concept consulting

Various analyses of current electricity and gas market dynamics

4 May 2025

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Executive summary

This note sets out analysis in four areas:

- electricity system balance – examining how we got to our current situation of scarcity, and future outlook
- gas market – outlining the gas information problems that exacerbated electricity scarcity, and future gas sector challenges
- electricity prices – examining how and why price outcomes differ between consumer segments
- energy scarcity-driven de-industrialisation – examining how and why some sectors have been impacted and consider the future outlook.

Electricity system balance

The electricity system balance is currently tight – that is, there is a structural shortfall in generation capability. The two key drivers of this are:

- *gas supply not meeting expectations*. Following an initial mid-2018 supply shock, the gas sector consistently projected that planned investment would restore surplus supply within two years. This dampened the signal to build renewables to displace thermal. In reality, drilling campaigns have delivered disappointing results and gas supply has continued to decline. Production in 2024 was 45% lower than projected just two years earlier
- *risk of Tiwai exit*. Until a new long-term contract was announced in mid-2024, there was a real risk the aluminium smelter at Tiwai would cease production from the end of 2024. This material downside risk (amounting to 13% of electricity demand) further dampened the signal to build new electricity supply.

With Tiwai uncertainty now resolved, and the market appearing to have settled on an expectation of gas scarcity continuing for the foreseeable future, a wave of new renewable projects are being developed.

Using our database of announced projects and developers' stated intentions for project timings, our modelling indicates electricity system balance will be substantially restored by 2028, and fully restored by 2030.

This is different to market expectations (represented by forward contract prices) which indicate a much smaller reduction in the scarcity situation by 2028. This difference may best be explained by the market as a whole having a less optimistic view than individual developers of the pace at which new generation will come online. This could, in turn, reflect views on the likelihood of resource consenting and grid connection delays.

Gas market

The current state of gas supply is largely due to 'bad luck' – ie, over $1.5bn of investment in development wells has almost universally delivered output below producers' mid-point expectations.

However, the impact of these disappointing results on the electricity market is significantly exacerbated by a lack of good information flow. In particular, although gas producers develop downside projections for internal use, they only publicly disclose mid-point projections.

Given there is a significant price asymmetry between gas over- and under-supply, this lack of information on downside risk will have materially reduced gas price expectations and suppressed the signal to invest in renewables to displace gas-fired generation.

This lack of public information on downside projections is further compounded by:

- projections being publicly disclosed half-a-year after they've been submitted by gas field operators
- projections only being produced once a year
- projections only covering annual quantities, rather than month-by-month production (for near-term)
- poor bilateral contract price disclosure and discovery – in stark contrast to the requirements for electricity contracts put in place by the Electricity Authority (and prior to that, the Electricity Commission).

Significantly improving the gas information environment is critical to enabling the energy sector to navigate as best it can through what is likely to be an extremely challenging future involving:

- ongoing gas declines in many of the fields.
- an 'integer' problem relating to the inability of the single remaining Methanex train to operate below a minimum stable operating level that is very large relative to the gas market. This creates significant challenges for on-selling Methanex's forward gas entitlements to higher value uses at times of relative scarcity (eg, during a dry winter)
- the high CO_2 content of some of the remaining gas reserves and resources (eg, at Kapuni and the Maui East accumulation), and the challenges of developing this gas without incurring high emissions costs.

One of the few bright spots in this otherwise challenging outlook is the potential for another underground gas storage facility to be developed at the Tariki gas field. Gas storage is likely to be increasingly valuable to address the challenges arising from declining gas field deliverability and flexibility, managing the Methanex 'integer' issue (and eventual Methanex exit), and increasing variability in gas demand as intermittent renewable generation increases.

Electricity prices

Analysis of public information reveals very different outcomes across three consumer segments:

- residential consumers have enjoyed real price reductions from 2015 through to the end of 2024
- the industrial food processing segment has also seen real price reductions from 2015 to 2023 (with no data yet published for 2024)
- the wood processing sector has seen significant real price increases (approximately 50%) over the same period.

This appears to reflect:

- *differences in hedging strategies*. Outcomes for residential and food processing segments are consistent with a strategy (by mass-market retailers and food processing companies) of maintaining a rolling three-to-four-year 'book' of hedge contracts. In contrast, outcomes for wood processing are consistent with greater reliance on spot purchasing and shorter-term forward contracts
- *additional factors constraining residential pricing*. Outcomes for residential pricing may additionally reflect downward movement in metering costs, retail cost-to-serve, or retail net margin. We do not have data to unpack the relative contributions of these factors, or how they compare to the contribution from multi-year hedging.

Although residential consumers have enjoyed real price reductions, the outlook for the next few years is for prices to increase due to:

- material increases in the lines component of tariffs
- high prices of recent years flowing into the 'rolling hedge books' used for residential consumers pricing.

Energy scarcity-driven de-industrialisation

Although overall industrial electricity demand has been in decline since 2005, analysis indicates this is principally due to the wood processing sector. All other industrial sectors have seen flat or growing demand over the same period.

Looking forward, analysis of electricity intensity and trade exposure data indicates that the worst of electricity price-driven de-industrialisation is likely to be over:

- the most vulnerable wood processing firms have already exited, while others are showing more resilience (eg, the re-opening last year of Pan Pac's Whirinaki mill following Cyclone Gabrielle)

- the only other two significant sectors that are both electricity intensive and trade exposed – aluminium and steel – have signed long-term supply contracts and, in the case of aluminium, are looking to expand.

There are still energy-driven de-industrialisation clouds on the horizon – but from gas scarcity, not electricity prices. Managing gas supply scarcity in a way that allocates gas to its highest value uses, with other users progressively switching to alternative fuels, will be a key challenge over the next five-to-ten years.

1 Introduction

This note sets out analysis in four areas:

- system balance – examines current structural shortfall in electricity generation capability, its drivers, and outlook for restoring balance
- gas market – recaps recent gas market issues, lessons from recent history, and near-term outlook
- prices – reviews how wholesale and end user pricing for different consumer segments has evolved
- de-industrialisation – reviews scope of past and future electricity price-driven reductions in industrial activity.

The analysis, undertaken by Simon Coates, was commissioned by Tony Baldwin to feed into his 'Independent Expert Panel' review on electricity market issues – noting that, due to potential perceptions of conflict of interest, Simon was not part of this Panel.

Although the Panel review was funded by Mercury – including funding for the analysis in this Concept paper – the Panel operated entirely independently from Mercury. As the Panel's report states *"Mercury has not exercised any control or material influence, nor implied any policy or commercial expectations, in relation to the group's work. The work has been undertaken at arms-length from Mercury".*

Furthermore, beyond specifying the issues they wished Simon to analyse, neither Tony nor Mercury provided any expectations to Simon as to the direction his analysis should take. Additionally, Simon had no involvement in any aspect of developing the Panel's recommendations, including any interpretation of his analysis.

2 Electricity system balance shortfall

Current and recent high prices have two key drivers:

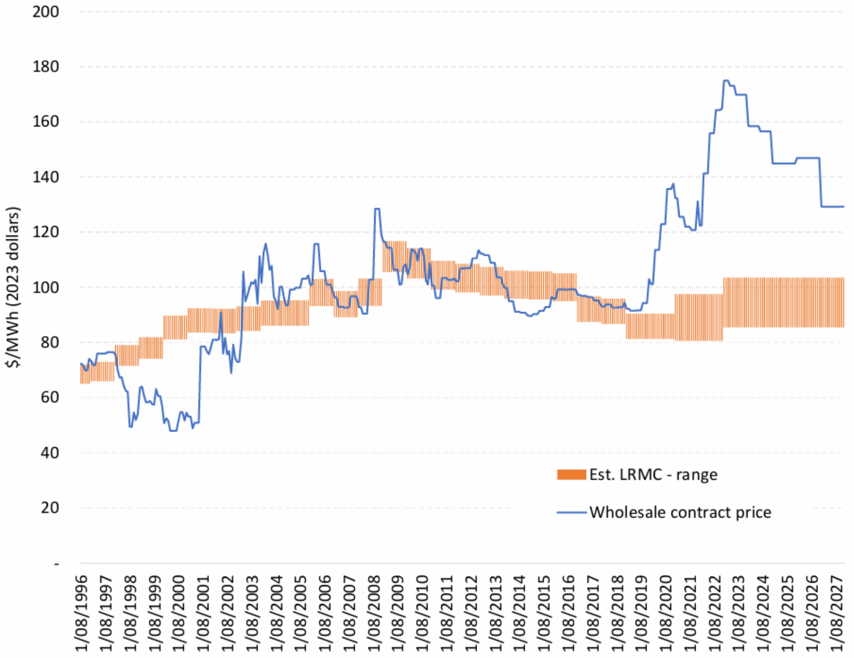
1. weather – low rainfall in hydro catchments means there has been a shortage of New Zealand's key renewable 'fuel'. This is a long-standing recurring feature of our hydro-based electricity system that will inevitably correct (or reverse) itself eventually when it rains
2. system balance – more fundamentally, there is currently a structural shortfall in electricity generation capability relative to demand. In this paper we refer to this as a 'system balance' shortfall.

A key indicator of the shortfall is the extent to which forward contract prices are above levels consistent with the long-run marginal cost (LRMC) of building new generation.[1]

This was illustrated in Figure 4 of the Electricity Authority's Level Playing Field options paper, repeated as Figure 1 below.

[1] LRMC is the cost of expanding supply to meet demand. This includes the levelised cost of energy (LCOE) for the lowest cost mix of new generation, plus the cost of 'firming' that new generation to match the within-day and through-year profile of demand.

Figure 1: Contract prices and estimated costs for new baseload supply



Source: Copied from https://www.ea.govt.nz/projects/all/energy-competition-task-force/consultation/level-playing-field-measures/

Forward contract prices for a year in advance are the best indicator of system balance, because their price is not influenced by current weather (or hydro storage) conditions.

These prices should represent likely spot price outcomes given the expected system balance, probability-weighted across the range of possible weather outcomes – eg, the chances of it being 'dry' versus 'wet'.

If the system balance is short, there is greater need to call on higher-priced supply sources – particularly when renewable generation is scarce during lulls in rain, wind or sunshine, or demand is high on cold days. Higher-priced supply sources include thermal generation (whose operating costs are much higher than renewable generation) and, at times of extreme scarcity, demand curtailment.

High contract prices are a signal to generators that it would be profitable to expand generation capability. Then, as new generation is progressively built in response to the price signal, the shortfall should progressively reduce until system balance is restored. At that time, contract prices should return to levels consistent with LRMC.

This dynamic of high contract prices incentivising generation investment is indeed what is starting to happen in New Zealand, with a large number of projects being progressed – albeit at various stages of development.

However, questions have been raised as to whether the pace of development has been fast enough, with prices having been high for around six years and with the ASX forward curve out to 2028 remaining stubbornly high. In this respect, it should be noted that the analysis in Figure 1 was undertaken in 2023. Since that time, if anything the separation between contract prices and LRMC has gotten worse, with forward contract prices being even higher relative to LRMC than was the case in 2023.

Against this background, this section of this paper presents analysis of:

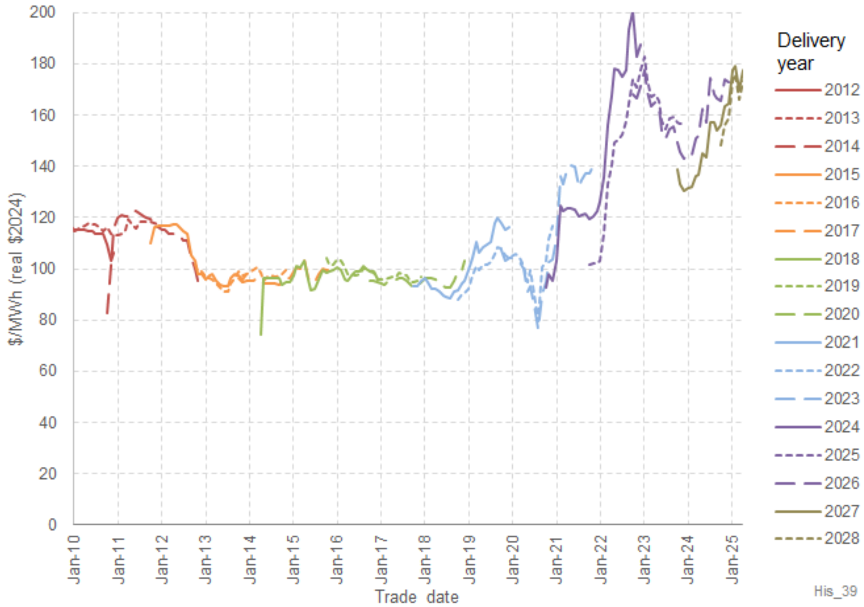
- potential causal factors for the current shortfall
- when the system is likely to return to a balanced position
- the level of investment that could (with perfect foresight) have prevented the shortfall and elevated prices experienced since late 2018
- the impact of uncertainty regarding the post-2024 future of the Tiwai aluminium smelter.

2.1 What caused the current shortfall?

Figure 2 indicates that New Zealand enjoyed a period of relatively stable contract prices, consistent with a balanced system, from the latter half of

2012 through to the first half of 2018.[2] At these prices, it would not have been profitable to build significant new renewable generation – ie, there was no need for new supply.

Figure 2: ASX Otahuhu forward contracts for calendar year strips (real $2024)

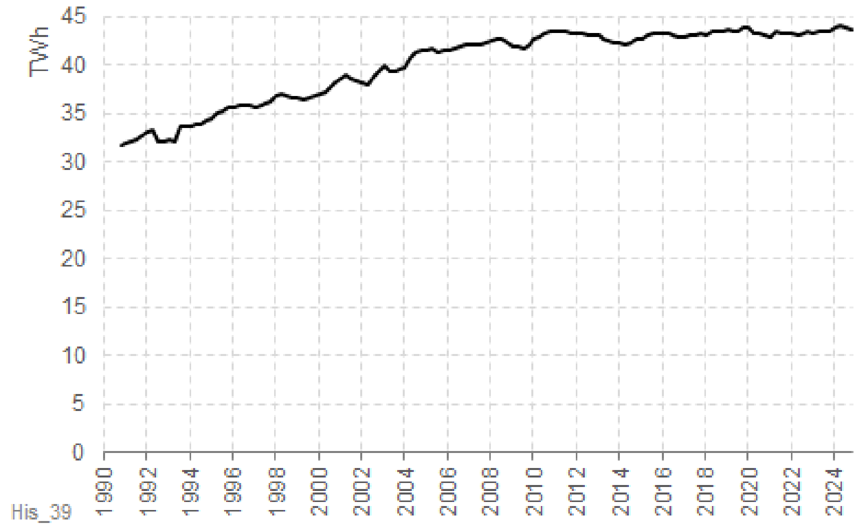


Source: Concept analysis of Electricity Authority data

What then caused the market to move into a disequilibrium state during the latter half of 2018, and why has it persisted?

