive on existing players to commit new investment in a timely manner.

2.2 Investment environment appears to be improving

There are signs the investment environment is improving. Development interest in solar farms is surging, concern about a Tiwai smelter exit has reduced and the demand outlook is strengthening. In this context it is notable that Transpower reports connection enquiries (excluding GXP enquiries from EDBs) have risen substantially over the past year or so. Obviously, the conversion rate from enquiries to projects will be less than 100%. In addition, Transpower has noted that while they have had lots of connection enquiries, few have yet to materialise as firm projects (although they expect this to happen in time). Nonetheless the greater number of enquiries is a strong sign that developers are more interested than in the past.

Figure 2: Connection enquiries have risen significantly



Source: Transpower

In 2020/21 connection enquiries for generation were almost 10 times higher than 2018/19. We note many recent enquiries were for smaller projects. However, Transpower has confirmed that in MW terms there has also been a material step-up in interest.

[6] Though not impossible – for example the Kaiwaikawe project is targeting consents in late 2021 and commissioning in early 2024.

Appendix 1 – summary of interview feedback

Futures prices for 2023 and 2024 may not be reliable for investment decisions

There was a widespread view that futures prices are currently providing a strong investment signal. However, a number of parties cautioned that investment decisions are based on expected cashflows over 25-30 year project lives. While elevated prices in the front end of a project would be positive and provide some cream, they would be expected to have a modest effect on overall economics.

Some parties said that futures market prices for longer dated contracts (2023 and 2024) can be unduly influenced by recent or current conditions. In particular, one party considered that futures prices for out-years are generally driven by current hydrology and thermal fuel market conditions. They considered this to be irrational given that hydrological conditions tended towards average levels over time.

Lack of suitable RMA consents

There was a widespread view that there are relatively few viable projects with a full set of Resource Management Act (RMA) consents. While parties noted that there is a longer list of consented projects, many of these are no longer considered to be attractive due to their location and/or changes in technology. In addition, consents for some other projects have recently expired.

Some consented projects aren't in the best location

A number of parties told us that in the past windfarms were generally developed on the windiest sites. However, often these sites are more difficult to access (raising civil construction costs), may not be close to transmission lines, or be on the wrong side of potential transmission constraints. Many parties considered that it wasn't necessarily economic to build on the windiest site anymore[7], with accessibility and transmission issues of greater importance to project economics.

Some parties also suggested that investors have become more aware of the depressing effect on project revenues of having many windfarms in the same wind catchment. This arises if a new windfarm's output is highly correlated with that of other nearby windfarms and the dampening impact this has on spot prices when it was windy. This means, for example, that developing more windfarms in the Manawatu region may be less attractive due to the prevalence of windfarms in this region already.

Some consents don't allow for new (and more efficient) technology

Developments in turbine technology mean that taller wind turbines (around 160 metres) are typically more efficient, but many existing windfarm consents don't allow for turbines this high. Parties considered that modifying consents to allow for taller wind turbines can be challenging, with issues such as increased visibility effects to contend with.

Consenting a project takes time and re-consenting can take even longer

Industry parties provided a range of estimates on how long it takes to get resource consents for a generation project saying it was strongly influenced by the generation type. Estimates for windfarms varied between 18 months and 3-4 years, depending on the extent of community

[7] This is partly due to developments in turbine technology, which we discuss in the next subsection.

support/opposition and the hearing processes used for the application. Parties indicated that solar plant are relatively easy to consent at present and are often non-notified, with consents available within 6-12 months.

Several parties considered there were difficulties with re-consenting of existing generation facilities (noting that many existing consents expire over the next five years). One party said that they had to put considerable time and effort into keeping a consent, while another party said that they often need a five-year lead time for re-consenting. One party considered there were specific issues with re-consenting hydro stations—re-consenting often led to lower allowable water take and less flexibility of operation.

Some parties stated that monitoring of sites is often necessary before applying for a resource consent. One industry party believed that the Department of Conservation (DOC) may seek to increase the level of baseline ecology monitoring before a resource consent application is made. This may not only contribute to longer development cycles, but also raise costs, increase uncertainty, and could hinder efficient and steady development of renewable generation.

