Review of proposed dry-year reliability obligation

20 July 2026

concept

About Concept Consulting Group

We have been providing useful, high-quality advice and analysis for more than 25 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 applied our skills to assignments in telecommunications and water infrastructure.

Our directors have 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.

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Executive summary

Concept was engaged by Contact, Genesis, Mercury and Meridian to test the diagnoses and prescriptions in the Government's consultation on a proposed reliability obligation to manage dry-year risk. The conclusions in this summary are our own independent assessment.

In short, we do not consider that the case for the proposed obligation has been made out.

The proposal rests on an assessment that current arrangements produced an "intolerable reliability risk" in winter 2024, and that a new administrative regime is therefore needed. Our analysis points the other way.

The market performed relatively well through the significant dislocations of 2024; the risks the system now faces are different from, and broader than, dry-year risk; dry-year firming cannot be separated from the wider task of balancing supply and demand; and the proposed obligation would most likely *raise* prices for consumers while altering – rather than reducing – supply risk.

We recommend enhancing the existing energy-only market and improving gas market arrangements, rather than shifting planning and risk management to administrative decision-makers.

2024 was a hinge year, not a market failure. The stresses of winter 2024 were principally driven by a sharp unexpected fall in gas production relative to producers' own recent projections, compounded by years of unresolved uncertainty over the Tiwai smelter – not by extreme hydrology, which was only moderately dry. These were one-off drivers marking a 'hinge' in the transition to a highly renewable system.

Despite this, controlled hydro storage never reached 'watch' status, the System Operator called neither a conservation campaign nor its rolling-outage plan, and most purchasers – including smaller retail consumers – were insulated from spot prices through hedging. Reservoir levels were preserved without recourse to the emergency measures used in the past.

On any fair reading, market arrangements coped well with an exceptional set of circumstances.

The market also self-corrected quickly. Meridian drew on a demand-response mechanism built into its new supply agreement with the Tiwai smelter; Genesis and Contact secured agreements with Methanex to divert gas from methanol production to electricity generation; the four large generators subsequently obtained Commerce Commission authorisation for the Huntly Firming Options over the Rankine units; and new renewable generation is rapidly rebalancing the system to address reduced gas availability.

These responses, alongside the spot-price signal, averted more severe stress – evidence that the energy-only market already has the tools to respond to dislocation without a new obligation.

Continued decline in gas is now expected, rather than a surprise. From 2019 to 2024 the gas producers were constantly projecting that the forthcoming drilling campaigns would return the gas system (and associated gas prices) to balance within two years. This significantly supressed investment in renewable generation to displace high-priced thermal generation. The subsequent massive under-supply of gas (2024 production was 45% less than the producers' forecast released less than two years prior), left the electricity market significantly short of generation.

Looking forward, the downside risk of gas production is significantly less as there is now not the same scope for further disappointment. Furthermore, the government is seeking to improve gas market disclosures, particularly around downside risk.

The electricity market is responding to this revised gas outlook by building renewable generation and increasing the Huntly coal stockpile to significantly reduce the need for gas-fired generation

The challenges ahead are different – and dry-year risk is receding. Since 2024, renewable supply and grid-scale battery capacity have grown quickly, confidence in Tiwai's future has improved, and the decline in domestic gas is now an expected outcome rather than a surprise.

By the start of 2026 the mean need for thermal generation to cover hydrological variation had fallen by around 40% relative to the start of 2024, and by 2028 is likely to be 70% less than 2024. Forward prices for the 2027 to 2029 calendar years have fallen by 34% to 25%, respectively, since the start of this year.

The system's exposure to dry-year risk is therefore receding, not increasing as the consultation paper states.

The risks that will matter most in future are different: winter capacity margin during multi-day lulls in wind and sun ('dunkelflauten'), and the challenge of matching a build programme that will be larger than any point in New Zealand's history to strong, and potentially step-changing, demand growth.

Designing today's regime around dry-year risk alone risks gearing up to fight the last war.

Dry-year firming cannot be separated from the rest of the system. Intermittent renewables must be firmed, but a reduction in thermal generation does not have to be replaced one-for-one by another fuel source.

Hydro is operated dynamically, and firming duty is shared across hydro, thermal, batteries, demand response – and even additional wind and solar, which can substitute for thermal fuel in an optimised system. There is no bright line between dry-year firming and other firming; dry-year variability is simply one dimension of a continuous, whole-system optimisation. Attempting to carve it out and manage it administratively would inevitably distort that optimisation.

Administrative planning would not do better. It is inherently difficult to optimise the supply mix over time, and administrative decision-makers do not have better information or incentives to get it right. They see less than the market as a whole, are vulnerable to under-funding, and face institutional incentives to over-procure – because shortages are treated as failure while the cost of over-supply is hidden.

The Security of Supply Assessment that would anchor the proposed regime illustrates the point: recent assessments have persistently over-projected demand, by an average of around 9,250 GWh three years out for the 2021 to 2023 assessments, and by around 5,000 GWh even one year out over the last three years.

Notably, the two drivers of 2024 – an unexpected rapid reduction in gas supply and chronic uncertainty over Tiwai's future – would have challenged a reliability-obligation administrator just as much as they challenged market participants.[1]

The proposal would distort incentives and raise prices. The proposed long-term and near-term obligations, reinforced by penalties, would overlay administrative judgements of need and acceptable response onto the nodal prices and contracts that currently coordinate investment and operation. We expect the net effect to be higher consumer prices and altered – not reduced – risk.

The cost impacts are additive:

- a conservative margin for dry-year cover raises total system cost, and hence prices. If an overly conservative margin of a scale similar to the past SOSA over-projections of demand were

[1] The fact that the most sophisticated gas market participant, Methanex, invested huge amounts of wasted money in their methanol trains in anticipation of expanding output when they actually needed to be shut, indicates how challenging the gas market problems were to forecast.

to emerge, we estimate average prices to consumers would be higher by approximately $11 to $39/MWh – ie, an uplift in excess of 10%

- managing dry-year risk in isolation causes sub-optimisation and constrains innovation, raising cost and worsening other risks
- because the obligations are proposed to fall only on large gentailers, retail and contract competition would be dampened and margins would expand – our modelling indicates this partial obligation coverage would further drive retail prices by around $11/MWh higher, and increase costs to the Tiwai smelter by around $8.5/MWh
- fuel suppliers gain an incentive to price up towards penalty levels – we estimate further increasing prices by ~1-2%, and
- independent (non-portfolio) generation entry becomes more difficult.

In aggregate, the proposals would almost certainly reduce the scale of spot price increases during dry years.

However (and it is a very big however), it is not the case that reducing dry-year risk simply flows through to lower prices due to a lower risk premium. This would be true if risk reduction were costless, but it is not – and higher system cost must ultimately flow through to higher prices, even if this is through consumer prices rather than wholesale spot prices.

Overall, under the current proposals, we estimate the average wholesale component of prices to consumers will *increase* in a range between $15 to $50/MWh.

It is not clear that it is worth increasing the average wholesale component of prices to consumers by ~13% to 42% to reduce dry year risk – particularly when consumers already have the ability to protect themselves from the impacts of high prices during dry years through contracting forward with suppliers.

Current arrangements should be enhanced, not replaced. Enhancing the energy-only electricity market and the operation of the gas market would be less disruptive, less risky, and more effective than a new administrative regime.

We recommend focussing on three pillars of a well-functioning market:

- information – better and more timely gas-market disclosures, price discovery and price transparency, so the system can respond to gas risk earlier and reallocate scarce gas efficiently
- incentives – refining the stress-test disclosure regime (including publishing high-level, firm-level insurance metrics rather than full anonymisation) to reinforce purchasers' incentives to manage their own price exposure rather than seeking political intervention if they under-hedge and get caught out by a dry year, and
- ability to contract – improving access to the full range of hedging instruments, from exchange-traded super-peak products to over-the-counter arrangements such as swaptions and long-term power purchase agreements, that support efficient investment and risk management – as well as considering options for addressing dislocation risks (such as bring-your-own generation for large new demands).

Making substantial changes now to solve yesterday's problem risks worsening tomorrow's – above all the need to keep expanding supply rapidly to meet growing demand.

Targeted enhancements to information, incentives and contracting would address the genuine weaknesses that 2024 exposed, without the far-reaching costs and distortions of the proposed reliability obligation.

1 Introduction

The government is consulting on a proposed "reliability obligation to manage dry-year risk".[2] The proposal rests on an assessment that current arrangements have led to "intolerable reliability risk", so new arrangements are needed.