Figure 3 indicates that it was not due to a rapid increase in demand, as there has been minimal demand growth since 2010.

Figure 3: Rolling four-quarters demand for generation (to Dec '24)

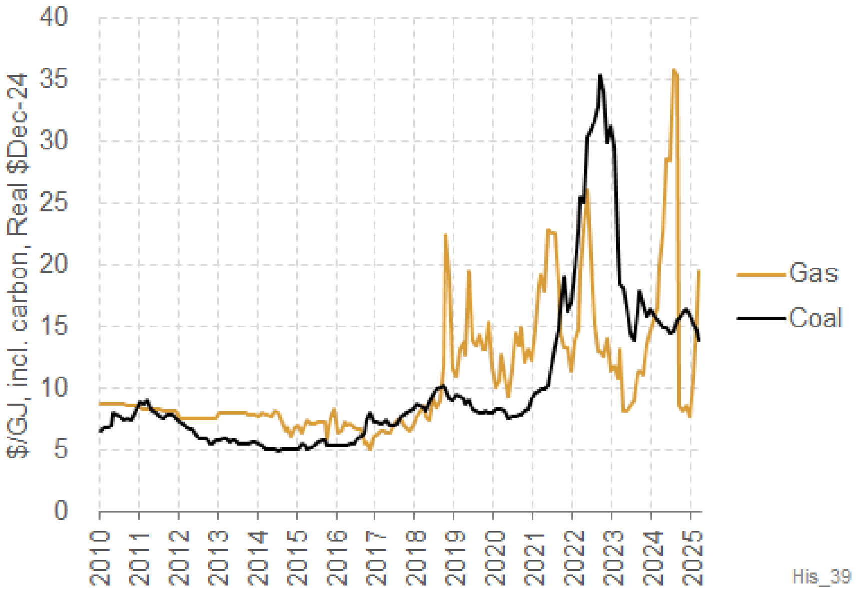


Source: MBIE data

Figure 4 indicates the principal driver of shortall was a sharp and sustained increase in fuel costs for New Zealand's thermal power stations from the latter half of 2018.

2 All prices in this paper are in real $2024 terms, with historical and forecast consumer price index (CPI) movements used to convert from nominal to real.

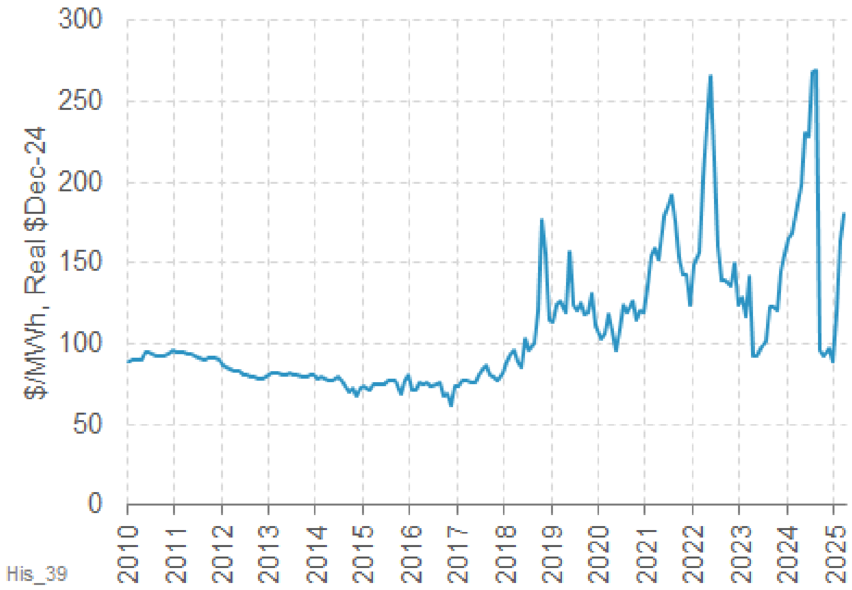
Figure 4: Monthly average gas and coal prices including carbon, Real $2024



Source: Concept analysis of EMS and IEA data

The broad effect on the cost of thermal power stations is illustrated in Figure 5, which shows a 'thermal SRMC index', being a simple weighted-average of the variable operating costs of thermal power stations.[3]

Figure 5: Thermal 'SRMC index', Real $2024



Source: Concept analysis of EMS and IEA data

The impact of this change in fuel cost is that:

1. prior to mid-2018 it was generally not profitable to build new renewable stations to displace thermal power stations

[3] We have applied constant weightings that broadly reflect how often each type of thermal stations is the marginal price-setter: CCGT = 10%, Rankine = 40%, OCGT = 50%. Clearly, the actual relative weightings vary over time, but the intention of this simple 'index' is to illustrate the general nature and scale of thermal cost increases.

2. since mid-2018 it has become profitable to build new renewable stations to displace most thermal (reducing system cost, and hence lowering electricity prices)[4]

This thermal displacement has started to happen – as detailed further in the next sub-section – but it is reasonable to ask why it didn't happen sooner.

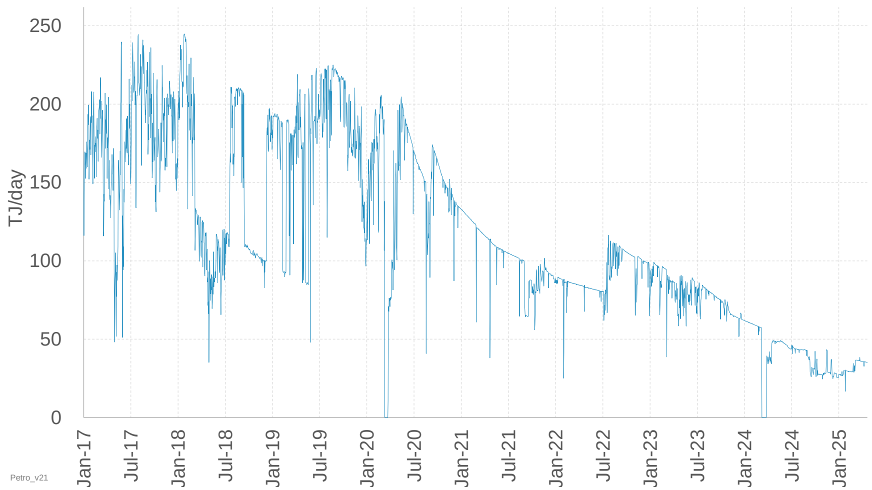
2.1.1 Gas supply has been persistently far less than projected

The initial explanation is that the rapid and sustained increase in gas prices from mid-2018 was unexpected.

The immediate cause of high gas prices in 2018 was the sudden failure in March 2018 of offshore wells for the Pohokura gas field – at the time, New Zealand's largest gas field, supplying approximately 38% of demand.

Figure 6, highlights the severity of the loss. For comparison, the loss was approximately equivalent (slightly larger) to a CCGT operating at full capacity.

Figure 6: Daily production from the Pohokura gas field

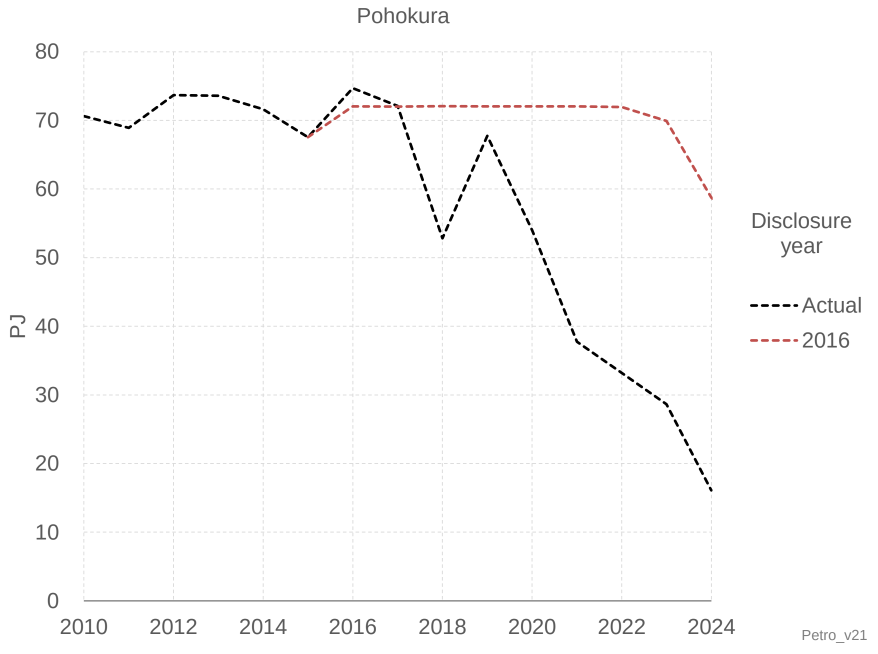


Source: GIC data

Figure 7 highlights that this loss was unexpected. It compares a publicly disclosed 2016 projection of annual production by OMV (the field operator) with actual annual production.

[4] The reasons it would not be cost-effective to displace all thermal power stations are explained in some detail in our October 2022 '*Which way is forward?*' report (specifically see pages 13 to 15) – available for download here: https://www.concept.co.nz/updates. In short, while it is cost effective to build renewables to displace thermals from high-capacity-factor flexibility duty (ie, plant that is on most of the time and turns down at times of surplus), it is progressively less cost-effective to displace thermals from low-capacity-factor flexibility duty (ie, plant that is off most of the time and only operates during acute scarcity). This is due to differences in relative cost-structures (renewables are high-capex-low-opex, while thermal is the reverse) plus renewables variability becomes increasingly difficult to manage if relied on for low-capacity-factor flexibility.

Figure 7: 2016 projection of expected Pohokura output versus actual



Source: Concept analysis of MBIE data

The out-of-the-blue nature of the production loss and resulting gas price spike in mid-2018 meant it was not possible to respond with new generation, noting it typically takes many years to develop and commission a power station. Engineering studies, planning, negotiating with landowners, consenting, building a grid connection, sourcing equipment and completing construction all take time – particularly for geothermal and wind projects which, at the time, were the only technologies that were cost-effective (because utility solar was still relatively expensive).

For wind, an additional challenge was that some of the sites that had consents from several years earlier were for turbine technologies that were no longer cost competitive. In simple terms, for a given potential wind farm site the consents acquired several years ago were for a larger number of smaller, less efficient turbines. In contrast, using the latest technology would result in a smaller number of larger but more efficient turbines. This change in technology meant that sites had to be re-consented.

This long lead time for developing new renewable projects goes some way to explain why, for the years immediately following mid-2018, the market was short of renewables.

However, another (arguably more significant) factor for the delay is persistent over-signalling (and under-delivery) of gas production.

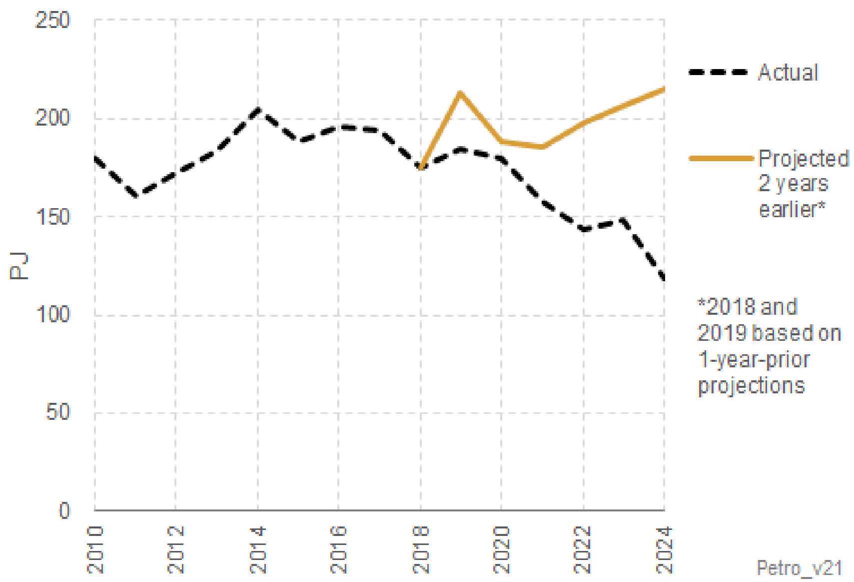
Following the failure at Pohokura, OMV indicated it was going to make a number of interventions to restore the field back to full production. Other operators signalled commitments to drill development wells at all of New Zealand's other main gas fields. In aggregate, upstream gas producers projected that gas production would return to, and even exceed, the previous high levels of production.

Over subsequent years, significant drilling activity did indeed take place – over $1.5 billion was invested from 2019 through to 2023 on development wells alone (ie, not including wells for exploring or appraising potential new fields).

Despite all this activity, Figure 8 shows that actual production was far less than projected. This was due to a combination of:

- drilling results being generally significantly worse than expected; and
- existing wells for many fields (particularly the offshore fields) declining – and in some cases failing – at a faster rate than expected

Figure 8: Projected versus actual whole-of-NZ gas production



Source: Concept analysis of MBIE data

The scale of shortfall was such that production in 2024 was 45% lower than projected at the start of 2022.

This situation, of persistently over-signalling and under-delivering gas production, will have materially dampened incentives to build new generation. Although short-term gas prices were high enough to justify new renewables, investors would have expected prices to ease back as gas production recovered to historical levels.

Importantly projections of gas supply provided by field operators were only on a P50 basis – ie, an equal probability that production would turn out higher or lower.

No projections were provided of the potential downsides to gas production – noting there is inherent uncertainty as to how much gas will be produced from a well once it is drilled, or how quickly its output will decline and eventually fail.