While industry parties thought that obtaining a resource consent took time, they generally thought that obtaining resource consent was not a key constraint for investment because parties could take that into account with pre-planning – i.e. ensure they have a pipeline of consented or near-consented projects available. Having said that, the recent change in the investment environment (from little or no growth to rising demand) meant that the pipeline is currently very skinny. This means there would likely be a catch-up phase as parties increased their development teams and put more effort into new projects.

Ventus Energy has publicly stated that they believe the expectations on studies required by councils has increased over time, making the consent process more difficult.[8]

Some parties also considered that the RMA process could be streamlined, and the government should be careful to ensure that the legislation to replace the RMA does not lengthen timeframes (either in the transition phase or over the longer term).

The list of consented investment-ready projects is currently thin

Table 2 lists generation projects that we're aware of and notes:

- their development and consent status
- any reasons why they may not be being progressed at this stage.

Examination of the table shows that while there is a relatively long list of potential projects, there are relatively few that are both consented and appear actionable in the short-term.

[8] www.kaimaiwind.nz (see news article dated 11 August 2021).

Table 2: Generation projects[9]

Project name	Type	Consented	Developer	MW	Comments
Castle Hill	Wind	✓	Genesis	860	• Consent expires 2023. • Located 20km northeast of Masterton in the Wairarapa. • In February 2021, Genesis said it had no immediate plans for Castle Hill, but it remained an option.[10] • In 2019, Genesis indicated that it would need to modify its resource consent for the project to reflect new technology if it ever went ahead.[11]
Otorohanga peaker	Gas	✓	Todd	360	• Consent expires 2027. • In October 2020, MBIE reported that Todd had said they could not advise on the likely timing of this project due to current market conditions, Tiwai closure uncertainty, carbon tax implications, and the bedding in of their recently commissioned Junction Road plant.[12] • Located close to transmission and gas pipelines.
Puketoi	Wind	✓	Mercury	318	• Located 40km south of Dannevirke in Manawatu. • Mercury has said it needs to take a close look at Puketoi given technology changes that have occurred since the project was granted consent in 2012.[13] • Mercury has said it will be working on the sequencing of its wind projects (including acquired Tilt wind projects). These projects

[9] Based on publicly available information. Details about projects are subject to change.
[10] https://www.wind-watch.org/news/2021/02/03/genesis-may-revive-plan-for-1-6-billion-wind-farm-at-castle-hill/
[11] ibid.
[12] p64, https://www.mbie.govt.nz/assets/2020-thermal-generation-stack-update-report.pdf.
[13] ibid.

Project name	Type	Consented	Developer	MW	Comments
					include Puketoi, Mahinerangi II, Kaiwera Downs, Tauhara repower, and Kaiwaikawe (formerly Omamari).[14] • Transmission infrastructure to serve the Turitea windfarm has been scaled for development at Puketoi.[15]
Kaiwera Downs	Wind	✓	Tilt[16]	240	• No recent information available on the status of this project. • In Southland. • Mercury has said it will be working on the sequencing of its wind projects (including acquired Tilt wind projects). These projects include Puketoi, Mahinerangi II, Kaiwera Downs, Tauhara repower, and Kaiwaikawe (formerly Omamari).[17]
Harapaki	Wind	✓	Meridian	176	• Committed. • Commissioning target: mid-2024. • Increased certainty around Tiwai's future (from the January 2021 announcement that Tiwai would continue operating until the end of 2024) allowed Meridian to commit to the Harapaki wind farm.[18]
Te Mihi expansion	Geothermal	X	Contact	165 - 180	• Application for resource consent was lodged in August 2021.
Mahinerangi II	Wind	✓	Tilt	160	• Mercury has said it will be working on the sequencing of its wind projects (including acquired Tilt wind projects). These projects include Puketoi, Mahinerangi II, Kaiwera Downs, Tauhara repower, and Kaiwaikawe (formerly Omamari).[19] • In Otago.
Tauhara	Geothermal	✓	Contact	152	• Committed. • Commissioning target: mid-2023.
Kaimai	Wind	X	Ventus	150	• Have applied for consent – expect decision by March 2022.