Concept was engaged by Contact, Genesis, Mercury and Meridian to prepare a report in response. Our report tests the diagnoses and prescriptions in the consultation paper. While we have benefited from input and feedback from our clients, this paper and its conclusions convey our own independent assessment.

Our report is structured around the following observations:

- electricity market arrangements actually performed relatively well in winter 2024 given the major dislocations the market experienced. A dramatic fall off in gas production, coupled with resolution of years of Tiwai uncertainty, made 2024 a 'hinge' year in the transition to a highly renewable system
- current and future challenges are different from 2024 – the electricity system has evolved quickly, and dry-years are not the biggest challenge
- dry-year firming is not separable from other firming – resources are optimised dynamically (and even intermittent renewables add to firming)
- proposals would fundamentally alter market arrangements – the proposals shift key elements of planning to administrative decision makers
- setting requirements administratively is not superior – planners would not have better information and incentives than suppliers to identify and manage risks
- proposals would distort incentives – proposed obligations and penalties would have far-reaching impacts on market performance, and likely result in higher wholesale and retail prices for consumers
- current arrangements should be enhanced instead – enhancing the energy-only market would be less risky and more effective.

To support these observations, we have derived insights through:

- analysing publicly available data on historical market performance
- using our proprietary system modelling software (ORC) to project future performance.

We routinely use ORC to generate insights, including:

- long-term price forecasts – we produce updated forecasts each quarter that project how the shape and level of electricity prices are likely to evolve given fundamentals of supply and demand
- investment analysis – we help investors assess the revenue they may earn (for suppliers) or costs they may incur (for consumers) for projects across a range of technologies
- policy analysis – we help policy makers assess market performance and test the impact of policy changes on market dynamics and consumer outcomes.

[2] https://www.mbie.govt.nz/have-your-say/a-proposed-reliability-obligation-to-manage-dry-year-risk

2 2024 was a hinge year

The proposed reliability obligation is predicated on an assessment that current electricity market arrangements failed to deliver acceptable outcomes in winter 2024.

2024 was a moderately dry year. Hydro storage was relatively low heading into 2024, and precipitation was below average across the first nine months of the year.

Rather than extreme hydrology, the key drivers of system stress in 2024 were:

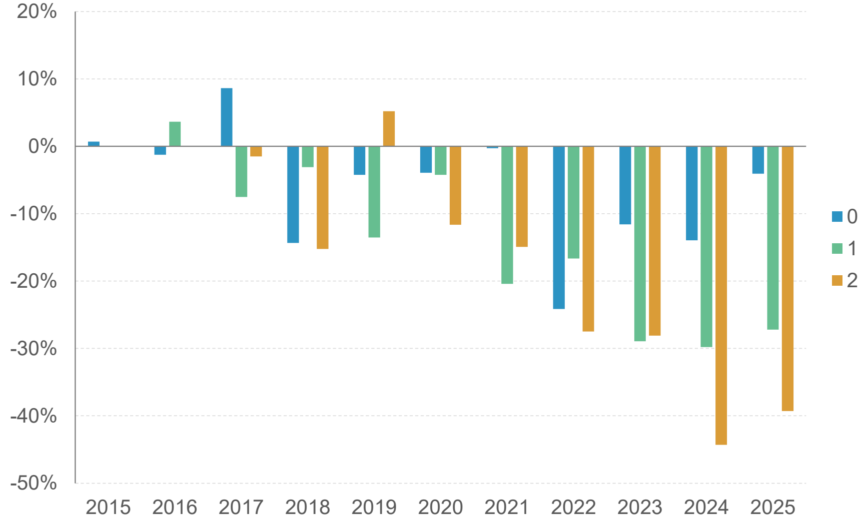
- a dramatic fall off in gas supply compared to projections from gas producers published less than a year prior
- chronic uncertainty over many years regarding continued operation of the Tiwai smelter (which was not resolved until mid-2024).

Poor signals from the gas market significantly destabilised the electricity market

After years of relatively stable production and associated stable gas prices, the gas market started to have problems in 2018 with the unexpected failure of offshore wells at the Pohokura gas field – at that point New Zealand's largest gas field – causing shortage and higher gas prices.

As Figure 1 illustrates, this started a pattern from 2019 to 2024 of gas producers constantly projecting that forthcoming drilling campaigns would return the gas system to balance (and associated lower gas prices) within two years – but with the drilling campaigns failing to deliver.

Figure 1: Difference between actual production, and production projected by gas producers 'x' years previously



This constant projection of a return to a balanced gas system and associated low gas prices within two years (crucially, without any projections of possible down-sides) significantly supressed investment in renewable generation to displace high-priced thermal generation. The subsequent under-supply of gas (2024 production was 45% less than the producers' forecast released less than two years prior), left the electricity market significantly short of generation.

This physical decline in gas supply was exacerbated by a deliverability lock-up – ie, arrangements were not in place ahead of 2024 to redirect gas from methanol production to electricity production in the event of scarcity.

Tiwai uncertainty drove under-investment in generation

In 2021, Transpower's security of supply assessment (SOSA) had a Tiwai exit as its central projection, whereas in the 2022 to 2024

SOSAs a Tiwai exit was considered possible rather than the most likely outcome, with market analysts assigning a similar likelihood.

It is hard to determine exactly how much this suppressed investment in generation. However, even if the effective collectively assessed probability was only a 1-in-5 chance of exit, this would have reduced the amount of renewable build by about 1,000 GWh. An extra 1,000 GWh of generation in 2024 would have resulted in significantly reduced prices.

The market responded

Together, the under-build of renewable generation due to the gas market failures and Tiwai uncertainty caused a supply pinch, with prices peaking at ca. $355 per MWh for the three months ending 31 August 2024.

Alongside this price signal, key responses to the conditions included:

- Meridian called on a demand response mechanism built into its recently concluded supply agreement with the Tiwai smelter. This reduced demand from June to September
- by August (just before hydrology improved), Genesis and Contact finally secured agreements with Methanex to divert gas from methanol production
- wood processors Winstone Pulp and Oji Fibre paused production, and went on to cease operations altogether
- in November 2025 (after hydrology had improved) Genesis, Contact, Meridian and Mercury gained Commerce Commission authorisation for a series of agreements akin to option contracts for output from the Rankine units at Huntly (Huntly Firming Options).

These actions averted more severe system stress, including:

- controlled hydro storage did not reach ‘watch’ status (representing a 1% risk of shortage) or ‘alert’ status (representing a 4% risk)
- the System Operator did not initiate an official conservation campaign, which involves encouraging the public to conserve energy[3]
- the System Operator did not initiate its rolling outage plan, which is used to manage and coordinate planned outages as an emergency measure during energy shortages.[4]

A high profile sign of stress through 2024 was the financial impact of elevated spot prices on unhedged industrial consumers, particularly in the wood processing sector. For context:

- high prices for the three months ending 31August 2024 approached within 10% of the winter quarter ‘stress test’ scenario that purchasers are required to assess when making risk management disclosures
- the average spot price of ca. $355 per MWh for the three months ending 31 August 2024 compares with a price of less than $150 per MWh for the 2024 calendar year that would have been obtained by a purchaser that had chosen to hedge on a rolling three-year basis (ie, for a given year, purchase hedges to cover one-third of the requirement three-years prior, one-third two-years prior, and one-third one-year prior).

3 Public conservation campaigns have not been used since 2008. There were three campaigns from 2001 to 2008, and eight from 1974 to 1992.
4 Rolling outages and demand cuts were common through the 1940s and 50s, with shortages every year from 1941 to 1953 and summer drought conditions in 1958.

While periods of supply stress and elevated prices are understandably concerning, market arrangements actually performed well in 2024. In particular:

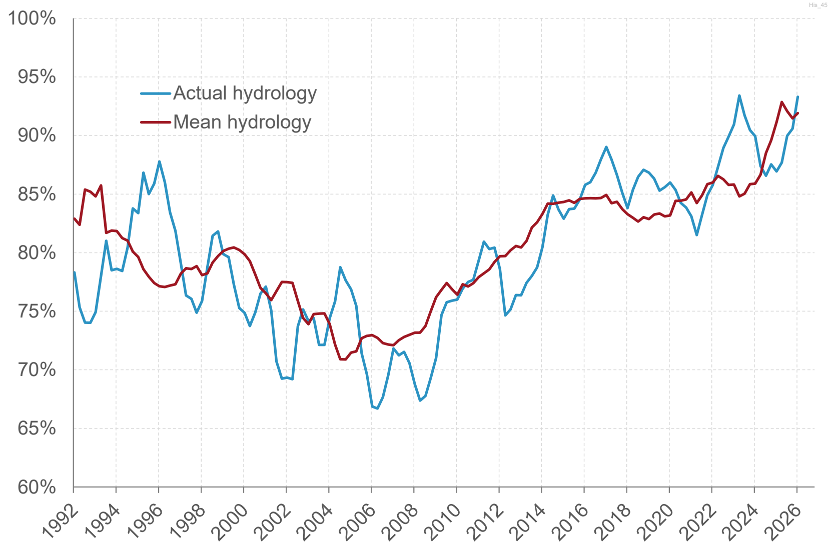
- hydro reservoir levels were preserved without recourse to the more disruptive emergency measures that have been used in the past
- purchasers had an opportunity to insulate themselves from elevated spot prices (and most did, including smaller retail consumers).