Because of these inherent uncertainties, it is standard practice for petroleum producers to prepare projections at different levels of probability – typically P10, P50, and P90 (known as 1P, 2P, and 3P) reflecting projections with a 10%, 50%, and 90% probability that gas production will be less than projected. However, gas producers are only required to provide 2P projections to the market at large through their annual disclosures to MBIE.

The lack of 1P projections in particular, meant energy market participants had no information regarding the downside risk for gas production.

Understanding downside (1P) projections is much more important than upside (3P). This is because there is a significant asymmetry:

- if there is a gas shortfall, prices rise steeply as supply moves up the cost curve, then steeper again if gas shortfall is particularly acute as demand rationing become necessary.
- in contrast, over-supply has relatively muted impacts. Methanex can generally absorb surpluses with little effect on price, and gas can be held in the ground one year for production the next – postponing the need for additional drilling.

If energy market participants had access to 1P and 3P projections, they would have had a better opportunity to develop a risk-weighted view of future gas prices, which would have provided a stronger signal to expand renewable generation.

Had new renewables been built just a couple of years earlier, it would have materially eased (although probably not completely eliminated) the extreme fuel scarcity experienced in Winter 2024 and is being experienced again this year – noting that pricing was driven in Winter 2024 (and again in 2025) at the extremely steep part of the cost-supply curve associated with demand rationing.

Section 3.2.1 sets out additional recommendations for improvements to gas disclosure requirements to improve this situation.

2.1.2 Tiwai posed a significant risk for renewable investment

Compounding the issue of gas production being materially lower than projected, there was also significant uncertainty regarding the future of the Tiwai aluminium smelter beyond its 2024 contract expiry. Had the smelter closed down, which its owners were indicating was a very real possibility, there would have been a 13% reduction in electricity demand – immediately pushing system balance into over-supply, with low prices and no need to build new generation. This risk would have significantly suppressed the incentive to build new generation.

This risk was removed in mid-2024 when the smelter signed a 20-year extension contract with no ability to exit within the first 10 years.

2.2 When will system rebalance?

After years of successive gas supply disappointments, the electricity sector now appears to accept that high gas prices are the new normal. Coupled with improved certainty regarding the Tiwai aluminium smelter, a wave of new generation developments are being actively progressed.

This sub-section considers how long it is likely to take to restore the electricity system to a balanced state, which should in turn see an end to elevated forward contract prices.

For this analysis, Concept has drawn on its database of potential new generation projects. This continuously-updated database records information about each generation project gleaned from developer announcements and other reports and studies.

Figure 9 and Figure 10 below show the 'pipeline' of projects in this database, differentiating by project development status and technology or developer.

Figure 9: Project pipeline by development status and technology

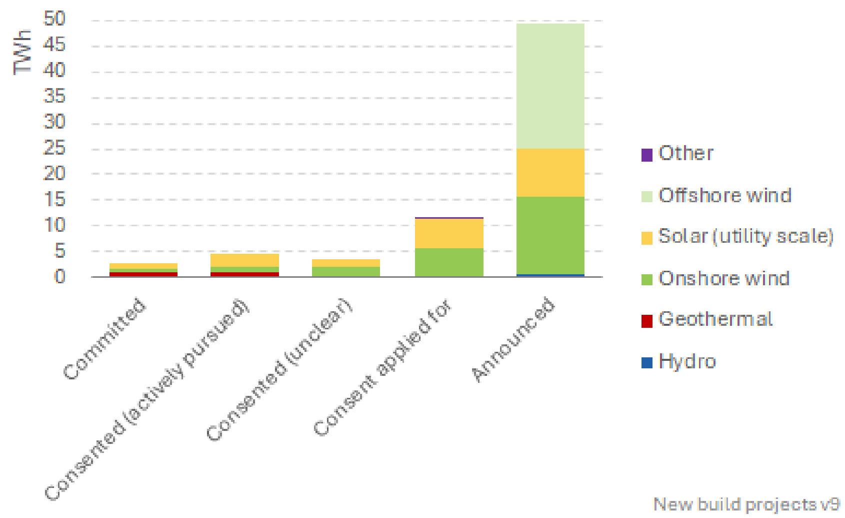


Figure 10: Project pipeline by development status and developer

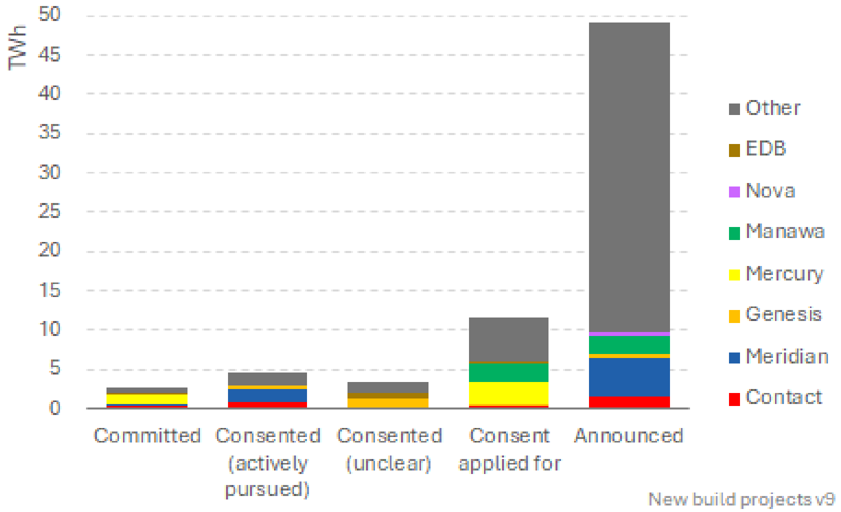
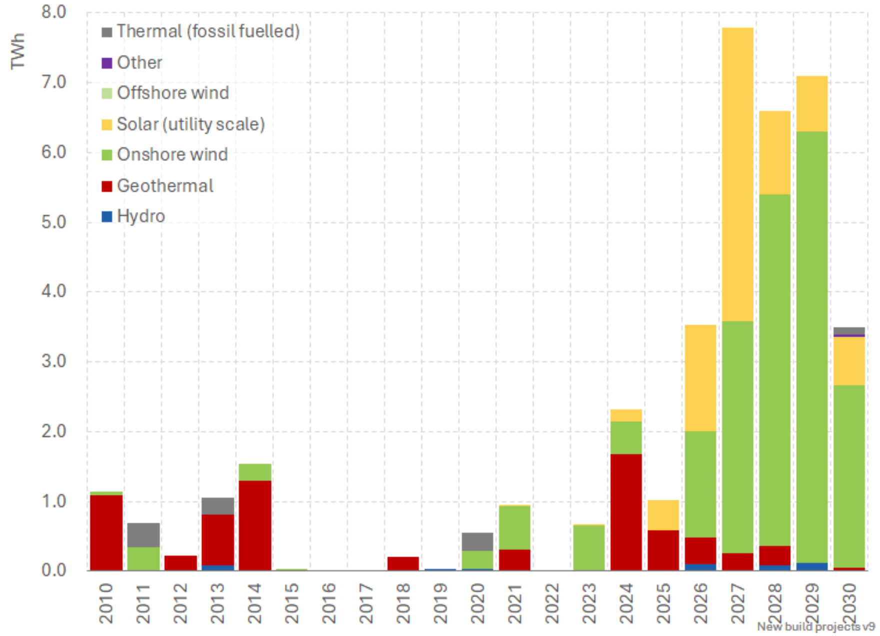


Figure 11: Projected GWh added if every generation project was built according to developer indications (up to 2024 = actual)



2.2.1 Indicated commissioning dates

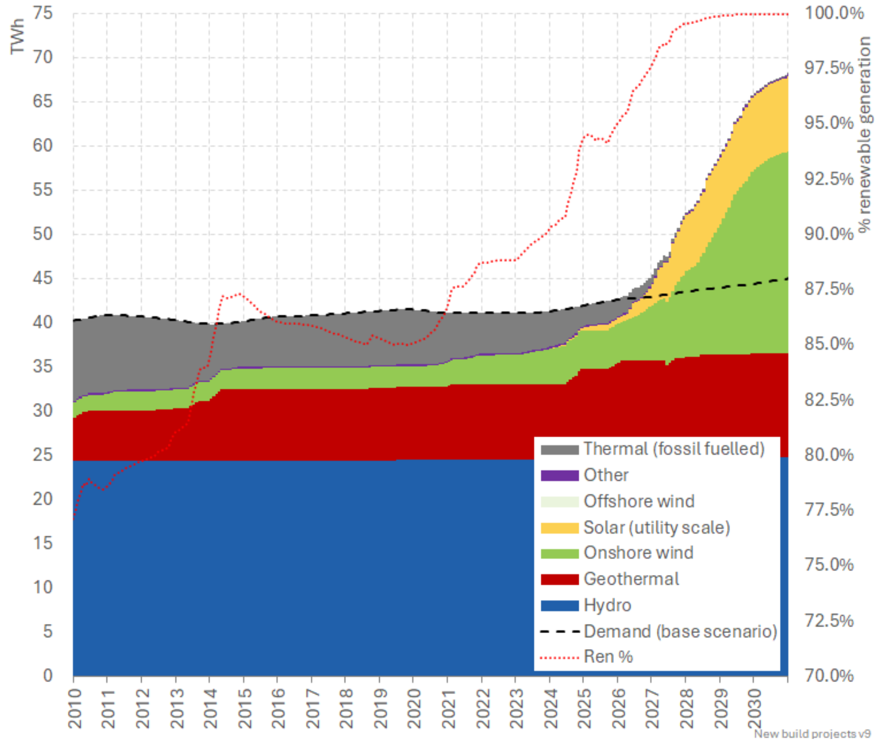
Figure 11 shows how much generation (expressed as GWh of energy per year) would be added to New Zealand's system if every project in our database were to proceed as per each developer's indicated commissioning date.

Figure 12 shows the resulting system balance outcome, assuming Concept's central demand growth projection of 0.75% per year from 2024 through to 2030, inclusive, based on our assessment of transport and process heat electrification over this period.

Additionally, the 'Ren %' line shows the percentage of generation that comes from renewable sources. This is the mean % generation, across all 'weather years'. (Ie, across the range of potential hydro, wind, and solar outcomes).

Note that the chart adjusts historical hydro and thermal generation to reflect mean hydrology, ensuring consistency between historical and projected system balance. The chart also excludes industrial cogeneration.

Figure 12: Projected system balance if every generation project was built according to developer indications (up to 2024 = actual)



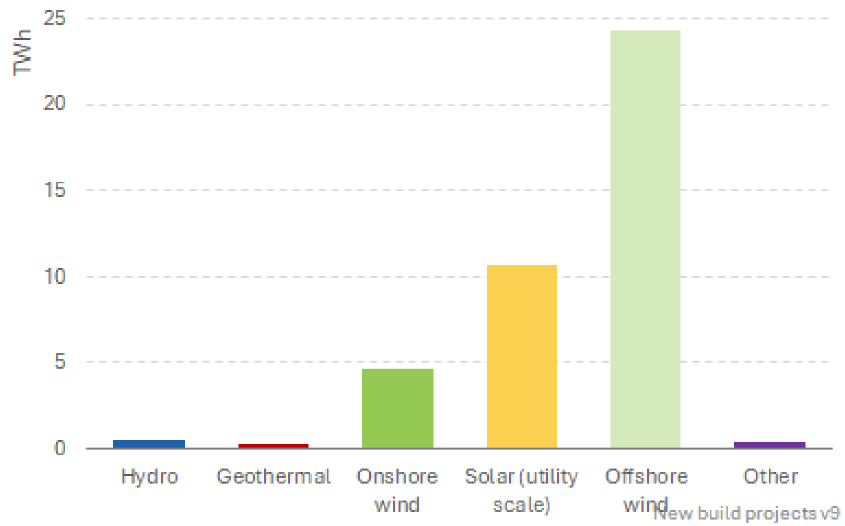
This projection indicates that, if all renewable projects were to be developed and commissioned at the dates indicated by the projects' developers:

- by 2028, thermal would be substantially displaced in a mean hydrology year (but would retain a significant role if 2028 were drier than average)
- beyond 2028, the system would move progressively toward a position of significant over-supply (unless demand growth picks up to an extreme extent, or developers significantly push back their plans).

The over-supply projected towards the end of this decade is clearly unrealistic. In this respect it is worth noting there are also *additional* projects for which developers have not indicated commissioning dates. These amount to a further 40.7 TWh per annum – ie, more than today's total demand and more than twice the amount of development shown in the earlier projection.

Figure 13 provides a breakdown of this additional potential supply by technology.

Figure 13: Additional announced projects for which no commissioning date has been announced



2.2.2 Realistic projection

To provide a more realistic projection, we have applied weightings to developments depending on their status, which we categorise as:

- commissioned – ie, already built

- committed – ie, under construction or passed FID[5]
- consented (actively pursued)[6]
- consent applied for
- announced – ie, a prospective project has been announced by the developer, but it hasn't reached the stage of applying for consents.

In our base scenario, projects that are committed are assumed to be 100% likely to go ahead, with no delay relative to the developer's announced timing.

For other project statuses, we apply the, by assumption, uncertainty de-rating factors shown in Table 1.