[14] Ibid.
[15] p3, https://www.mercury.co.nz/documents/j001205_mercury_interim_report_2021_a4_ll_pp7_med.aspx.
[16] Tilt's New Zealand operations and assets were acquired by Mercury in August 2021.
[17] https://www.energynews.co.nz/news-story/wind-energy/85698/mercury-scope-wind-project-sequencing
[18] https://www.energynews.co.nz/news-story/electricity-generation/83183/tiwai-suppliers-scoping-new-demand.
[19] https://www.energynews.co.nz/news-story/wind-energy/85698/mercury-scope-wind-project-sequencing.

Project name	Type	Consented	Developer	MW	Comments
					• In Bay of Plenty.
Central Wind Farm	Wind	X	Meridian	130	• Consent lapsed in 2020. • In Manawatu. • Meridian has said that the economic conditions required to build and operate the wind farm became unfavourable and hence it let the consents lapse. However, Meridian still considers it an excellent site and believe it can be a strategically significant development. Meridian has said that they plan to apply for a new consent for this site.[20]
Turitea North	Wind	✓	Mercury	119	• Committed. • Commissioning target: Q4 2021. • Partly commissioned in August 2021.
Turitea South	Wind	✓	Mercury	103	• Committed. • Commissioning target: Q2 2022.
Mokihinui	Hydro	X	Meridian	100	• Abandoned. The project received resource consent approval, but this decision was appealed to the Environment Court and ultimately Meridian ceased interest in the project before the Environment Court hearing.[21]
Mt Cass	Wind	✓?	Mainpower	93	• Construction start target: late-2021. • Commissioning target: 18 months from start of construction (approx. mid-2023).
Kaiwaikawe[22]	Wind	X	Tilt	75	• PPA with Genesis announced on 2 August 2021. • Hearing for consent set for mid-August 2021. Tilt hopeful of having resource consent in place by end of 2021. • Commissioning target: 2024. • In Northland (near Dargaville).

[20] https://www.meridianenergy.co.nz/who-we-are/our-power-stations/wind/central-wind
[21] p3, https://www.mbie.govt.nz/assets/hydro-generation-stack-update-for-large-scale-plant.pdf
[22] Formally known as Omamari.

Project name	Type	Consented	Developer	MW	Comments
					• Mercury has said it will be working on the sequencing of its wind projects (including acquired Tilt wind projects). These projects include Puketoi, Mahinerangi II, Kaiwera Downs, Tauhara repower, and Kaiwaikawe.[23]
Wairau	Hydro	✓	Trustpower	72	• Consent expires 2021 • In Marlborough.
Hurunui	Wind	✓	Meridian	70	• Consent expires 2023. • In Canterbury. • Meridian said in February 2021 that it would want to see stronger demand growth in the South Island before it develops more generation there.[24]
Tararua repower	Wind	X	Tilt	70[25]	• Consenting in progress? • In Manawatu. • Mercury has said it will be working on the sequencing of its wind projects (including acquired Tilt wind projects). These projects include Puketoi, Mahinerangi II, Kaiwera Downs, Tauhara repower, and Kaiwaikawe (formerly Omamari).[26]
Taumatatotara	Wind	✓?	Ventus	50	• Have sought non-notified variation to consent to increase size of turbines. • Hoping to start construction in summer of 2021/22. • Hope to be operational by beginning of 2023. • In the Waikato.
Arnold Valley	Hydro	✓	Trustpower	46	• Consent expires 2021 • Trustpower have indicated they are no longer pursuing this project.[27]
Kaitaia	Solar	✓	Lodestone	39	• Commissioning target: early 2022.