Importantly, the drivers for system stress in 2024 were a one-off occurrence. 2024 was a 'hinge year' in the transition to a (even more) highly renewable electricity system. Post-2024:

- there is more confidence regarding the future of the Tiwai smelter
- declining domestic gas production is an expected outcome – ie, projected new gas is more modest, so there is much less exposure to the risk of major drilling campaigns failing to deliver

Accordingly, renewable supply has since grown considerably, along with utility-scale battery installations. By the start of 2026, mean hydrology need for thermal had dropped by 40% relative to start of 2024. By 2028, it is likely to have dropped by more than 70%.

Figure 2: Percentage generation (excl. cogen) from renewables - rolling 4-quarter basis



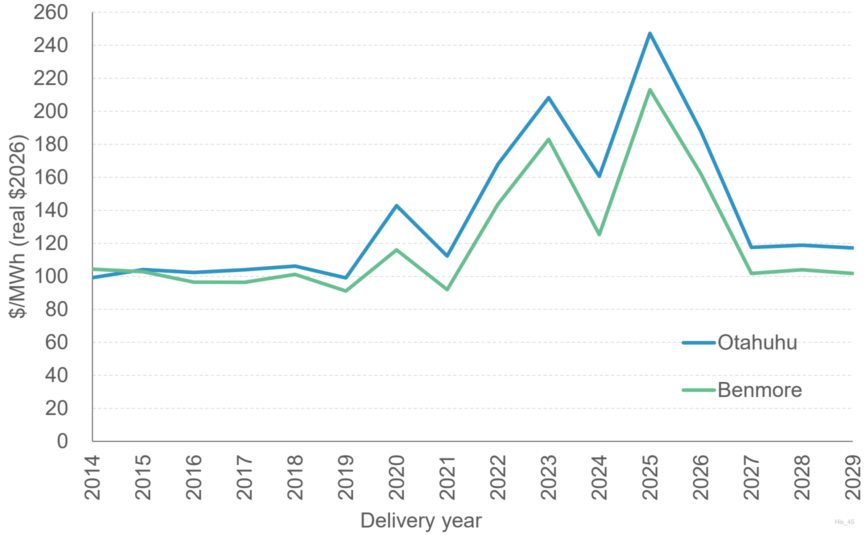
The Huntly Firming Options have also provided an improved basis for sustaining investment in the Huntly Rankine units and stockpiled coal until 2035.[5]

Furthermore, gas-fired generators have secured ex-ante agreements for Methanex gas entitlements to be traded to power generation in the event of a dry year.

This material improvement in supply outlook is clearly reflected in forward prices.

[5] The agreements do not guarantee operation through to 2035, but mark a significant step forward in the commercial foundation for continued operation.

Figure 3: ASX hedge prices for yearly strip traded seven months prior to start of year (except for future three years)[6]



Futures contracts for 2027 to 2029 are now trading at prices close to the long-run marginal cost of supply. This is consistent with the system supply-demand balance reaching a new equilibrium with less gas and more renewable supply.

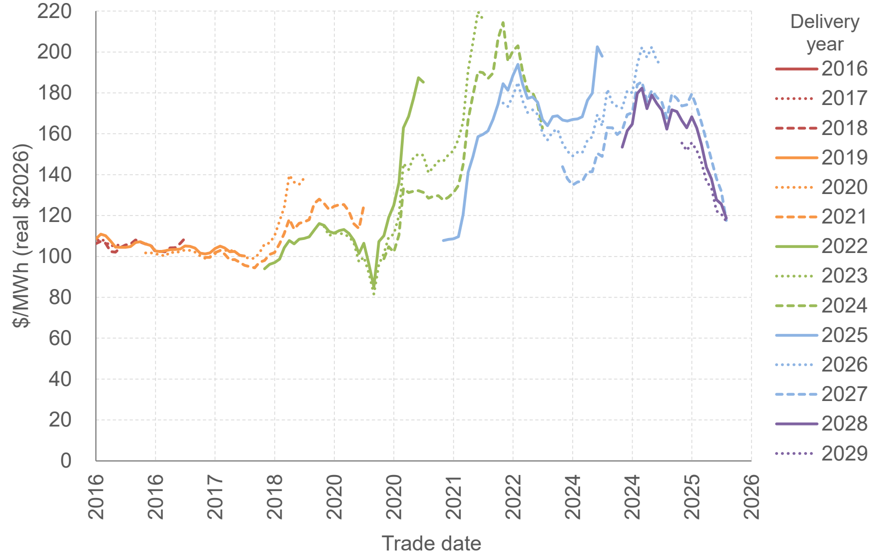
Indeed, there now appears to be a very real chance of the system moving into a situation of *over*-supply – an outcome that an increasing number of market analysts are projecting could occur in the next few years.

3 Challenges are different now

Having traversed the 2024 hinge year, the market is rapidly moving to a new equilibrium, responding to revised expectations regarding gas supply and the Tiwai smelter.

This change in price levels has been driven by rapid expansion of renewable supply. As illustrated in Figure 4, since the start of this year, the forward prices for the calendar strips 2027, 2028, and 2029 have fallen by 34%, 29%, and 25%, respectively.

Figure 4: Otahuhu hedge prices excluding trades made within seven months of delivery (except for future three years)



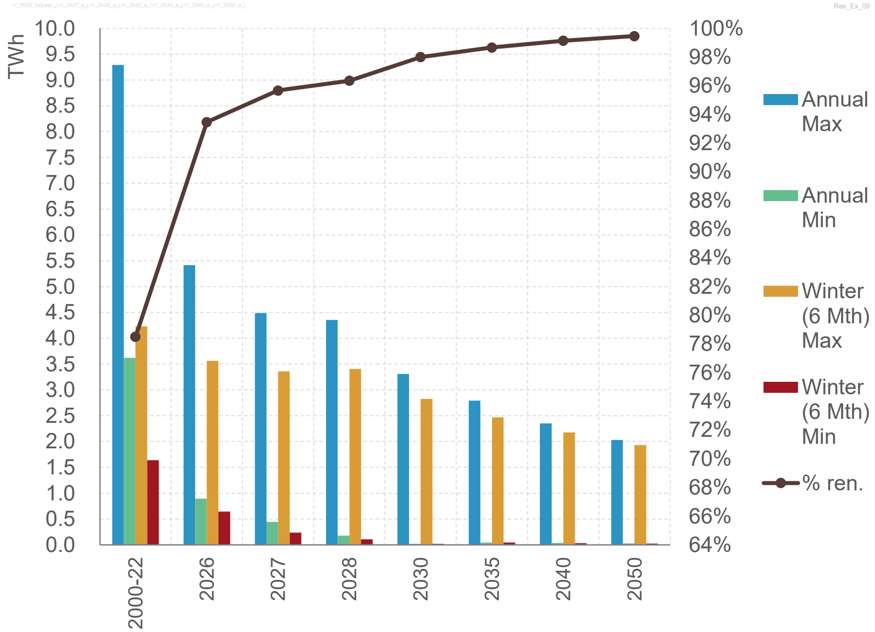
The fact that 2027 prices have fallen the furthest is a clear indication that the prospect of LNG supply is not driving this outcome – ie, because indications from MBIE are that an LNG

[6] Using prices traded seven months prior is to capture prices that were close enough to to reflect the market's expectations of the underlying supply-demand balance, but without near-term hydrology affecting expectations. Future year prices are based on the values at the time of this analysis – 13 July 2026.

import facility "could be operational by 2028", but certainly not for 2027.

As we move further beyond 2024, dry year risk is receding as a key system risk. As illustrated in Figure 5 below (and detailed further in Appendix A, the need for thermal firming has already declined and will fall further as renewables continue to expand.