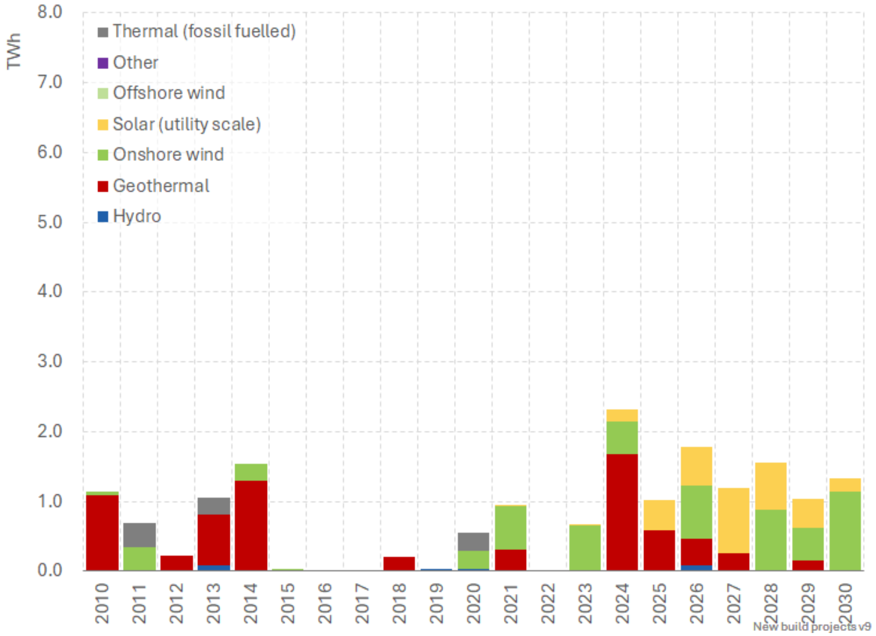
Table 1: Factors applied to projected projects in Base scenario

	Committed	Consented (actively pursued)	Consented (unclear)	Consent applied for	Announced
Prop'n proceeding	100%	64%	40%	22%	12%
Avg delay (mths)	0.0	7.9	11.9	20.0	21.3

New build projects v9

The resulting build schedule is shown in Figure 14 on the same scale as Figure 11, then in Figure 15 with a smaller vertical axis (which we then use for all subsequent graphs).

Figure 14: Base scenario of new generation developments (up to 2024 = actual)



5 FID = Final Investment Decision, after which the project will move to the construction phase.

6 This excludes consented projects where the developer has not indicated a likely completion date, as these projects are likely to be treated as future options, rather than actively pursued projects.

Figure 15: Base scenario of new renewable generation developments – smaller vertical axis scale (up to 2024 = actual)

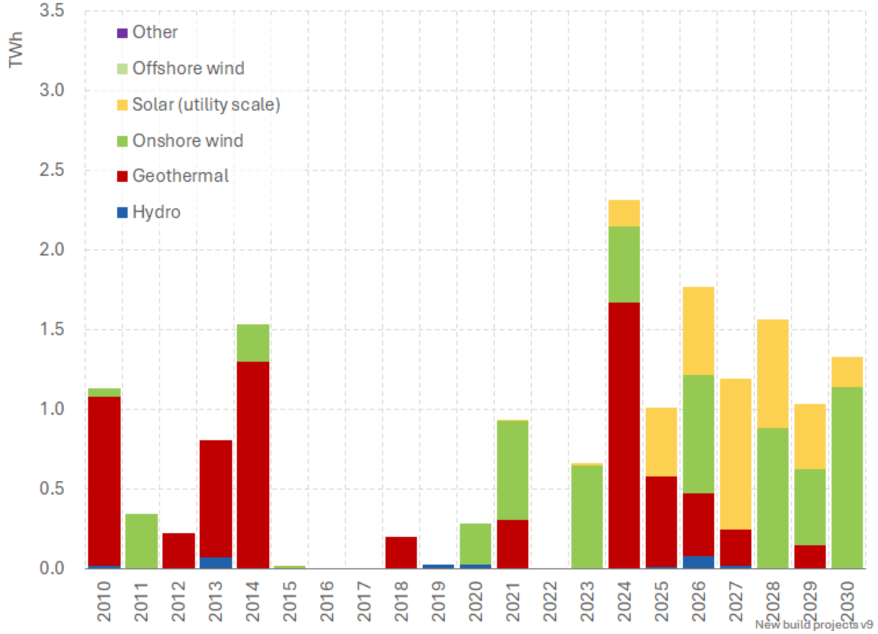
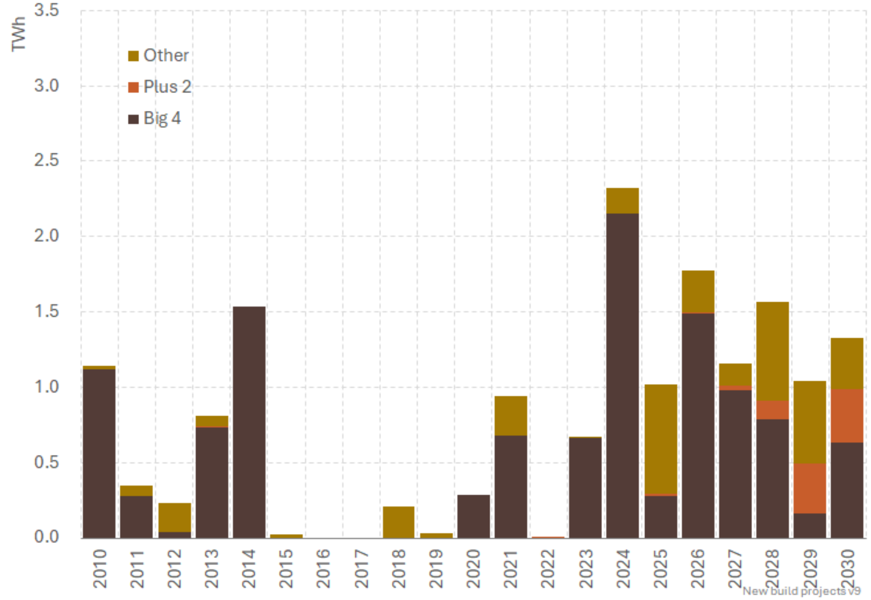


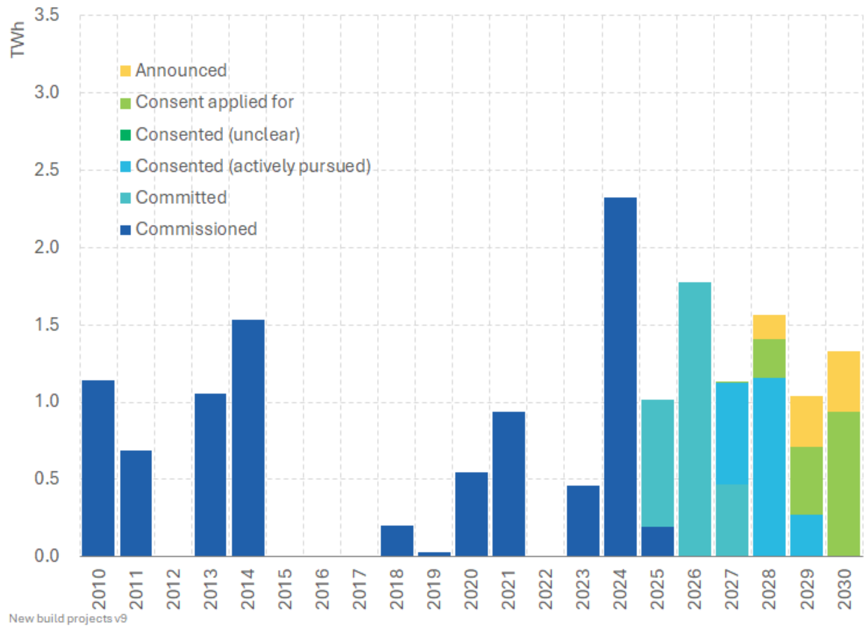
Figure 16 shows breaks down this historical and projected build by develop type – separating out the 'Big 4' gentailers (Contact, Meridian, Mercury, and Genesis), the 'Plus 2' gentailers (Manawa and Nova), and all 'Other' developers.

Figure 16: Base scenario of new renewable generation developments by developer type (up to 2024 = actual)



To provide further insight as to the likelihood of the projects being developed, Figure 17 breaks projects down by development status.

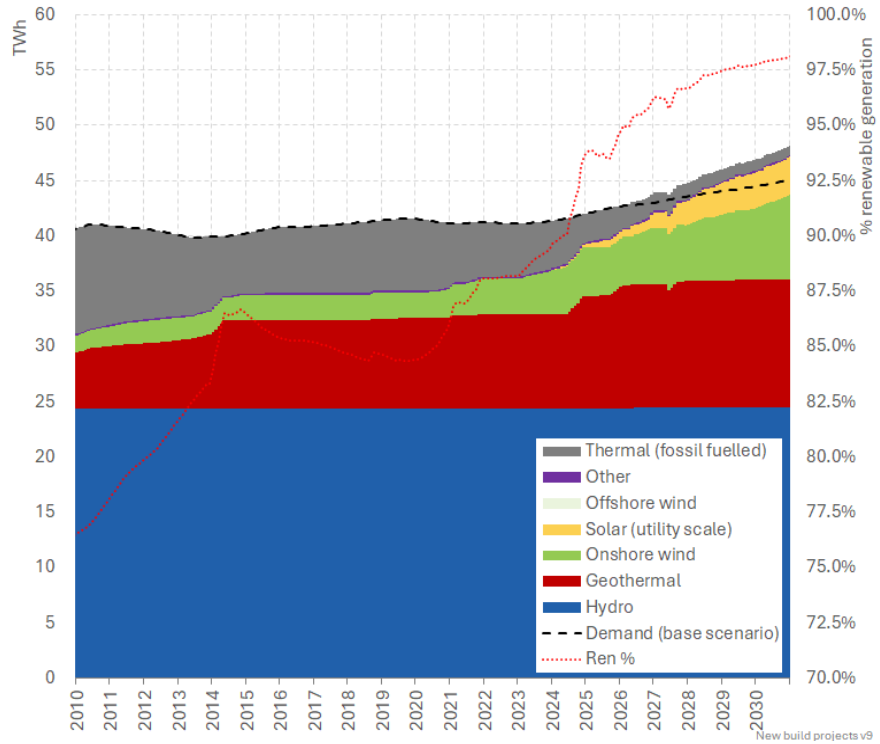
Figure 17: Base scenario of new generation developments by development status (up to 2024 = actual)



A significant proportion of the projected projects out to 2028 have a high-confidence development status – ie, 'committed' or 'consented (actively pursued)'. We have applied relatively conservative assumptions regarding the proportion of projects developed and their timing.

Figure 18 shows the projected system balance adopting the more realistic weighted developments from our base scenario.

Figure 18: Base projected system balance (up to 2024 = actual)



For latter years, the projected balance shows a cumulative total of renewable generation above the demand line, plus retention of some thermal generation. This reflects that:

- projections are on the basis of a mean 'weather year' – with mean rainfall, wind, sunshine and temperature
- at times (even within a mean year) there will be renewable 'spill' – eg, when it is warm and sunny, lakes are high, and the wind is blowing
- at other times, thermal will be required to firm supply – eg, when lulls in wind and sunshine coincide with low lakes and low temperatures.

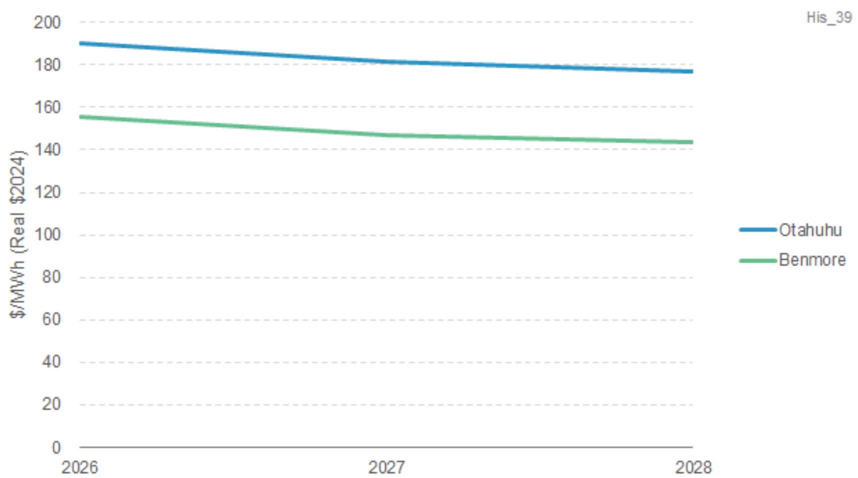
We combined the projections from Figure 18 with modelling from our most recent quarterly price forecasting to assess how quickly the system moves back into balance.[7]

This indicates that:

1. the system will be in balance by mid-2030, with contract prices returning to LRMC-driven levels
2. by mid-2028, the market will be close to balanced, with prices no longer significantly elevated above LRMC values.

This differs from the current ASX forward curve (shown in Figure 19),which indicates an expectation of shortfall persisting into 2028 – albeit with some relaxation compared to 2025.[8]

Figure 19: ASX hedge prices for calendar years 2026 to 2028, traded on 25 April 2025



This divergence between modelled and traded prices in 2028 could reflect a range of factors. Beyond caution and pessimism provoked by recent history, this could include market expectations of:

- greater delays to new generation – potentially due to delays in getting a grid connection or getting a consent
- more rapid demand growth
- higher thermal fuel prices.

In our price forecasting, we have assessed the sensitivity of outcomes to these factors and, while they could explain some of the difference (particularly from delays in new generation), we still come to the conclusion that ASX prices for the outer years appear elevated beyond our assessment of market fundamentals. It is beyond the scope of this study to examine this issue in more detail.

2.3 What could have been built to prevent shortfall?

As set out in 2.1, two significant reasons for the current system balance shortfall are:

1. gas supply expectations – the mid-2018 supply shock was unanticipated, and producers subsequently over-signalled how quickly gas supply would be restored. The expectation of a return to lower gas prices dampened the signal to build renewables to displace thermal
2. Tiwai exit – until a new long-term contract was announced in mid-2024, there was a risk the aluminium smelter at Tiwai would cease production from the end of 2024. This material downside risk

7 We updated our price forecasts quarterly and they are available for one-off purchase or on a subscription basis.

8 Our modelling projects 2025 prices that are only slightly lower than ASX prices.

(amounting to 13% of electricity demand) further dampened the signal to build new supply.