[23] ibid
[24] https://businessdesk.co.nz/article/infrastructure/dramatically-faster-consenting-needed-for-renewables-meridian.
[25] Tararua repower would increase capacity of Tararua wind farm from 161 MW to 231 MW (an increase of 70 MW).
[26] ibid
[27] p15, https://www.mbie.govt.nz/assets/hydro-generation-stack-update-for-large-scale-plant.pdf

Project name	Type	Consented	Developer	MW	Comments
Lake Pukaki (Gate 18)	Hydro	✓	Meridian	35	• Consent expires 2021. • In Canterbury.
Ngawha II (OEC5)	Geothermal	✓	Top Energy	32	• Top Energy commissioned first Ngawha plant in December 2020. • Ngawha II is consented subject to confirmation of the performance of the field (which is required to be monitored for three years (2021-2023).[28] • In Northland.
Maranga Ra	Solar	✓	Refining NZ	27	• Next to Marsden Point.
Ngakawau	Hydro	✓	Hydro Developments	24	• Consent expires 2026. • On the West Coast.
Pukenui	Solar	✓	Far North Solar Farm	16	• Construction started July 2021. • Commissioning target: early 2022.
Morley Road	Solar	X	Lightyears Solar	3	• Consent expected September 2021. • Construction expected to start Q1 2022. • Commissioning target: Q3 2022.
Naumai	Solar	✓	Lightyears Solar	3	• Construction expected to start Q3 2021. • Commissioning target: Q1 2022.
Komata North	Solar	?	Lightyears Solar		• Consent was expected July 2021. • Construction expected to start Q4 2021. • Commissioning target: Q2 2022.

[28] http://ngawhageneration.co.nz/wp-content/uploads/2021/01/Top-Energy_Ngawha-Commissioning_Web_small.pdf

Unwillingness to invest due to uncertainty

Some parties suggested that heightened uncertainty was hindering investment decisions. Key uncertainties suggested by parties included:

- government policy toward decarbonisation and the electricity sector
- the transmission pricing methodology (TPM)
- the rate of future electricity demand growth
- the future of the Tiwai aluminium smelter.

Uncertainty around government policy

Several parties expressed the view that uncertainty around government policy and the possibility of intervention made it difficult to plan and make long term investment decisions. Three parties considered that government policy and intervention risk was one of the biggest (if not the biggest) factors holding back investment. Uncertainty around government policy could delay decisions to invest in new generation and/or cause investors to require a higher return before committing investment.

Uncertainty about the TPM

Some industry parties felt that some forms of investment (particularly battery and solar investment) might be held back due to uncertainty about the exact form of the TPM and when change would occur. One party was particularly concerned about the impact the TPM might have on investment north of Auckland, while another party was concerned that the TPM could make the first-mover problem worse.

Uncertainty around underlying demand outlook

Most parties were expecting electricity demand to grow, although many considered there was substantial uncertainty around the rate of demand growth. One party thought that while decarbonisation was expected to drive demand growth from electric vehicles and use for space and water heating, there was potential for this to be offset (at least in part) by reduced electricity demand by some large industrial electricity users.

Two parties considered that demand wouldn't grow as fast as public forecasts indicated:

- one party considered there would be slight demand growth due to population growth but they didn't think demand would grow as fast as Transpower was predicting because some industrials were reducing electricity consumption and others were stopping operations completely
- another party didn't think demand would grow as fast as the Climate Change Commission was predicting.

Some parties indicated that this uncertainty about the rate of future electricity demand growth may be delaying some investment decisions—some investors may be waiting to see if demand ticks up before committing to projects.

However, one party considered that even if demand didn't grow we would still need further generation investment to replace thermal plant as it retires.

Uncertainty about Tiwai smelter future has reduced but remains an issue

Many parties considered that uncertainty around the future of NZAS's Tiwai smelter had reduced substantially following the January 2021 announcement that the smelter would continue operating until the end of 2024.

Furthermore, while uncertainty about the smelter's future remains beyond 2024, many parties considered that this would have a limited impact on investment decisions. Several parties thought that when looking at investments with a 30+ year lifetime, the potential closure of Tiwai was a small blip and participants would look through this when considering a project investment or power purchase agreement (PPA). As evidence for this view, parties pointed to announcements in 2021 that new generation was being committed which would come onstream shortly before 2025 (e.g. the Harapaki, Tauhara I, and Kaiwaikawe projects).