Figure 5: Variation in need for thermal generation to provide flexibility duties across weather years



This is contrary to the statement in the consultation paper that the electricity system is becoming *more* exposed to dry year risk.

Our modelling indicates that, as the electricity system evolves, other risks will become more prominent.

A key risk from 2030 onwards is likely to be winter capacity margin. This is driven by the risk associated with a multi-day lull in wind and sunshine ('dunkelflaute') drawing down energy stored in batteries.

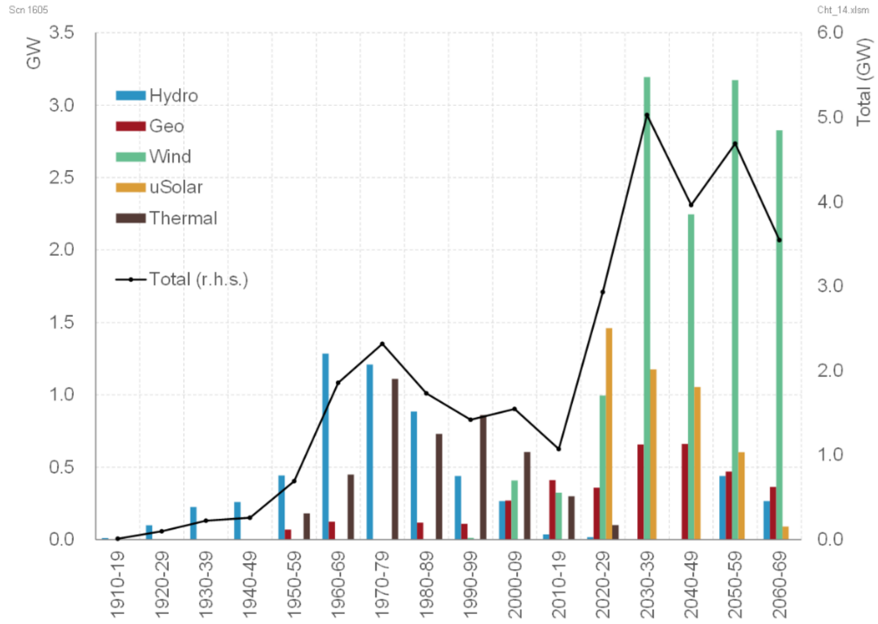
The analysis in Appendix A illustrates how a more highly renewable system will result in a much peakier post-renewable demand curve and consequent peakier need for thermal generation. In turn, this will drive peakier prices, even though the average price across weather years will be broadly the same.

Focussing solely on winter energy risks gearing up to fight the last war, when the threat has changed.

Another key risk is matching supply expansion to rapidly expanding demand. Demand is widely expected to grow strongly over coming decades as the economy electrifies. On top of this, there is the potential for step-changes from large new loads, including datacentres.

Our modelling indicates the scale of investment over coming decades is likely to be more significant than any historical period.

Figure 6: Historical and projected build by decade



As was experienced when strong demand growth through the post-war decades contributed to frequent shortages, it is inherently challenging to match supply expansion to demand growth and there are likely to be periods of over- and under-supply.

Expansion timing even played a role in outcomes during 2024. Our analysis indicates:

- demand for the first seven months of 2024 was ca. 730 GWh higher than for the same seven months in the prior two years
- commissioning delays for the Tauhara geothermal plant and Harapaki wind farm reduced supply (compared to expectations) by ca. 300 GWh.

These expansion coordination factors are likely to become more prominent as build accelerates further through the 2030s and beyond.

As the system expands, its technology mix will also evolve. This means there are technology risks for investors, including risks that:

- over-investment in a given technology collapses returns for that technology. This is particularly acute for solar developers (summer price collapse) and battery developers (reserves revenue and energy price arbitrage revenue)
- network investment fails to keep up with system expansion requirements. This includes transmission and distribution, and includes connections and upstream capacity. These risks can manifest as connection queue delays and capacity congestion.

Under current arrangements, nodal prices dynamically guide investment and operation by reflecting all these factors (and more).

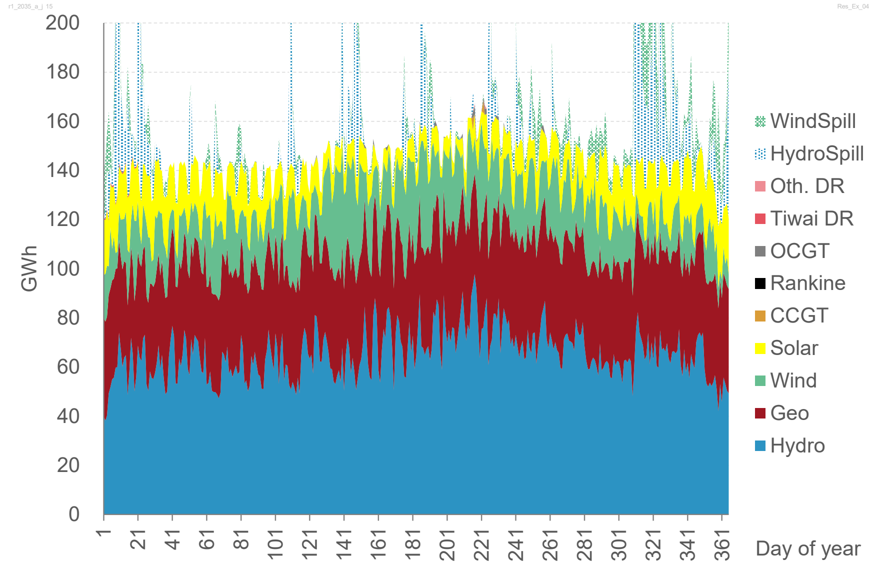
4 Firming is not separable

It is correct that intermittent renewables must be firmed to match demand, but incorrect to assume a reduction in thermal must be offset by an equivalent fuel source.

While dry years are a source of system stress, the way hydro is operated responds dynamically as the system evolves.

To illustrate these points, Concept's modelling of an optimal system for 2035 has firming met by a mix of reduced thermal plant, significantly increased renewable spill, and some increased demand response.

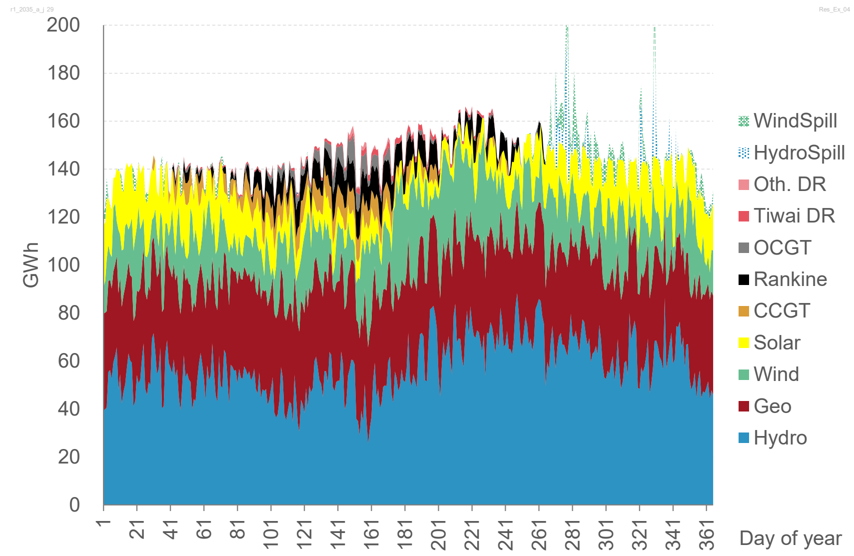
Figure 7: Modelled 2035 wettest year – daily supply



In wet years, expanded wind and solar production reduce the need to draw down hydro reservoirs. Lakes are held higher, and there is more incidence (than today) of spilling water and wind.

In dry years, the same system meets demand by producing less spill, as well as calling on some thermal generation.

Figure 8: Modelled 2035 driest year – daily supply



This optimisation shows that building more intermittent renewables can play a key role in efficiently firming a system that has less thermal fuel. This outcome is possible due to New Zealand's hydro reservoirs and the ability to optimise their operation to reflect changing system conditions – in particular, balancing variable wind and solar generation.

More generally, hydro shares duty with other technologies – thermal, batteries and demand response – across a full spectrum of firming needs. This is a dynamic process and there is no 'bright line' between dry-year and other firming resources

Renewable spill has its limits, so an optimal system also deploys demand response and some thermal generation.