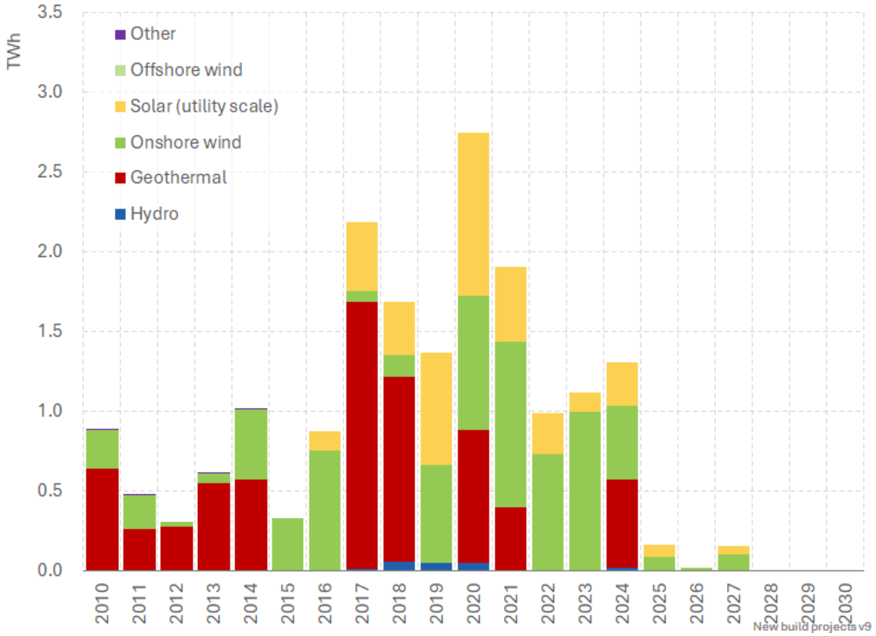
We have assessed what would "should" have been built if developers had perfect foresight that gas prices step up and stay high from mid-2018 and that the smelter would commit to operating beyond 2024.

To do this, we brought forward by 'x' years all projects developed after month 'y', and varied x and y until a balanced solution was found. This is a relatively simple approach that provides a reasonable first-order approximation up until the mid-2020s.[9]

The resulting parameters were to bring forward by seven-and-a-half years any projects commissioned from November 21 in our base scenario.

Figure 20 shows this "perfect foresight" build schedule, and Figure 21 shows the resulting system balance.

Figure 20: Renewable build schedule required to deliver a balanced market given perfect foresight of gas prices and Tiwai's decisions



[9] A more sophisticated optimisation, which would alter outcomes in later years, is beyond the scope of this paper.

Figure 21: System balance with perfect foresight regarding gas supply and Tiwai production

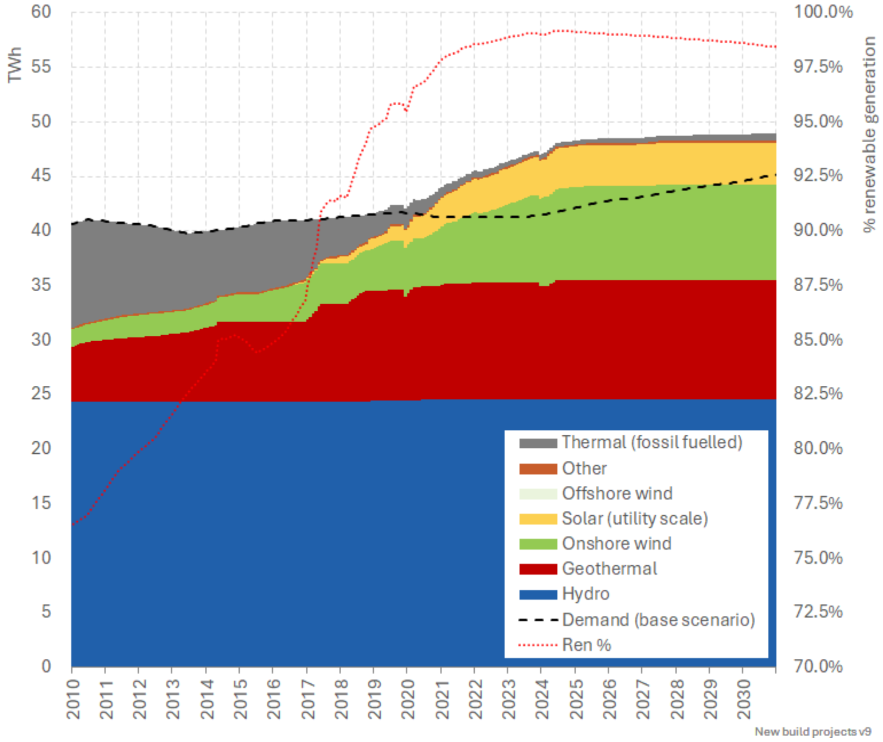
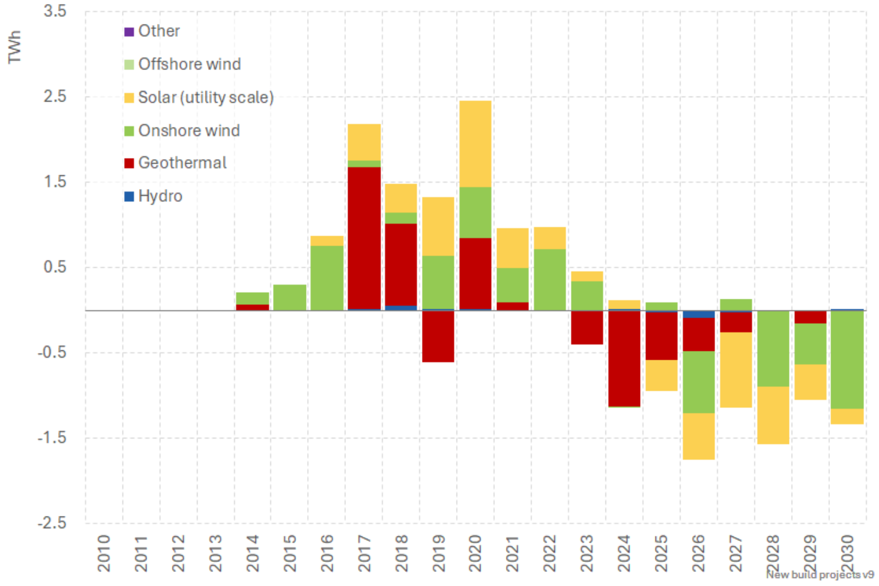


Figure 22 below shows the difference in build schedules between the two scenarios – ie, the difference between Figure 20 and Figure 15.

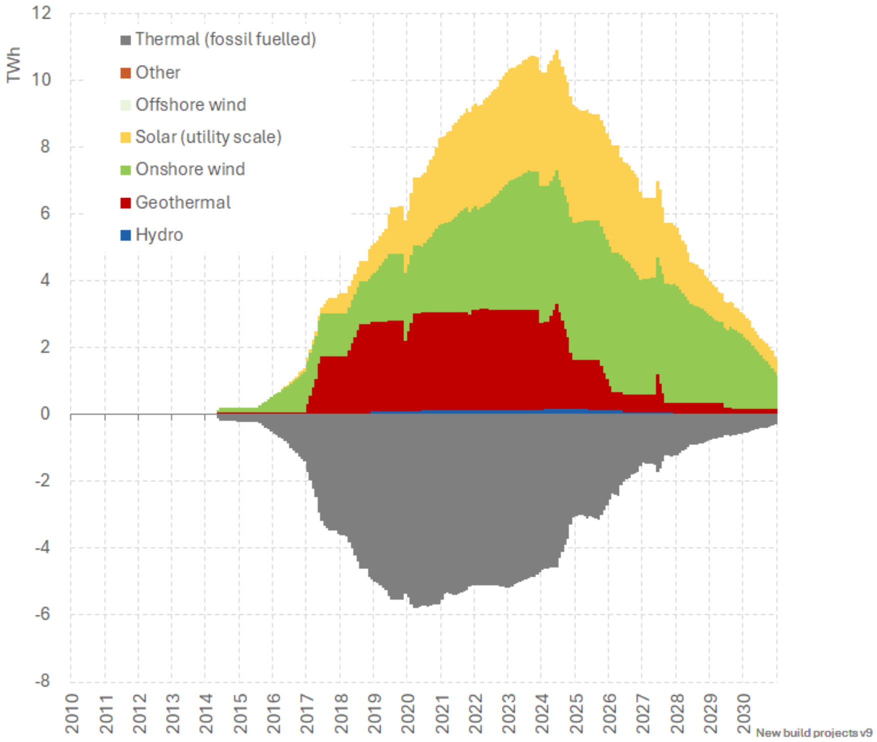
Figure 22: Difference in build schedules between perfect foresight and base scenarios



This shows the significant increase in build that would have been required throughout the middle of the last decade. Given the lead times for development, including engineering studies, consenting applications, and the like, this would have required efforts gearing up from 2012 or earlier.

Figure 23 shows the difference in generation outcomes between the perfect foresight and the base scenarios. Unsurprisingly, the perfect foresight world would have required far less thermal generation.

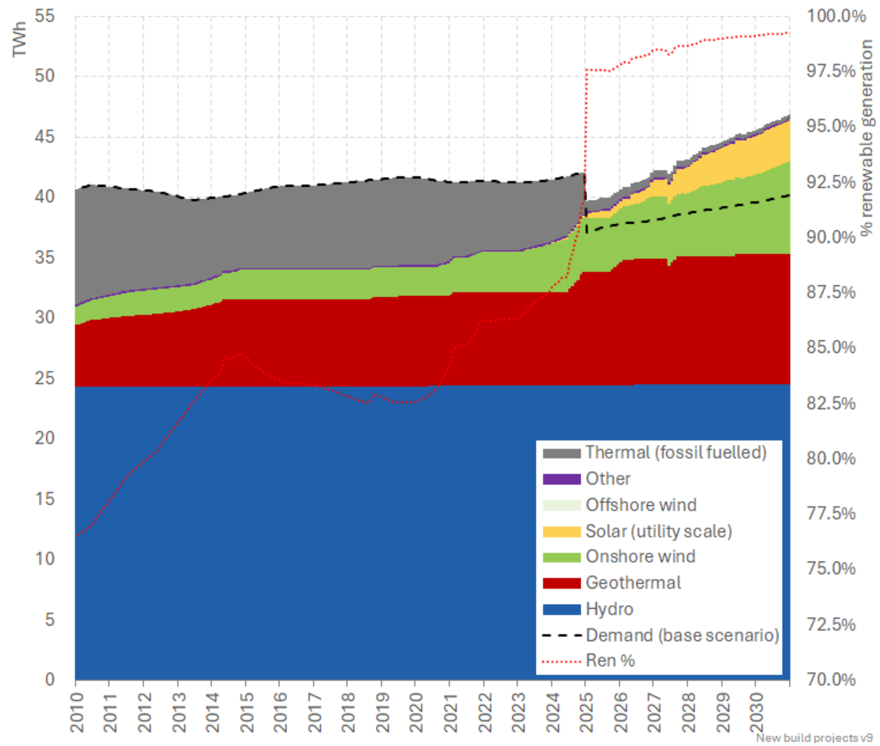
Figure 23: Difference in generation outcomes between perfect foresight and base scenarios[10]



2.4 How significant was Tiwai uncertainty?

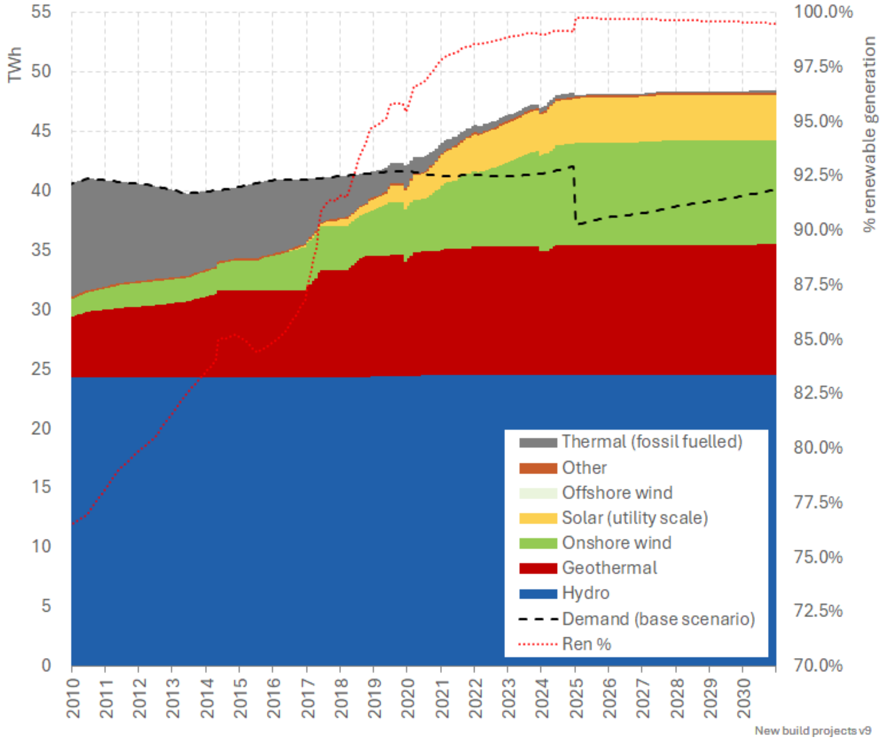
To illustrate the destabilising effect of uncertainty around Tiwai's prospects, the following two charts show the system balance outcomes for both the base and perfect-foresight scenarios, but with Tiwai exiting at the end of 2024.

Figure 24: System balance outcomes for base scenario if Tiwai exited at end of 2024



10 Note that increased renewable isn't an exact mirror of reduced thermal because a portion of the renewable production would be spilled.

__Figure 25: System balance outcomes for perfect foresight scenario Tiwai exited at end of 2024__



The two figures illustrate how the system would have lurched into over-supply from 2025 onwards. The associated low prices would materially harm the profitability of projects built in preceding years – especially in the perfect foresight scenario.

With respect to the Base scenario, had Tiwai exited at the end of 2024, almost none of the projects projected to be built from 2025 through to mid-2029 would be required to bring the system into balance. Were they to still to proceed after a Tiwai exit, they would push the system into a surplus situation, with the resulting low prices making the investments unprofitable.

3 Update on gas market issues

As set out in section 2.1, the current tightness in the electricity system is in large part due to problems in the gas sector. This section of the report:

- recaps gas market issues experienced over the past decade, with a focus on the most recent years
- draws out some lessons from this experience
- provides a high-level evaluation of the future outlook for the gas sector.

3.1 Recap on past decade

After almost a decade of relatively balanced gas supply, in March 2018 an unexpected large-scale loss of supply from the Pohokura gas field (then New Zealand's largest field) caused the price of gas to rise significantly. In turn, this caused the cost of thermal generation to almost double.