However, some industry parties considered there could be an impact in the short term—for example, an investor may decide to delay an investment decision to avoid it getting commissioned near or just after the end of 2024 (when Tiwai might exit). Industry parties also thought the Tiwai uncertainty was also likely to be having a bigger impact on investment plans in the South Island than in the North Island, particularly the lower South Island.

More generally, many parties considered the risk of market dislocation from a Tiwai exit was lower now than in the past. This was because there were credible prospects of other forms of demand, such as hydrogen production and data centres, that could offset some (or all) of the reduction in demand if Tiwai exited. In addition, underlying demand growth is expected to quicken in the next few years as decarbonisation gathers pace. This would mean that any temporary supply surplus is absorbed more quickly than in the (former) environment of little or no growth. Finally, many parties considered that Tiwai was more likely to stay than exit at the end of 2024.

Timeframes to construct and connect new plant

There are several steps that need to be taken to get a generation project built and commissioned—key steps include:

- monitoring site conditions
- design
- applying for and obtaining resource consents
- construction of plant
- establishment of connection to grid or local network (as required).

Industry parties noted that the time between an investor first considering a project and commissioning can be significant. For example, one party indicated that it can take five years to get a wind farm consented, constructed and operational, and that was assuming the investor encountered no significant roadblocks along the process. (Industry parties' views on the time taken to monitor sites and obtain consents were considered on page 9.)

For projects that are already consented, industry parties indicated that construction and commissioning will take approximately:

- 6-12 months for solar (multiple parties had this view)
- 12-15 months for thermal (only one party expressed a view)
- 18 months to 3 years for wind (multiple parties expressed views)
- even longer for geothermal.

Industry parties considered that the time taken to commission a consented project will also depend on the size of the project (larger projects usually take longer) and the complexity of the project. For example, a wind farm will take longer to construct if it's on a complex site (approximately 3 years) than a flat site with easy access (approximately 18 months to 2 years).

If significant works are required to establish a grid connection (e.g. major new transmission lines) parties indicated that the construction time will likely be longer than noted above. Some parties considered that connection is often the critical path item for solar developments and can take some time to get established.

Preference by vertically integrated parties to maintain balanced portfolios

Some parties expressed a view that the major vertically integrated (VI) suppliers prefer to keep a close balance between their generation and retail operations. Proponents of this view considered that the tendency can temper the appetite of VI participants to invest in generation when they have an otherwise economically attractive project. Instead, it was argued that VI participants will tend to delay their generation investments until they have sufficient 'internal' demand.

Similarly, it was argued that the preference to maintain an internally balanced business can lead to VI participants preferring internally developed projects over external sources (even if the latter have lower cost).

Impact of portfolio effects on existing generation

One party considered that established players face different incentives to new (or smaller) participants because they will rationally consider the effect of a generation investment on their existing portfolio. Furthermore, such portfolio effects are generally negative for large established participants because new investment will likely reduce market prices and/or reduce utilisation of existing assets (relative to a case where investment does not proceed).

Such effects can make any given investment less attractive for established players than equivalent independent parties. This in turn can mean that investment decisions occur later (when the system is tighter) if independent/smaller participants have difficulty competing in the new investment market.

Revenue stability and access to capital

Obtaining contractual revenue certainty is important for investors who don't have an internal retail business to smooth out spot market volatility. Without some form of forward revenue protection, developers would be unlikely to be able to access bank finance.

One form of contract is through one or more power purchase agreements (PPAs)[29]. Discussions with industry parties indicate that underwriting generation investments with PPAs is becoming more common, but some independent developers (those that don't have a load or retail base) still report that obtaining a PPA can be difficult. Several parties considered that

[29] A PPA involves the investor entering into an agreement with a party looking to purchase electricity (such as a retailer or industrial) that sets all the commercial terms for the sale of electricity between the two parties.

the prices offered by gentailers in PPAs were generally not attractive because gentailers weren't incentivised to provide good terms[30].

One party considered that historically there has been a lack of industrial power users entering into PPAs in New Zealand. The party thought this may be due to New Zealand industrials being less familiar with PPAs than their Australian counterparts and a smaller base of large industrials in New Zealand. However, the situation appears to be changing —some parties reported increased interest in PPAs by commercial and industrial parties. One party thought the corporate PPA market was about three years behind where Australia was.