It would be unrealistic to expect to build and operate a system that never called on some level demand response – a system built to never need any demand response would be very high cost, with high prices to match.

Pre-planned demand response is a relatively low-cost resource and can make a material contribution to system security. Tiwai is a key example, but there are win-win opportunities for other industrials too. These opportunities will expand with the ongoing electrification of process heating.

Non-pre-arranged demand response is more disruptive and higher cost. However, it can play a role in managing more extreme (and less probable) stressed conditions. Finally, administered load control is an unpleasant but valuable resource in the most extreme (and least probable) conditions for which supply-side measures would be prohibitively expensive.

5 Proposals would shift planning

The proposed reliability obligations would fundamentally alter how system expansion and operation is planned.

Current arrangements rely on prices to coordinate supply and demand.

The spot market uses bid-based price discovery, complemented by scarcity prices and consumer compensation arrangements. These latter two mechanisms aim to address a fundamental challenge in electricity markets around ensuring prices at times of scarcity reflect consumer willingness to pay.

Consumer willingness to pay is not directly discovered through market interaction because suppliers cannot selectively curtail individual customer (or retailer) demand based on the extent to which each customer (or their retailer) has contracted for supply.

Retailers and direct purchasers exposed to nodal prices have an incentive to manage their exposure, allowing them to determine how much they are willing to pay to avoid shortage. This in turn drives incentives for optimal supply mix across a range of conditions.

This arrangement does not involve central decision making on the optimal way of balancing supply and demand. Instead, key administrative inputs are determining the operation of scarcity pricing and consumer compensation mechanisms, and addressing information and incentives.

The proposals would fundamentally alter this by introducing administrative arrangements for assessing supply risk and validating solutions.

The proposals aim to isolate dry-year risk but, as covered earlier, this is not a discrete element of optimising supply and managing risk.

Under the proposals, market participants would move from optimising against nodal price expectations only, to also managing against a compliance 'overlay'.

The overlay conveys an administratively determined view of firming need and acceptable responses, and is reinforced by penalties.

The penalties have two parts:

- firming obligations are 'scaled up' so that the parties captured by the arrangements carry full system risk (not just risk associated with the demand they supply)
- failure to meet allocated obligations is penalised at a rate that includes a premium relative to (an administrative assessment of) the cost of supply.

The penalties apply across two horizons – long-term (multiple years ahead) and near-term (within year).

Administrative elements of the regime would include assessing need, allocating obligations, determining acceptable responses, and setting penalties.

It is impossible to quarantine the effects of these planning overlays to dry-year risk, because dry-year firming is not a discrete need met by discrete resources. Rather dry-year variability is one dimension of a dynamic, multi-part optimisation.

Suppliers cannot ignore the administrator's view of need acceptable responses, nor substitute their own view. The administrator's assessments would displace the role that purchaser (including retailer and industrial user) willingness to pay to avoid scarcity currently plays in price formation.

6 Administrative decisions not superior

It is inherently challenging to optimise supply mix over time, and administrative decision-makers do not have better information or incentives to get the balance right.

Optimisation is inherently challenging, including because:

- future demand is uncertain, as is the future cost of supply options
- new supply must be planned and committed well in advance
- an optimal supply mix includes large, long-lived capital-intensive plant (ie, large supply increments)
- gas and carbon markets are subject to inherent uncertainty – part physical and part political
- there are multiple intersecting energy, capacity and transmission risks to manage.

Current arrangements avoid centralising decision-making:

- investors are exposed directly to the consequences of under- or over-supply and hence incentivised to find least-cost solutions
- industrial consumers (and retailers) can contract to manage their risk in way that reflects their willingness to pay to achieve supply security (and price certainty).

A central decision maker is not inherently better placed to identify needs or evaluate solutions.

New Zealand had a history of under- and over-supply before the transition to market-based arrangements. Historical periods of supply stress have included use rolling outages and conservation campaigns, and periods of acute challenge relating to issues such as unit commitment (ie, warming thermal plant or managing river chains in anticipation of morning or evening pinch points).

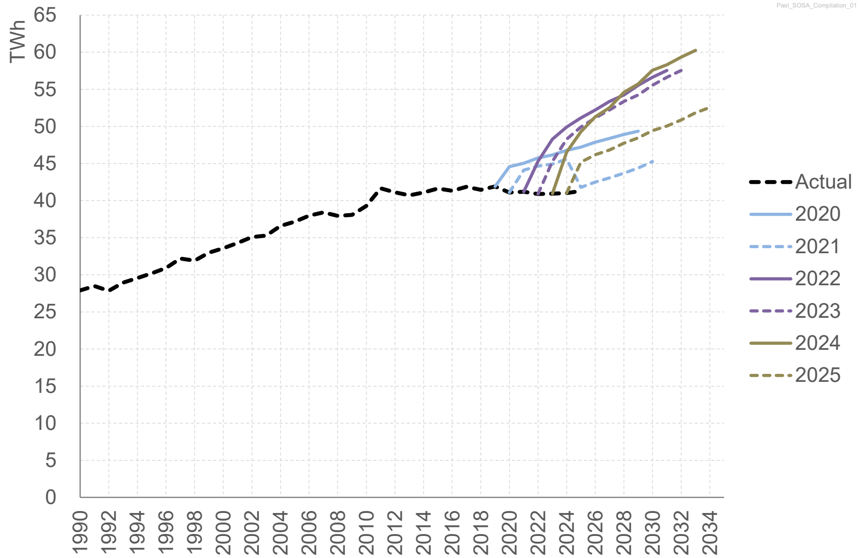
Since market arrangements have been in place, there has been a history of progressively refining arrangements to address issues and improve outcomes.

These refinements have successfully improved performance over time, without reverting to administrative planning.

The proposed arrangements would use the System Operator's Security of Supply Assessment (SOSA) as the basis for determining the need for winter firming.

The historical performance of the SOSA clearly indicates that it is not an infallible, or even superior, basis for determining need.

Figure 9: Past SOSA <u>Low</u> demand projections[7]



[7] The drop in demand in the 2021 SOSA projection was due to the System Operator's base assumption in that year that the Tiwai smelter would exit at the end of 2024. The 'expected' SOSA demand projections proposed to be used in the reliability obligation show even higher growth.

More generally, administrative decision makers:

- have less information – one party cannot access and make better sense of relevant information than the market as a whole
- are vulnerable to under-funding, which can compound the challenge of accessing and analysing information
- unavoidably have institutional incentives to over-procure – ie, because the cost of over-supply is not transparent whereas shortages are interpreted as failure.

Even without a reliability obligation attached to its forecasts, the System Operator is naturally (and appropriately) cautious about supply risks.

However, despite existing institutional incentives, the proposed reliability obligation would not have identified 2024 risks and quantified need correctly:

- thermal stations had contracts with gas suppliers that would have been assessed as compliant, when in practice they appear to have been difficult to enforce
- SOSA scenarios were contemplating a risk of Tiwai exit right up to (and including) in the 2024 update.

In other words, the two key drivers of 2024 outcomes would have posed as much of a challenge for reliability obligation operators as they did for market participants.

As well as determining need, the administrative decision maker has to allocate the assessed shortfall across market participants and assess the acceptability of their planned mitigations.

This is a challenging assignment, and even the best administrative decision maker's assessment would be inherently crude compared to the ability for nodal pricing outcomes, with contractual overlays, to allocate risks and incentivise effective mitigations.

Internationally, efforts to design capacity markets or assign capacity obligations have struggled with these inherent weaknesses of administrative decision making - and compared to dry year firming, capacity is a much more straightforward problem to address.

7 Proposal would distort incentives

The proposals aim to alter gentailer behaviour to produce a net improvement in management of dry-year risk. It is hoped this will result in lower risk and lower prices for consumers.

Our assessment is that while it might achieve the former aim, it will come at the cost of materially *increasing* prices to consumers.

The proposals would charge administrative decision makers with determining:

- how much dry-year firming is needed (determining need)
- who should meet the need (allocating obligations)
- acceptable means of meeting the need (validating solutions)
- penalty for failing to meet obligations (enforcing obligations).

It is proposed that large gentailers would have long-term obligations in their capacity as sellers, and near-term obligations in their capacity as generators. Other market participants would not face any equivalent obligations.

These arrangements would add an overlay to the incentives produced through nodal prices and contracting – where nodal prices signal the real-time cost of meeting demand at each location across New Zealand, and contracts modify how price risks fall between parties.