For the following five years, the gas sector consistently indicated that planned drilling campaigns would restore gas production to past levels. This in turn would be expected to return gas prices to levels consistent with a balanced gas market. This expectation significantly suppressed the price signal to build renewables to displace thermal generation.

However, despite investing $1.5 bn drilling development wells, results were significantly below expectations across all six of New Zealand's main fields. In addition, several fields experienced rates of decline and well-failure that were faster than expected. Accordingly, rather than returning to balance, gas scarcity progressively worsened.

Declining gas deliverability was significantly masked in 2022 and 2023 because they were relatively wet years[11], reducing the need for gas-fired thermal generation and resulting in relatively subdued electricity spot prices. While this may have provided some short-term relief from the gas scarcity situation, it may also have weakened the impetus for larger electricity and gas consumers (and some retailers) to hedge forward. It may also have further suppressed the price signal to develop additional renewable generation.

However, 2024 turned out to be very dry – particularly in the critical winter quarters when electricity demand is highest. The third quarter was extremely dry, with hydro generation being the second lowest over the past thirty-two years. The resulting demand for thermal generation then brought gas market scarcity to light with:

- gas and electricity prices rising to extreme levels (as illustrated Figure 27 on page 28 later)
- very large volumes of coal burned at the Huntly power station
- some curtailment of electricity and gas demand, particularly from industrial consumers
- potentially, some permanent demand reductions. In particular, Methanex permanently idled two of its three methanol production trains[12] and some wood processing sites closed citing energy prices as a contributing factor.

Although Methanex idled one of its Motunui trains in March 2024, it kept the other train operating for most of the winter, even though the price of gas was substantially above the likely net-back it could receive from using the gas to produce methanol. At the same time, as illustrated in Figure 26, New Zealand was consuming large amounts of coal to power the Huntly thermal generator (effectively, New Zealand was making methanol out of coal).

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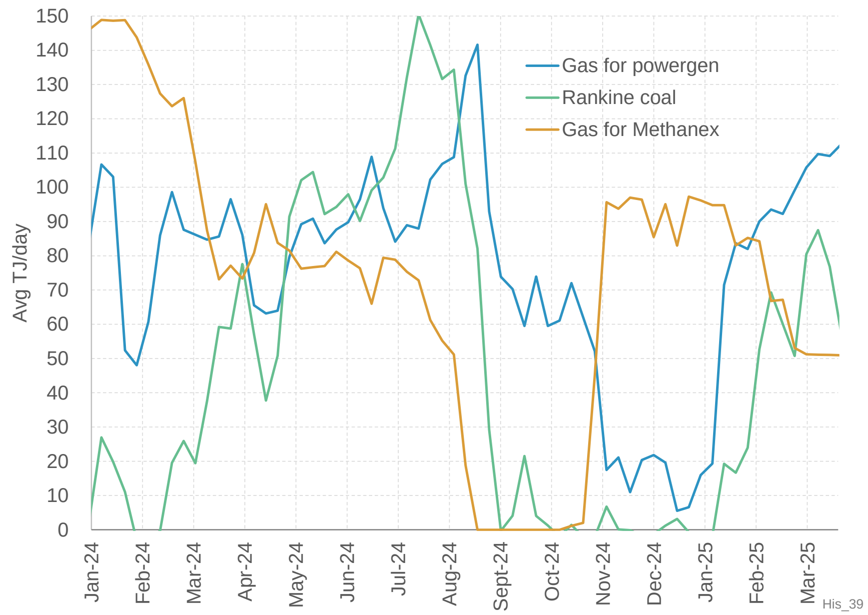
11 2023 and 2022 were the second and third highest years, respectively, in terms of hydro generation over the past twenty-five years.

12 The Waitara Valley train had already been idled in 2021, and one of its Motunui trains was idled in March 2024. Methanex subsequently indicated that these are likely to be permanently retired.

Figure 26: Weekly fuel consumption



Source: Concept analysis of GIC and Electricity Authority data

Eventually, however, Methanex did agree to on-sell its remaining gas entitlements to the two main gas-fired generators, Genesis and Contact, and idled its remaining train for the period from mid-August to the end of October.

This gas reallocation significantly alleviated electricity market scarcity. Soon after, the market lurched into significant surplus, with gas and electricity prices collapsing to close to zero, because:

- toward the end of July, Meridian exercised its contractual option to call on demand response from the Tiwai aluminium smelter, and subsequently
- heavy rainfall started refilling hydro reservoirs, displacing the need for thermal generation.

It appears that history has been repeating itself in 2025 with another extremely dry inflow situation, high coal use for electricity generation, high gas and electricity prices and, despite this, Methanex only reducing consumption to approximately 51 TJ/day.

It is not clear why, since economic fundamentals would strongly support reallocation of gas from methanol to electricity, Methanex has not struck a deal to on-sell its gas to electricity generators.

3.2 Lessons from recent history

3.2.1 There is an information problem

Greater transparency of gas production and contract pricing information would enable energy users, including the electricity generators and users, to improve their decision-making.

Gas producers are required to submit information to MBIE at the beginning of each year detailing their estimates of:

- reserves and contingent resources within each of their fields[13]
- projected production profiles for the reserves.

13 Reserves are accumulations of gas where the gas producer has already made, or has committed to make, the investment in development wells to extract the gas. Contingent Resources are gas accumulations where the gas field operator has expectations of the gas being there (to varying degrees of probability) but where it hasn't yet made any commitment to undertake the investment (and may never make such an investment) to develop the gas.

While the information that MBIE subsequently publishes is useful, it is arguably inadequate to support efficient decision making by parties impacted by gas supplies. Key issues are:

- delay – the information, which MBIE receives early in the year, is not published until the second half of the year
- frequency – annual updates are too infrequent at times of market stress. A quarterly cycle would significantly enhance information value. We understand at least some operators produce updated projections more frequently for their own purposes, so the incremental cost of disclosing quarterly should be significantly outweighed by improvements in downstream decision making
- risk profile – disclosures only cover expected (2P) production. As set out in section 2.1, information on downside risk (1P production) would provide energy market participants with richer understanding of production risk. We understand operators already produce such profiles for internal use and, in some cases, share this information with their largest customers under the terms of their sales agreements
- within-year profile – disclosed profiles only cover annual production amounts. At times of market stress, it would be helpful for energy users to see monthly profiles, which would help assess crucial winter risk. Again, we understand operators produce monthly profiles (at least for the first few years) for internal purposes.

Information on gas contract prices is even less transparent. Coupled with a relatively concentrated gas market, the lack of transparency can lead to outcomes that excessively favour suppliers over consumers.

In contrast, the electricity sector regulator (the Electricity Authority now and the Electricity Commission previously) has introduced, refined and extended contract price disclosure requirements over time to ensure much superior price transparency for electricity contracts.

It is not clear there is a compelling reason that gas contract pricing should be so much more opaque than electricity.

3.2.2 Methanex now presents an ‘integer’ problem

Historically, Methanex has provided an enormously valuable source of flexibility to the gas and electricity markets, with significant ability to increase or decrease its Methanol production to help balance the system. At times of relative scarcity, Methanex has traditionally on-sold some of its gas entitlement to other consumers such as gas-fired generators (whose usage is more valuable but less steady).

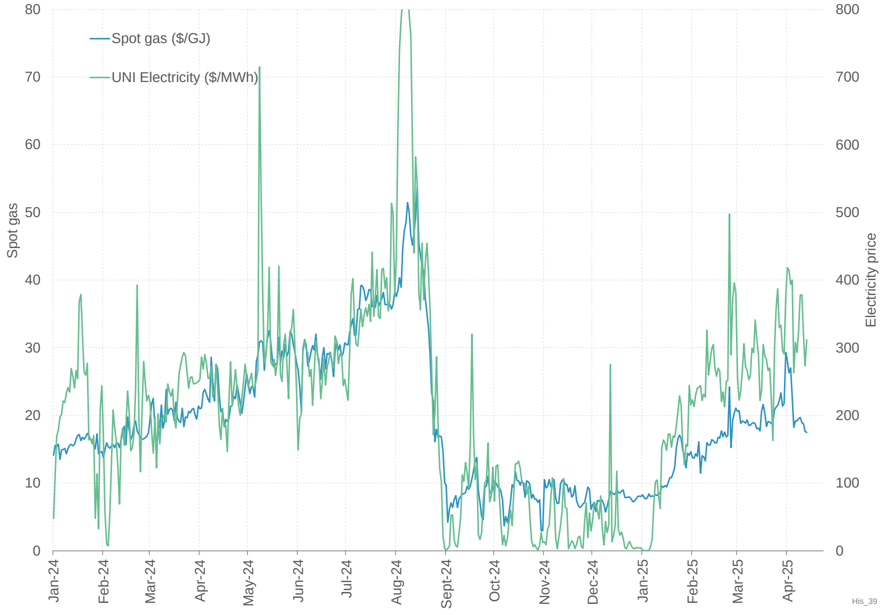
However, methanol production is not infinitely flexible, and each train has technical constraints on its minimum operating levels. Until recently, the per-train limit has not been an issue, as Methanex has been able to balance production across multiple trains.

However, for last winter and this one, Methanex has been down to a single train and its minimum operating level presents a ‘block’ on its ability to ramp down production and on-sell gas. To do so, Methanex needs to cease production and on-sell its full volume. This is worthwhile when there is extreme scarcity, but not for less acute situations.

This effect is apparent in Figure 26, where in the early part of 2025:

- electricity supply was stressed, as indicated by coal and gas usage for power generation
- Methanex curtailed its consumption through the early part of this year, freeing up gas for generation, but reached a floor of around 51 TJ/day
- methanol usage then stays at the floor, despite gas and electricity prices remaining at significantly elevated levels (and coal consumption remaining high).

Figure 27: Daily average gas and electricity prices (Real $2024)



Source: Concept analysis of Electricity Authority and EMS data

Were Methanex to on-sell more gas to the generation market, it would likely:

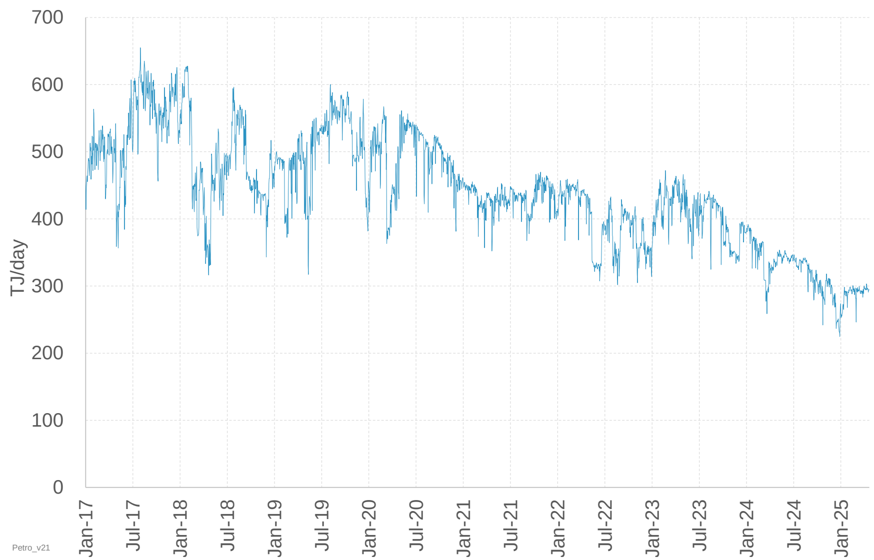
- materially reduce spot gas and electricity prices, and
- significantly reduce the amount of coal burned in the Huntly power station.

The challenges around methanol minimum volumes have parallels with the issues discussed earlier regarding Tiwai uncertainty. In both cases, markets find it difficult to deal with large step-changes in supply and demand – that is, with 'integer' problems. These are an inherent challenge for our relatively small and unconnected energy system. Transparent information is particularly valuable for planning around step-change uncertainties.

3.3 Future outlook

Figure 28 shows that, after two years of steady decline, total gas production appears to have stabilised at around 300 TJ/day from the first quarter of this year. This is largely due to recent drilling at the Turangi and Pohokura fields bringing on new gas.

Figure 28: Total NZ daily gas production



Source: Concept analysis of GIC, MBIE, and Electricity Authority data

While stability is welcome, overall gas supply in New Zealand less than half its 2017 level.

Also, we understand production from the Pohokura 5 well that came online last month is well below expectations, and production from all three of New Zealand's offshore fields (Maui, Pohokura, and Kupe) is declining more rapidly their operators projected at the start of last year.

Currently no more drilling is committed for these offshore fields – almost certainly permanently so in Kupe's case. Whether further drilling happens for Pohokura and Maui will likely be tied to Methanex's future – in particular, because Methanex is the only party able to take the high-CO_2 gas that comprises the majority of the additional resources that could be developed at the Maui field.

The poor recent drilling results at these fields and accelerated declines will tend to act against OMV (the field's operator and majority owner) committing significant new capital in expensive offshore drilling campaigns. Additionally, uncertainty over the future of Methanex (as detailed further below) and regulatory uncertainty will also weigh against significant future capital investments in these offshore fields.[14]

Offsetting these negatives, elevated gas prices would improve expected returns were future drilling to be successful.

From a gas supply perspective, there are two relatively bright spots in an otherwise gloomy situation:

- Greymouth Petroleum appears to be having success in its drilling campaigns at its onshore fields, with deliverability picking up from the start of this year. We do not know whether the improvement from these wells is better than Greymouth had expected
- NZEC has had success drilling the onshore Tariki field. Although the increase in production is modest compared to the overall gas market, the field has potential to be developed into a gas storage facility larger than the current (and only) facility at Ahuroa. If this were developed, it could prove enormously valuable in providing the fuel flexibility needed to balance increased renewable generation – particularly if (or when) the remaining Methanex train finally exits.

Additional drilling is underway at Mangahewa, with four wells scheduled to come on stream progressively through the year. Depending on the success of these wells, it is likely further drilling will happen progressively over subsequent years.

No drilling is currently committed for Kapuni. Its high CO_2 content and poor results from the most recent drilling campaign make for a challenging investment decision by Todd, the field's owner-operator.

For Methanex, its long-term future in New Zealand looks uncertain. It has contracted forward for significant quantities of gas out to 2029. However, unless there is a significant new gas field discovered and developed within that time (which seems unlikely), it seems unlikely it would be able to re-contract for 2030 and beyond at prices that would be low enough to support profitable methanol production.