Another party suggested the development of the PPA market would accelerate if the government (who is a large electricity user) used long-term PPAs to purchase electricity. This party considered that such a move could help underwrite new generation investment, bring downward pressure on electricity prices, and create more renewable energy. In addition, if the government did this in a very visible way, this could have wider demonstration benefits for other large power consumers considering PPAs.

Finally, there was a consensus among the industry parties we talked to that there was plenty of capital available for projects provided they had attractive cost structures and some forward revenue certainty. However, one party cautioned that the amount of capital available could reduce quickly up if the regulatory environment becomes more uncertain. This party emphasised the need for stable market rules and said that the Authority needed to communicate the importance of stability for long term investment decision making.

Cost pressure for generation equipment and civil contractors

Industry parties expressed a view that the cost of new supply for renewables (particularly wind and solar) has generally been falling over time but there was no consensus on whether this would continue. Some parties thought we had reached the bottom of the cost curves for wind and solar.

Some parties reported that there were upward cost pressures for civil construction—these included increasing commodity prices (particularly for steel with prices at an all-time high), labour shortages, global logistics and supply chain issues, and increasing health and safety costs. One party considered that global supply chain issues were expected to be transitory but could still last for 12-18 months.

Another party considered that there can be big shifts in costs depending on the state of international markets and thought that sometimes they needed to be patient and wait for the cycle to come around to a favourable position.

In general, cost pressures were not seen as an impediment for investment decisions but they could affect the prices at which developers were willing to forward contract.

[30] See comments in sections headed "Preference by vertically integrated parties to maintain balanced portfolios" and "Impact of portfolio effects on existing generation" on page 16.

Network capacity issues

Industry parties considered that in some areas of the country, investment in renewable generation was being constrained by network capacity issues. This was of particular concern in Northland. Several parties considered that Transpower should be able to take a longer-term view and build for the future rather than an approach which was oriented to immediate needs. This would require ‘overbuilding’ the grid in some areas particularly as we move towards having more intermittent renewable generation.

Some parties believed that the proposed Castle Hill wind farm (20km northeast of Masterton in the Wairarapa) had not been progressed because transmission connection was difficult and very costly. A party wondered whether it was worth the government setting up renewable zones (with ample transmission) to encourage the development of wind and solar generation.

Possible actions suggested by interviewees

Table 3 sets out changes that industry parties suggested could make conditions more conducive to investment.

Table 3: Changes that may make conditions more conducive to investment

Possible change	Key issues it may help address	Comment
1. Futures market changes, including longer-dated futures, peak products, better market making	• Future market signals • Need for revenue certainty	We understand some work is occurring in this area.
2. Streamlining the Resource Management Act (RMA) process	• Long development cycle	Streamlining the RMA process could allow investors to react more quickly to investment signals.
3. Better signalling and certainty around government policy (particularly around the NZ Battery Project and climate change)	• Future market signals	Policy uncertainty may deter some potential investors. Policy makers need to weigh this issue as they consider changes.
4. Government use of long-term PPAs to purchase electricity could underwrite new entry and create more renewable generation	• Need for revenue certainty	This could help develop a market for PPAs as has occurred in some other countries. This could strengthen competition.
5. Allowing/encouraging Transpower to overbuild the grid	• Lack of grid capacity	This may improve investment conditions in areas where wind and/or solar conditions are good for generating but currently lack grid capacity, but there is an unresolved question of how such costs would be recovered and whether this would lower overall costs.
6. Setting up renewable generation zones (with ample transmission)	• Lack of readiness • Long development cycle • Lack of grid capacity	See previous point.

Appendix 2 – list of industry parties interviewed

We interviewed staff from the following industry parties:

- Contact Energy
- Energy and Environment Ltd (advising certain industrial users on energy procurement project)
- Genesis Energy
- Lightyears Solar
- Lodestone Energy
- Mainpower NZ
- Mercury
- Meridian Energy
- Todd Energy/Nova Energy
- Tilt Renewables
- Top Energy
- Transpower
- Trustpower
- Ventus Energy.