We consider proposed arrangements would alter incentives, and hence behaviour. However, our expectation is they would increase prices for consumers while altering (rather than mitigating) supply risks.

Key drivers of these outcomes are:

- institutional incentives for administrative decision makers to err on the side of over-estimating need – leading to over-supply
- inherent weakness of addressing dry-year risk and response in isolation – leading to suboptimal supply
- incentives on gentailers to manage their penalty exposure – leading to higher retail and contracting margins
- incentives on fuel suppliers to price up to penalty levels
- reduced access to firming – leading to less independent generation entry.

7.1 Incentive to over-supply

An efficient electricity system will have periods of tight supply or shortage because:

- it becomes progressively more expensive to build supply-side responses to eliminate progressively smaller residual risks – including convergence of extreme low renewable flows (rain, wind, or sun), high demand and compounding fuel or capacity constraints
- some uses of electricity are lower value than others, and would prefer to periodically dial back consumption rather than meet the cost of supply when conditions are tight.

In other words, it is prohibitively expensive to build a level of supply that would eliminate all risk and more realistic to leverage some demand response.

However, the high prices that come with periods of tight supply are unpopular and distressing for some. Consumers and retailers can (and most do) hedge their risk, but some do not and exposed retailers and consumers may plead for political or regulatory relief.

The consultation paper typifies this by diagnosing that 2024 revealed an “intolerable reliability risk” even though the drivers were extreme and the system performed well in terms of sustaining production without needing to call on forced demand curtailment – ie, conditions were well short of calling on the type of official conservation campaign and rolling outage measures provided for in the Code and which have been called on before – including prior to the development of market-based arrangements for electricity supply.

This tension between the economics and the politics of managing electricity supply risks is common globally, and a recurring theme in New Zealand since mid-last century (ie, preceding market-based arrangements).

The proposal would assign Transpower (in its System Operator role) and the Electricity Authority with roles in determining dry-year firming need.

Both parties have insight into the electricity system, and their roles would be designed to provide checks and balances. However:

- it is inherently difficult to estimate an optimal level of cover for future dry-year risk – the need will always be uncertain and arguable
- in being assigned their roles, both parties will assume some accountability for dry-year outcomes – they will carry some of the blame in future when conditions are tight
- neither party will bear the cost of the resources needed to meet the need they identify.

These conditions inevitably create institutional incentives for administrative decision makers to err on the side of over-estimating the need for supply-side cover for dry years.

For example, the 2021 to 2023 SOSA's over-projected demand three years out by an average of ~9,250 GWh. This three-years-out over-projection falls to ~4,425 GWh when looking at the performance of the 2015 to 2023 SOSAs.

Even the one-year out SOSA projections have proven to be significant over-estimates: ~5,000 GWh too high for the last three years' projections, falling to ~3,250 GWh too high for the last ten years' projections.

This may lead to a lower 'risk premium' in forward prices, but it would drive a higher system cost (ie, total cost of resources deployed to supply electricity) and hence higher prices overall – noting that prices need to be high enough to cover the costs of new generation, and increased generation build would:

- move New Zealand up the cost-supply curve of new generation options
- increase the cost of firming if much of the new build were from variable renewable technologies such as wind and solar

For example, if there was a systemic requirement to build more generation than was economically optimal due to SOSA demand over-projections of the scale indicated above (ie, between 3,250 to 9,250 GWh extra), the increase in electricity prices to provide adequate revenue for such extra build would likely be on the order of $11 to $39/MWh – ie, an uplift in excess of 10%.[8]

This would likely manifest in consumer prices and hedge prices (if hedges that are sold are considered part of a gentailer's obligation-captured demand that needs to be covered through supply contracts) through the effect of obligated parties passing on the cost of the penalty through such contracts, rather than wholesale spot prices.

[8] Key assumptions for this estimate: 60% of extra generation build is met by wind. The slope of the cost-supply curve of wind projects is 4.5 $/MWh per GW. Average wind capacity factor = 40%. Base wind LCOE = $100/MWh. Change in capture rate (a measure of firming costs) per 1% increase in proportion of wind on system = 2%.

7.2 Distorted risk management

The proposed arrangements focus on risk associated with dry years (or low hydro inflow sequences) – this is the need the administrators must quantify and large gentailers must cover.

As discussed earlier, the electricity system optimises across all supply risks. This optimisation evolves dynamically as conditions change – including demand, operating conditions (such as fuel availability), and investment conditions (such as technology costs).

Dry year risk is not something to be managed in isolation, and the challenge is not simply to find a replacement for gas-fuelled generation.

The proposals would distort investment and operation by introducing:

- an administrative overlay (identifying need and penalising non-delivery) targeting one aspect of supply risk in isolation. This is likely to cause sub-optimisation – ie, degrading overall system performance by focussing narrowly on one element of performance
- administrative gatekeeping into the process of determining how to manage dry-year risk. This is likely to curb innovation and constrain solutions.

Likely consequences are:

- higher system cost (and hence prices) due to sub-optimisation and solution constraints
- worsening of other (non-dry-year) supply risks.

Additionally, there may be more micro risks associated with the obligation, such as incentives to:

- enter the winter compliance window with higher reservoirs and exit with lower reservoirs – ie, because obligations and penalties alter water values during the compliance window. This would (all things being equal) increase non-winter prices and non-winter fuel risk
- draw water down during the compliance window at less than 18 GWh/day (or more than 18 GWh/day if in a position to be a net supplier of compliant cover). Again, this is because the draw-down rate triggers obligations and this alters water values
- hold back resources that parties may become obligated to purchase under threat of penalty, so as to realise a penalty-linked uplift in price.

Concept has not had time to undertake the analysis to assess the likely scale of effect of skewing incentives to manage one risk (ie, dry-winters) above other risks.

7.3 Dampened retail and contract competition

The current proposals would allocate obligations to large gentailers only, based on their retail and contract positions:

- long-term obligations are proposed to only be allocated to large gentailers in their capacity as retailers – ie, depending on the combined size of their retail and (physical) contract books – and not any other purchasers
- short-term obligations are only allocated to large gentailers in their capacity as generators – ie, depending on how they have committed their generation to serve a retail or contract position – and not any other generators.

These amount to similar things – a gentailer's exposure to dry-year supply obligations (and associated penalties) depends on their sales commitments (ie, their retail and contract positions).

This would play out at two levels:

- collectively, large gentailers must cover system-wide shortfall, including due to non-obligated purchasers not contracting for adequate cover. This means the gentailers' collective obligation is scaled up depending on their aggregate position

- individually, obligations are allocated based on each large gentailer's position.

The net effect is that:

- each non-obligated party has an incentive to under-procure cover – they will save money on hedge premiums yet face no penalty for under-procurement. There will be a limit to this, as under-procurement will increase their earnings at risk. However, if wholesale prices are subdued due to administrator incentives to drive over-procurement of generation (as described in section 7.1), the optimal hedge position will also be reduced.
- each large gentailer:
  - has an increased cost to serve – ie, each customer or contract carries a loading related to increased exposure to supply obligations and penalties
  - has an incentive to manage down its position – ie, serve fewer retail customers and write fewer supply contracts.

All things being equal, this should drive up retail margins above expected wholesale prices, while driving down the market share of the four large gentailer and driving down availability of hedge contracts.

Other retailers (including smaller gentailers) would have a more favourable environment in terms of retail margins and an incentive to grow to a size just below the compliance threshold. In addition, those retailers and large industrials would both have diminished incentive to manage dry year risk.

Each obligated large industrial (ie, as currently proposed, only the Tiwai smelter) faces an increased penalty, but with no ability to manage it through passing on costs to consumers

Concept has developed a simple mathematical model to estimate the likely scale of this effect in terms of the incentive on a large gentailer to reduce their purchaser market share (and the associated obligation) through increasing retail prices.

Key parameters, and initial base assumptions, are:

- initial market shares: Large gentailers: 70%, Small retailers: 5%, Tiwai: 10%, Other large industrials: 15%
- extent to which non-obligated parties (small retailers and other large industrials) under-procure cover: 30%
- extent to which lost market share from a gentailer is picked up by non-obligated retailers: 5 x the original non-obligated retailer's market share
- weather-year-weighted mean wholesale price: \$100/MWh
- contract premium for hedges above weather-year-weighted mean wholesale price: 2%
- retail margin above weather-year-weighted mean wholesale price: 3%
- penalty for under-procurement: \$100/MWh

Using the above assumptions, the likely increase in retail prices (and hedge costs to the extent these are considered part of a gentailer's obligation-covered market share for supply) is ~\$11/MWh.