If gas deliverability continues to decline, it may even be economic to idle its remaining train earlier than 2029 – on the basis that other users with higher-value uses could consume all of New Zealand's production. This would create a challenging market dynamic as pressure builds to permanently reallocate gas to its highest value uses.

14 Regulatory uncertainty relates to possible future governments making policy changes to issues such as field decommissioning liabilities, free NZU allocation to Methanex, and restoring the recently-repealed ban on offshore exploration.

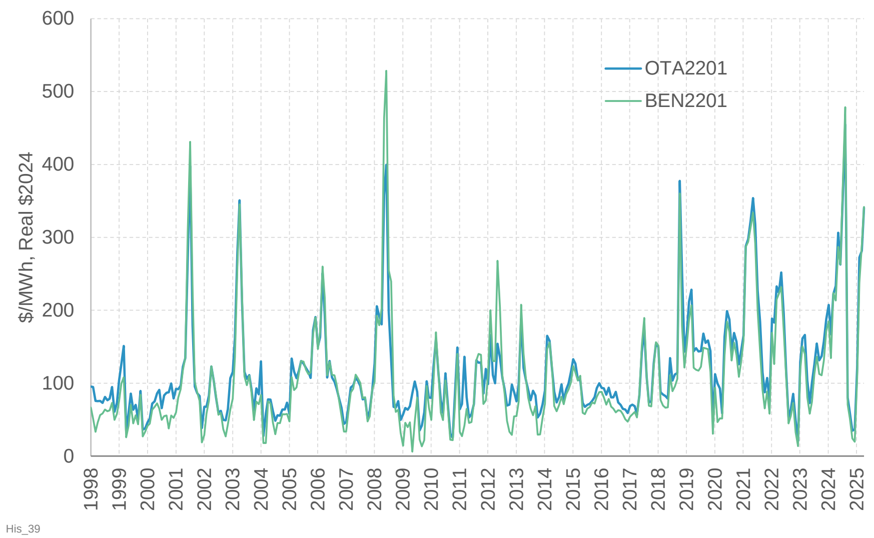
4 Breakdown of prices

This section provides information on the flow-through of high wholesale prices to electricity consumers.

4.1 Wholesale market prices – past and present

Spot prices are currently very high, as indicated in Figure 29. While prices have spiked as high (or even higher) at times in the twenty-seven year history of the market, there has been a clear step up in both average price and volatility since 2018.

Figure 29: Monthly average spot prices at the main ASX nodes (real $2024)



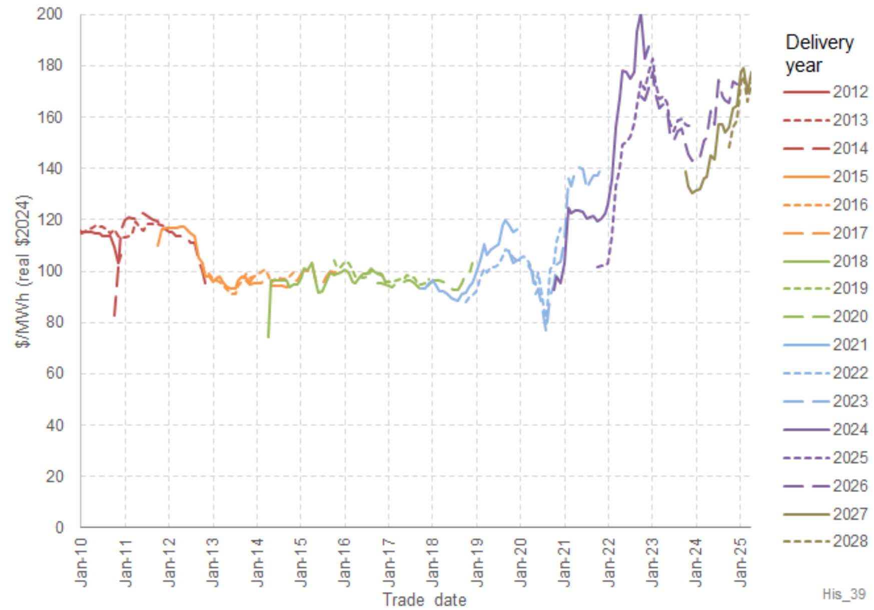
Source: Concept analysis of Electricity Authority data

Although spot prices provide some measure of the state of the market, it is hard to distinguish the impact of weather (eg, dry versus wet hydro conditions) from the impact of overall system balance.

Prices for forward contracts traded a year ahead of settlement provide a better indication of system balance. The price for such contracts is based on a probability-weighted view of future prices, without influence from current storage levels or weather patterns.

Figure 30 shows that year-ahead (and longer-dated) contract prices were relatively stable until the latter half of 2018, and have since risen materially.

Figure 30: ASX Otahuhu forward contracts for calendar year strips (real $2024)



Source: Concept analysis of Electricity Authority data

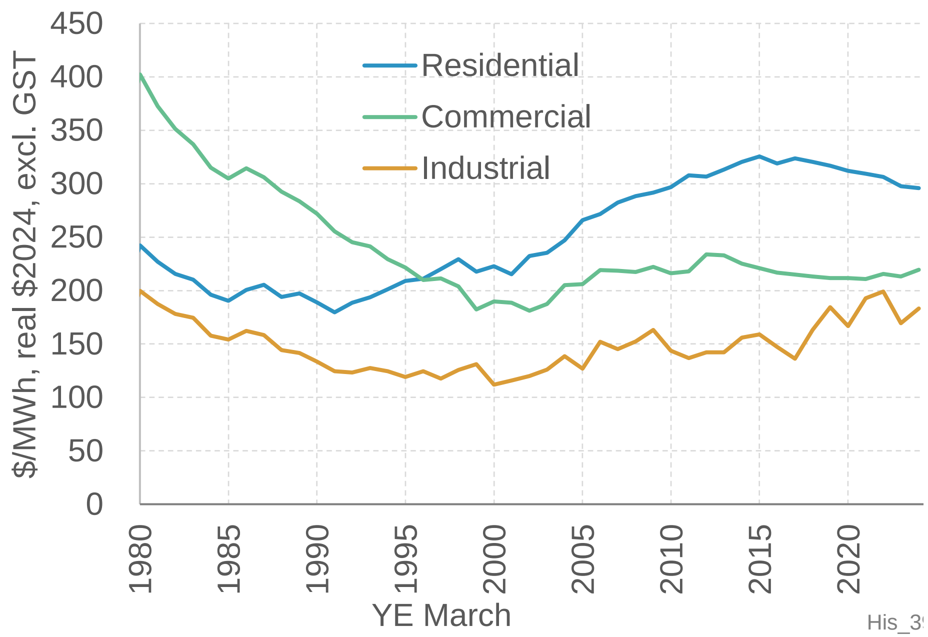
As set out in section 2.1, the rise in contract prices in the latter half of 2018 was principally due to gas supply scarcity, which translated into high gas prices and high thermal generation costs.

As further set out section 3.1, gas producers then consistently projected that gas supply would be restored, which would return gas prices back to more balanced levels – thereby suppressing the signal to build new renewable generation to displace high-cost thermal stations. However, the gas scarcity situation actually got steadily worse. As such, contract prices remained at the elevated levels we are currently experiencing.

4.2 Consumer prices

Figure 31 shows the average electricity prices paid by three different consumer segments since 1980. The prices are presented on an average price basis – that is, they are calculated by dividing the total paid by all consumers in a group (ie, the sum of all variable charges and fixed charges) by the total energy (GWh) consumed by that group. We refer to this as the “fully variabilised” price.

Figure 31: Average electricity prices (real $2024)



Source: Concept analysis of MBIE data

Figure 31 paints a very different picture for each of the consumer groups – particularly between residential and business consumers.

From 1990 to 2015, residential consumers experienced significant price increases. It was therefore no surprise that a Ministerial review into electricity prices was announced shortly after that peak. A key finding from that review was that a significant factor driving this increase in electricity prices was a change in the allocation of shared electricity networks costs – away from business consumers and towards residential consumers. This change in network cost allocation was a key reason why commercial consumers enjoyed a reduction in electricity prices from 1980 through to 2000.

Since 2015, however, the relative fortunes of consumer groups appears to have reversed. In particular, residential consumers have enjoyed real price decreases, whereas industrial consumers have faced material price increases.

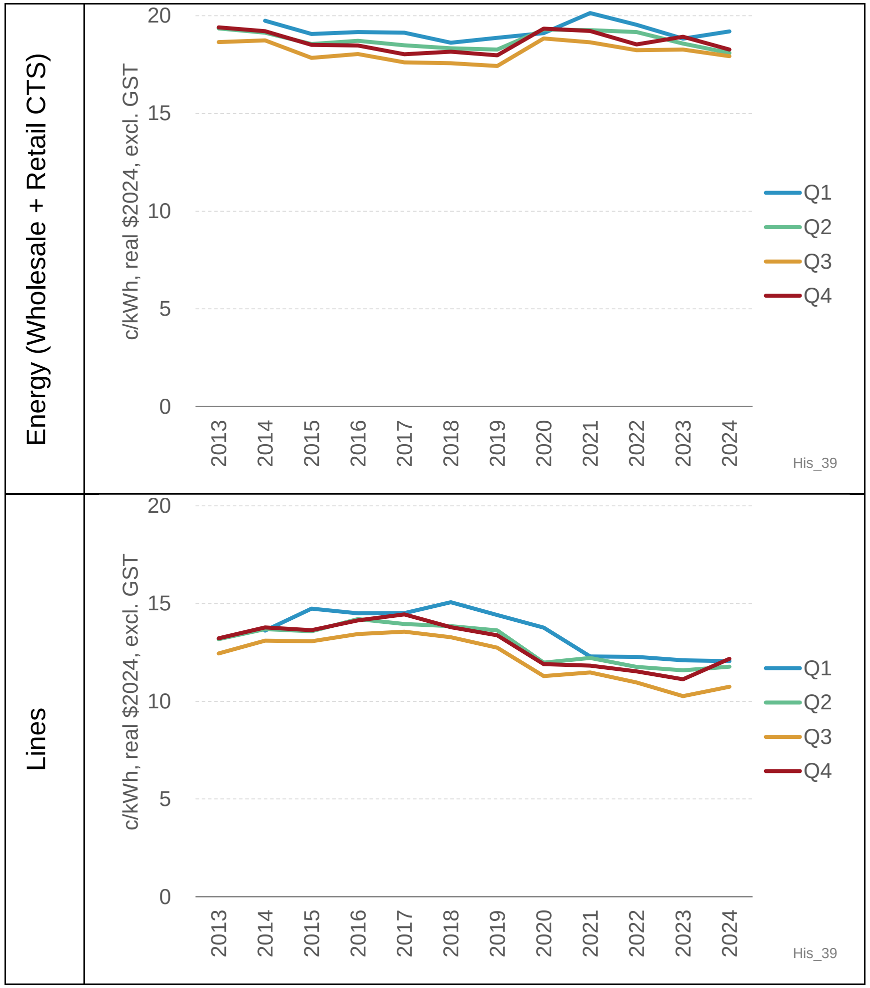
Figure 31 presents data on a year-end March basis, so data for the most recent year-ending March 2025 has not been released.

However, MBIE produces another data set that provides quarterly updates on prices paid by residential consumers – again on a fully variablised basis. This dataset also breaks electricity prices down between:

- energy charges (covering wholesale electricity, plus metering and other retail cost-to-serve costs), and
- lines charges (covering Transpower and electricity distribution costs).

Figure 32 presents this data for the period from June 2013 to December 2024. The data is presented on a quarterly basis to better allow comparison between years. This is because the variablisation process causes quarters with low demand (ie, Q1) to apparently have higher prices than quarters with high demand (ie, Q3). This is because fixed charges are spread over a greater number of kWh in Q3 than in Q1.

Figure 32: Change in components of residential electricity prices



Source: Concept analysis of MBIE data

Figure 32 shows that the energy component of residential electricity prices has fallen in real terms since 2020, including for the most recent year (2024).

However, after a period of steady decline, the lines component of residential prices has started to tick up again, with the latter two quarters of 2024 being higher than the same quarters for 2023. For most of the lines sector, this reflects outcome of five-yearly regulatory revenue “resets”. The most recent reset took effect from 1 April 2025 and increased revenue allowance by around 8% on average to reflect higher financing costs, input costs and investment levels.[15]

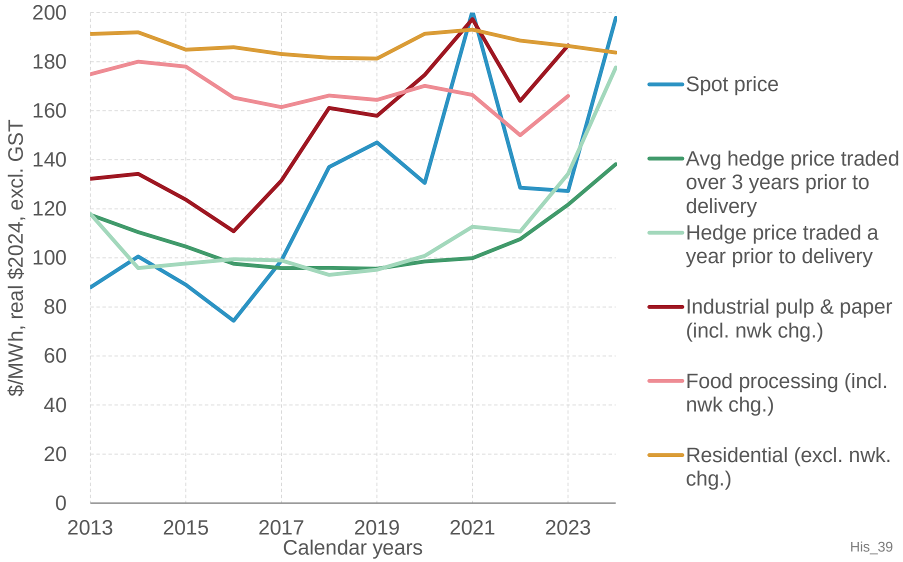
Figure 33 presents a composite of various different annual average price metrics, to enable comparison of the extent to which the increase in wholesale prices has flowed through to different classes of electricity consumer. The data shows:

- three different wholesale price metrics:[16]
  - spot prices
  - hedge prices traded one year prior to delivery
  - the average of hedge prices traded from one to three years prior to delivery
- three different consumer price metrics:
  - the energy component of residential prices
  - industrial pulp and paper prices (including the lines component)
  - food processing prices (including the lines component).

15 The Commerce Commission provides more information on its website. https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-lines-and-transmission-charges-what-are-they,-why-are-they-changing-and-what-does-this-mean-for-your-electricity-bill

16 All three price metrics are load-weighted average of Otahuhu, Haywards, and Benmore nodes, using the following simple load weightings: Otahuhu (55%), Haywards (15%), and Benmore (30%).

Figure 33: Various annual average price metrics (Real, $2024)



Source: Concept analysis of MBIE and Electricity Authority data

The slight fall in the energy component of residential electricity prices (in real terms) from 2021 to 2024 suggests some combination of:

- retailers hedging wholesale prices across multiple years – for example, adopting rolling three-to-four-year 'book' of hedge contracts (with their retail commitment hedged using a blend of year ahead, two-year ahead, etc hedges).
- reductions in the metering and retail cost-to-serve components of retail pricing
- reductions in the net margins earned on retail sales.

We do not have data to determine how much each of these factors may have contributed to this fall in the energy component.

That said, the scale of compression between year-ahead contract prices and retail prices suggests that multi-year hedging must have played a material role. This implies that the energy component of residential prices will increase as higher contract prices roll into retailer hedge books.

Despite the food processing and pulp & paper sectors having broadly similar total electricity demands (as shown in Figure 35 in section 5 later), their price outcomes have been very different.

The higher starting price for food processing is likely because a greater proportion of this demand is connected at the distribution network level, rather than as 'direct connects' to the transmission network. This may also explain some of the reductions in prices for this sector from 2015 through to 2022, noting that, as illustrated in Figure 32, the lines component of residential electricity charges also reduced during this period.

However, the relative changes in price outcomes between food processing and pulp & paper is most likely explained by differences in contracting approach for the wholesale energy component of electricity purchases. It appears that the pulp & paper sector has adopted a strategy which, relative to the Food Processing sector, is consistent with:

- a higher proportion of electricity purchased on a spot basis
- shorter-term contracting (eg, one to two years ahead rather than a rolling book over a longer period of time)

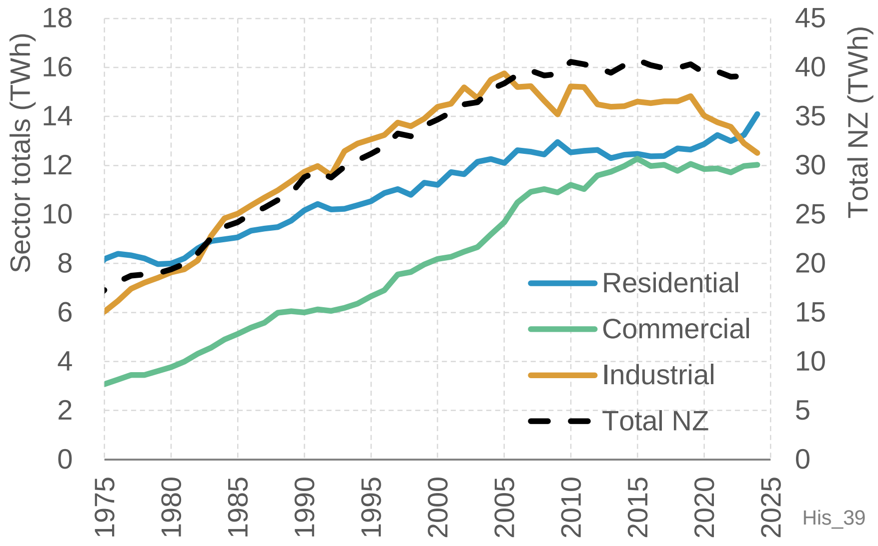
This would explain both the relatively low prices enjoyed by pulp & paper before 2018, and the comparatively steep rise since – ie, closely tracking spot prices.

5 Energy-price-driven de-industrialisation

This last section addresses the extent to which energy prices have driven de-industrialisation in New Zealand, and whether any such energy-price-driven de-industrialisation is likely to continue.

Figure 34 shows that, after at least three decades of almost uninterrupted steady growth, industrial electricity demand abruptly stopped growing in 2005. For the next fifteen years it declined slightly, before starting a more rapid decline from 2020 onwards.

Figure 34: New Zealand sectoral electricity demand



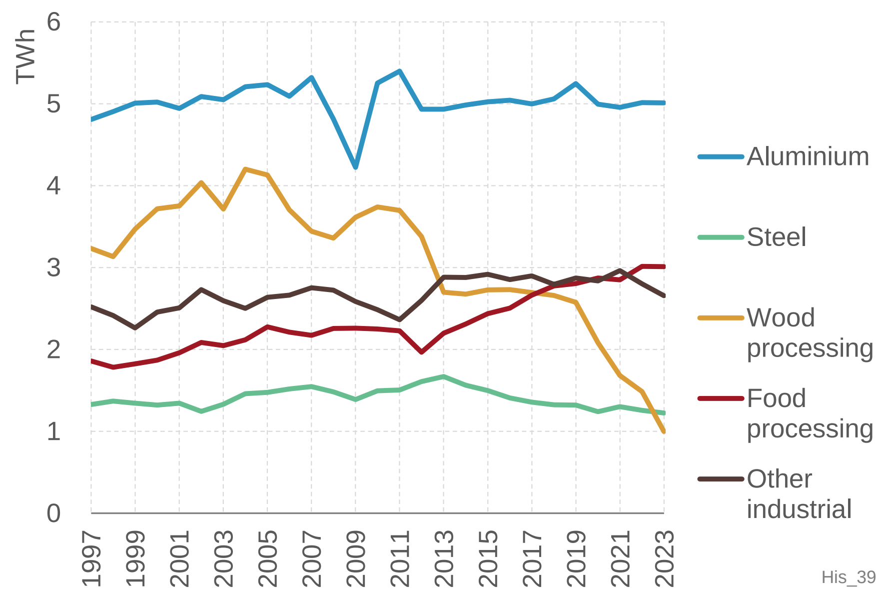
Source: MBIE data

This pattern has raised concerns that the current situation of very high electricity prices are a significant causal factor behind this apparent 'de-industrialisation' of New Zealand, and that high electricity prices are likely to result in a continuation of this downward trend.

Figure 35 provides a more detailed breakdown of the demand across different industrial sectors from 1997 (the earliest that this information is available). It reveals significant variations between industrial sectors:

- only one sector – wood processing – shows a steep decline since 2005, having been behind much of the growth in the seven years prior
- three sectors – aluminium, steel, and 'other' – have had broadly flat demand
- one sector – food processing – has shown strong demand growth, particularly over the past decade

Figure 35: Industrial sector annual electricity demand



Source: MBIE data

While Figure 35 helps understand what has happened to date, it provides little information as to whether other sectors may start to reduce demand in response to sustained high electricity prices.

Sectors at risk of electricity-price-driven de-industrialisation have two characteristics. They must be:

1. electricity intensive – ie, electricity is a big enough portion of their input costs to matter
2. unable to pass increased electricity prices through into higher prices for their products. This mainly applies to firms facing international competition.

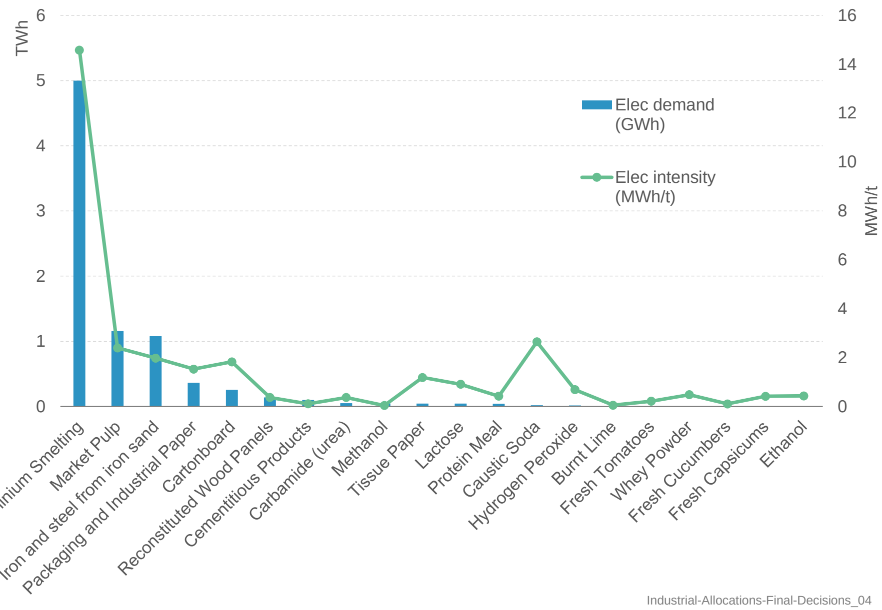
The industrial allocation mechanism in the Emissions Trading Scheme (ETS) provides good information on sectors that have these characteristics. This mechanism was set up to protect Emissions-Intensive Trade-Exposed (EITE) firms who faced higher costs due to a New Zealand carbon price.

Importantly, this mechanism recognised that higher costs could be due to direct emissions of greenhouse gases or due to carbon prices increasing the price of electricity. Information collected and published as part of the industrial allocation process enables identification of which sectors are electricity-intensive and exposed to international competition.

Figure 36 sets out Concept analysis of data published by the Ministry for the Environment as part of the industrial allocation process. It covers all the sectors covered by industrial allocation (ie, all sectors who face international competition and whose direct emissions or electricity consumption is high-enough to warrant material concern regarding price-driven exit). It shows:

- the electricity intensity of the product (expressed in MWh per tonne of the product), and
- the sector's total electricity consumption for 2022.

Figure 36: Electricity intensity and 2022 electricity demand of EITE industrial sectors



Source: Concept analysis of MfE data

The key take-away from Figure 36 is that there are only three industrial sectors that are both significant consumers of electricity <u>and</u> electricity intensive <u>and</u> trade exposed:

- aluminium production
- steel production
- Wood processing, split between:
  - market pulp
  - packaging and industrial paper
  - cartonboard

– reconstituted wood panels

– tissue paper.

These should be the principal sectors where high electricity prices could result in large-scale de-industrialisation. Other sectors are either:

- not electricity-intensive (and so not too exposed to electricity prices)
- too small to materially impact overall New Zealand electricity demand, or
- able to pass-through higher electricity costs to a reasonable extent.

Turning to the three sectors that are both large and electricity-intensive, only wood processing looks to be at risk of further demand reduction. Even then, the scale is likely to be limited as, sadly, there is not much electricity-intensive production left to exit.

With reference to Figure 35, 2023 wood processing electricity demand fell by approximately one-third compared to 2022 demand. The closures announced in 2024 will have resulted in additional falls, partially offset by the Whirinaki mill re-opening in 2024 following repairs from cyclone Gabrielle.[17] We estimate that 2025 wood processing demand will be approximately 0.9 TWh, which is 21% of the level in 2005.

It is hard to estimate the extent to which the remaining wood processing facilities are likely to exit due to electricity prices. This is because there is considerable variation in the:

- electricity-intensity of the different types of wood processing facilities (eg, as between pulp – noting there is also significant variation between kraft and mechanical pulp processes – paper, cartonboard, etc,)
- international commodity prices for each product, and the extent to which New Zealand production is for domestic consumption (and so protected by shipping costs, facing import parity pricing) or export overseas (facing export parity pricing).

Nonetheless, it is reasonable to assume the most vulnerable operations will have exited first – ie, with the worst combination of electricity intensity and commodity prices.

Remaining firms have demonstrated a greater ability to weather current pricing levels but could be exposed if prices were to rise further. In that respect, forward contract prices, while remaining high, are showing some decline. As set out in section 2.2, our modelling of the system balance indicates there is a reasonable hope of contract prices falling faster than the forward curve currently indicates.

However, while significant additional electricity-price-driven exit in the wood processing sector seems unlikely, it is potentially the case that additional exits could occur for other reasons. In particular, as set out in section 3.3, the current situation of extreme scarcity in the gas sector risks further industrial wood processing closures due to the inability to source gas. In this respect, it is notable that at least one of the recent wood processing closures was principally due to gas scarcity, not electricity pricing.

This risk of gas scarcity driving further de-industrialisation, doesn’t just apply to wood processing, but to other gas-intensive industrial sectors. In particular, the petrochemical sectors producing methanol and urea:

- Methanex have already shut two of their three methanol production trains, and there is a realistic possibility of remaining train shutting down within the next two to three years unless significant new gas resources are brought to market
- the prospects for the Ballance urea production facility look stronger in the short term as it has contracted forward for a number of years.

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[17] Estimated losses of 140 GWh from the Oji-owned Kinleith & Penrose mills, and 230 GWh from the Winstone-owned Tangiwai & Karioi mills. Estimated increase of 295 GWh from the re-opening of the Whirinaki mill.

However, this is likely the next major gas-consuming facility to exit if the decline in gas production continues.

Turning back to electricity, of the other two large electricity-intensive sectors the outlook looks strong:

- the Tiwai aluminium smelter has started a tender process for long-term electricity supply to *increase* production, and
- the Glenbrook steel mill has signed a long-term electricity supply contract with Contact Energy, and is making a significant investment in an electric arc furnace.

Other industrial sectors are also investing in electrification projects that should increase electricity demand. Most notably:

- Fonterra has announced major investments to electrify three of its North Island factories over the next 18 months, moving away from gas and coal-fired boilers at these sites, and
- multiple parties are investing in large, energy-intensive data centres.

In summary:

- only the wood processing sector appears to have materially reduced electricity demand through exiting New Zealand production as a result of high electricity prices – accelerating a process that had started prior to electricity prices increasing from 2018
- the worst of these electricity-price-driven closures for the wood processing sector appear to be over
- other industrial sectors appear unlikely to exit due to electricity prices, and
- some parts of the industrial sector are investing to increase electricity demand, including to reduce their direct exposure to gas scarcity, but
- that is not to say there won't be other reasons why some industrial electricity consumers exit New Zealand. In particular, continued gas scarcity could cause further industrial closures (which would also result in a fall in electricity demand).