The Tiwai smelter faces an increase in its costs of ~\$8.5/MWh.

The two most sensitive parameters driving outcomes are:

- the penalty for under-supply – If the penalty for under-supply is reduced to \$50/MWh, the increase in retail prices and Tiwai smelter costs fall largely proportionately, and likewise increase largely proportionately if the penalty is increased to \$200/MWh

- the extent to which non-obligated parties under-procure cover. If the under-procurement is halved, the effect on retail prices and Tiwai costs are also halved.

Other parameters are much more second-order in terms of effects on outcomes.

If the obligation was on all purchasers, ie, including smaller retailers and large industrials, these perverse incentives for non-obligated parties to under-procure cover would disappear, as would the consequent incentives on the large gentailers to reduce their market share by increasing consumer (and hedge) prices.

7.4 Reduced generation entry

As a further flow-on effect, market entry would potentially become more difficult for non-portfolio generators.

Consumers purchasing supply from non-portfolio generators (eg, signing a PPA with a renewables developer) will usually want to cover price risk for their residual demand.

This is more difficult for those potential buyers if:

- non-dry-year firming costs are higher (due to sub-optimisation)
- large gentailers are less willing to expand their positions.

If this translates into less appetite from large consumers to commit to renewables offtake agreements, then this makes market entry more challenging for generators.

The effect will likely be through reduced competitive tension on gentailers to develop new generation, and also potentially through removing good sites from the cost-supply curve of potential projects.

The effect of reduced competitive tension is difficult to estimate. It is potentially the case that having four gentailers competing to develop the next generation 'cab off the rank' will be sufficient competition to ensure that generation is developed promptly.

A simple calculation can estimate the potential scale of effect of the impact on removing projects from the cost-supply curve:

- If 5% of projects are removed and these are evenly distributed across the cost-supply curve, then all other things being equal the slope of the curve will have been increased by 5%
- building on the assumptions set out in the previous example detailed in footnote 8 on page 20, the increase in the cost of supply = $0.1/MWh.

7.5 Higher fuel prices and costs

The likely effect of the long- and short-term obligations would be for fuel costs to flow into increased electricity costs and prices under the proposal:

- as per today, fuel costs (including carbon costs) are a key driver for spot prices – directly, and via water values (ie, the opportunity cost of drawing down hydro reservoirs). As such, fuel cost expectations flow into nodal price risk assessments and influence contract prices and contracting incentives. As seen in 2024, high fuel prices drive high electricity spot prices when renewables flows are low
- over a planning horizon (one to three years) the long-term obligation would provide an overlay – increasing the amount of fuel gentailers (and Tiwai) must demonstrably (to the administrator's satisfaction) plan to access (either directly to fuel their own plant, or indirectly via contracts with others who must fuel their plant) or face a penalty
- over an operational timeframe (within a winter) the short-term obligation adds a further overlay – the gentailers must demonstrate (to the administrator's satisfaction) that they can secure fuel or face a further penalty.

The primary fuels used for generation are:

- coal – sourced by Genesis Energy from domestic and international suppliers at prices that primarily reflect global market dynamics, and on-sold (in effect) to other generators via Huntly Firming Options (and other hedge agreements). Can only be used in the Huntly Rankine units
- gas – today, sourced from domestic production directly, via diversion from other gas uses, or from underground storage (Ahuroa). In future, potentially additionally sourced from international markets via an LNG import terminal using as yet undetermined commercial arrangements
- diesel – sourced from international markets via domestic storage and distribution infrastructure.

Of these fuels, the price paid for gas is the most important for electricity prices, least predictable, most strongly influenced by New Zealand electricity generation dynamics, and most impactful for industrial users (ie, who are the other major consumers of domestic gas).

Absent the proposed reliability obligations, electricity suppliers have responded to expensive and unreliable gas by rapidly reducing their dependence – including by building renewables and improving arrangements for sustaining coal-fired generation.

The proposals would add further pressures to an already challenging fuel procurement picture. Key dynamics are likely to be:

- for a given capacity of thermal plant, a generator covered by the near-term obligation will be more cautious as to their contract position – ie, will sell a lower volume of electricity hedges
- parties covered by the long-term and near-term obligations will also be cautious to procure more fuel:
  - for coal, this translates into higher stockpile costs
  - for diesel, this translates into higher storage costs and more plant
  - for gas, this translates into greater demand from generators to lock-up access to gas. This intensifies market power of domestic gas suppliers (and the LNG terminal operator and any other parties who have already locked up long-term gas supply agreements).

Over a planning horizon, this likely pushes down access to hedges and pushes up firming costs (and hence electricity prices in general) because:

- more fuel is required, pushing up plant costs (for diesel) and storage costs (for coal and diesel)
- gas suppliers are able to increase prices to levels that reflect a complex interplay between obligation penalty rates, the (elevated) cost of coal and diesel alternatives, the willingness for non-generation gas consumers to pay for gas, and the delivered cost of LNG (adjusted for international price uncertainty).

The extra impetus for generators to lock-up access to gas would also impact the price and availability of firm gas supply agreements for industrial gas users, who are already in a difficult position.

The near-term obligation will also likely result in hydro operators being more cautious about their reservoir release decisions, through including the cost of the penalty to their water value curves.

In short:

- Generators already have strong financial incentives to procure sufficient fuel and manage their hydro reservoirs to cover the supply contracts they have entered into: if they run short during a period of scarcity they will face high costs from needing to cover their shortfall by purchasing from the spot market.

- The obligations, particularly the near-term obligation, will simply add to the costs of generators insufficiently procuring fuel or releasing their hydro reservoirs too soon. The effect of this will be to reduce the amount a generator is willing to sell under contract and increase the amount of fuel they procure / hold in stock, to the point where the risk-weighted returns are the same as they would be from selling a greater amount without needing to hold so much fuel in stock in a market where there was not this additional penalty.

  This may indeed be the point of the near-term obligation. However, it should be appreciated that this is not costless and, like the other aspects of the obligation, will certainly have the effect of increasing average prices, even though it may reduce prices in the most extreme dry years.

To help get a feel for the potential scale of this cost increase, Concept ran its electricity module within its ENZ model with thermal generators facing 5% higher fuel costs. For the early years of the projection (≤5 years after the price increase came into effect) this resulted in electricity wholesale prices being ~2.5% higher. The price increase was a lot more muted (~0.1% higher) for the longer period as the system was:

a) able to equilibrate to a slightly higher level of renewable build to displace the more expensive thermals with the LRMC of renewables being only marginally higher
b) faced with slightly reduced electricity demand as the higher price of electricity reduced the rate of electrification, thereby bringing the system back into a similar level of balance

7.6 Impacts are additive

The cost impacts identified above are additive:

- conservative dry-year margin increases system cost, and hence prices
- sub-optimisation and constrained innovation further increase system cost (and hence prices) and heighten other risks
- dampened retail and contract competition due to the perverse incentives on gentailers from being the only obligated parties expand margins
- effective fuel price penalties from the near-term obligation will increase conservatism in fuel procurement and reservoir management, pushing New Zealand up the fuel cost-supply curve
- reduced generation entry dampens pressure to take on the risk of erring on the side of earlier system expansion.

It is not the case that reducing dry-year risk simply flows through to lower prices due to a lower risk premium. This would be true if risk reduction were costless, but it is not – and higher system cost must ultimately flow through to higher prices, even if this is through consumer prices rather than wholesale spot prices.

Overall, under the current proposals, we estimate the increase in the average wholesale component of prices to consumers will range between $15 to $50/MWh.

That said, the proposals will almost certainly radically reduce the wholesale spot prices during dry years. However, it is not clear that it is worth increasing the average wholesale component of prices to consumers by ~13% to 42% to achieve this – particularly when consumers already have the ability to protect themselves from the impacts of high prices during dry years through contracting forward with suppliers.

8 Current arrangements could be enhanced

Although the electricity system performed relatively well in 2024, there is scope for improvement. In particular, 2024 highlighted weaknesses in:

- the quality of gas market information
- purchaser incentives to manage their price exposure.

Looking ahead, there may also be residual challenges around the ability for participants to form the full range of contracts needed to efficiently manage risk and support investment.

Enhancing current arrangements would be more effective, less disruptive, and carry less risk than shifting planning and risk management into a new administrative regime. As covered above, risks include:

- administrative planners are less well placed and less well incentivised to optimise the electricity system than participants
- focussing on dry-year risk in isolation promotes sub-optimisation, driving higher total costs and risk
- the metrics and penalties used in the regime will distort behaviour, likely driving up system cost and retail margins, while making independent generation entry more difficult.

In addition, making substantial changes today to solve yesterday's problem risks worsening tomorrow's problems – including the need to continue rapidly expanding supply to match anticipated demand growth.

Accordingly, we recommend focussing on three key pillars of well-functioning markets. In this case:

- information – improved information regarding risks stemming from the gas market
- incentives – improvements to the stress testing regime to further reinforce purchaser incentives
- ability – improved access to the full range of contracts needed to support efficient investment and risk management.

8.1 Gas market information

As set out in section 2, two key dislocation risks loomed as 2024 approached:

- Tiwai – uncertainty as to whether the aluminium smelter (responsible for ~12% of New Zealand demand) would exit
- gas production – uncertainty as to the success of drilling to sustain gas production.

Market participants were well aware of potential Tiwai closure, which was increasing the downside risk of adding supply.

However, participants were less aware of the potential for gas supply to fall away sharply, and of how this would impact gas users (including generators).

Ultimately, these risks crystalised in compounding directions to produce the 2024 hinge year:

- Tiwai struck long-term contracts in mid-2024 – this firmed up the demand outlook and incentives to add generation. Tiwai's contracts also included new demand response arrangements, adding to the suite of risk management resources
- gas producers collectively experienced poor drilling campaigns and under-performance of existing wells, drastically tightening the supply outlook. This caused a near-term scramble for supply and crystalised the need to further build out renewables.

Generators were ultimately able to secure gas by late 2024 through contracting with Methanex. Methanex has long played a role as a major 'swing' consumer of gas, but as production has dwindled it now needs to pause production altogether to free-up gas for higher-value uses (ie, dry-year electricity production).

Gas market weaknesses were key drivers of 2024 electricity market outcomes in two ways:

- system balance – the electricity system was not optimised for reduced gas production. Had gas risks been clearer, this would have strengthened incentives ahead of 2024 to bring forward more renewable generation
- fuel – reallocating scarce gas from methanol production to electricity generation during 2024 was slow, disruptive and expensive.

Post-2024, gas production risks are both clearer and less material – ie, a major downside risk has crystallised now and the residual risk is smaller. Thermal generators also appear to have now secured gas supply agreements to cover their requirements.

However, there would still be benefit in enhancing gas market arrangements. Priorities should be to improve:

- production information – more timely, frequent, and complete public disclosures, including producer self-assessments of downside risk
- price transparency – better visibility of gas contract prices to support price discovery and enable better planning and dynamic trading to reallocate scarce gas to its highest value use.

As well as assisting thermal generators, these improvements would assist:

- non-thermal generators and electricity consumers – the cost of gas-fired generation is a key input for determining the value of other supply options (including demand response)
- other gas consumers – while generators may have secured supply for their own needs, the supply and pricing outlook remains challenging and uncertain for other gas consumers.

8.2 Purchaser incentives

When supply is tight in any market, prices rise until supply and demand balance. The level at which prices settle should reflect both:

- supply – the marginal cost of supply-side resources – this drives prices up as increasingly expensive resources are used to meet demand
- non-supply – demand-side response – as the price increases it will exceed the willingness to pay for some consumers.

If both of these factors play their part in electricity price discovery, prices should at times rise to a level above the short-run cost of generation and will cover the capital costs needed to deliver an optimal system.

As such, high prices at times of system stress are a feature, not a bug – they play an essential role in enabling an optimally reliable system.

While nodal prices play this role in real time, most producers and consumers prefer to insulate themselves from the cashflow impacts of volatile pricing – consumers prefer lower prices at times of system stress and producers prefer more predictable revenue.

Most consumers insulate themselves by purchasing from retailers, who in turn take on and manage the risk through some mix of asset ownership, contracting, and self-insurance. The cost of this risk management is reflected in retail prices.

Some large consumers adopt more sophisticated approaches – managing their own mix of assets, contracts and self-insurance.

Others contract with retailers, though tend to negotiate pricing through tenders rather than accessing mass market retail plans.

In this way, contracts modify how nodal price risks are allocated and play an important role in guiding and supporting investment. Contracts can:

- protect consumers from the stress of high prices, while preserving incentives to curtail demand[9]
- produce cashflow profiles and price signals that better support investment, especially for infrequently needed generation resources.

This process can break down if consumer willingness to pay is not properly reflected in price discovery and signalling. To address this, market arrangements have evolved over time to include:

- scarcity pricing – if demand is curtailed, administered scarcity prices are used to reflect the value of unmet demand. This ensures prices do not collapse when demand is curtailed, because this would under-signal the value of additional supply
- customer compensation payments – if an official conservation campaign is used to encourage consumers to reduce demand during a fuel shortage, retailers must make payments to their consumers. This ensures retailers cannot treat such campaigns as a free resource, because this would encourage over-reliance
- stress test disclosures – wholesale market purchasers (including retailers and large consumers) are required to prepare “spot price risk disclosures” indicating their financial exposure to specified stress test scenarios. This ensures purchasers must assess their risk, and aims to make it harder for purchasers to under-insure and then appeal for political or regulatory relief.

All these measures were developed as responses to periods of system stress, and aim to address unique features of electricity markets including:

- impracticality of selectively rationing supply to consumers based on willingness to pay. This means there is an incentive for purchasers to free-ride, rather than cover the full cost of secure supply
- public and political interest and willingness to intervene when supply is tight. This means there is a track record of under-insured parties gaining relief through regulatory and political pleading.

On the whole, these measures appear to have been successful at improving management of supply risks (including dry-years).[10] However, they do require upkeep and there may be scope for further improvement.

The Authority has refined each of the measures over time, including through implementation of scarcity values into real time pricing, a 2023 update to the minimum value for customer compensation payments, and regular reviews of stress test scenarios.

We understand the Authority intends to review the ‘value of lost load’, which would aim to ensure scarcity prices are well calibrated into the future. This is useful in an evolving system – including as

9 A consumer buying hedges on a three-year rolling basis could have secured a price below $150 per MWh for the 2024 calendar year, and would have had an opportunity to gain whenever spot prices were above that level. For some consumers, reducing electricity demand would have been a more profitable option at times than using electricity (a win-win outcome).

10 This is illustrated by market research carried out for the Electricity Authority comparing 2008, 2012 and 2017. See: Insights Dashboard: Dry Winters 2008-2017

uses of electricity change and consumer ability to self-insure (with batteries) improves.

Another important area of focus is continued efforts to improve how demand-side flexibility is integrated into network pricing, system operation and wholesale market arrangements. Maintaining and enhancing use of hot water flexibility, accessing EV charging flexibility and expanding industrial flexibility all helps lower the need for supply-side flexibility. As well as reducing supply costs directly, this frees hydro flexibility to manage dry-year risk.

We think there would also be value in reconsidering whether stress test disclosures should be fully anonymised.

The aims of the stress test are both to strengthen awareness within firms that have spot price exposure and to address the 'moral hazard' that arises if purchasers can mitigate the consequences of under-insuring through political and regulatory pleading.

Effectiveness at promoting this second aim would be improved if disclosures were not fully anonymised. Disclosures to the Authority include sensitive financial information that is appropriate to protect. However, we think a better balance could be struck by publishing high-level metrics for each firm to indicate their level of insurance against high spot prices.

Other areas for enhancing the stress test regime could include addressing:

- renewal and roll-forward risks – ie, how far into the future purchasers have covered their risk
- large users with retail contracts that expose them to spot price risk indirectly – eg, through retail price components linked to spot prices
- constructing scenarios around dislocation risks – such as a sudden change in gas or carbon prices, or arrival of a large new load.

Finally, we note another potential source of distress is where large consumers re-tender for retail contracts in the midst of a period of tight supply. Mitigations are to re-tender well ahead of need (and also not in winter) or adopt a more sophisticated approach to managing price risk, such as through purchasing hedges on a rolling multi-year basis.

In this case, we think consumer education may be a better fit than extending stress testing – including retailers assisting large consumers by encouraging early re-tendering.

8.3 Ability to contract

For markets to work effectively, parties need to be able to manage their risks through contracting.

Contracts enable purchasers to protect themselves from the cashflow impact of high prices and enable suppliers to convert uncertain potential revenue streams into predictable cashflows.

Spot prices vary by location, across each day, week and year, and over time. In each case, prices reflect the ever-shifting balance of supply and demand.

As the New Zealand electricity system evolves, notable drivers of pricing volatility will include:

- increasing periods of very low prices when high solar and wind production coincide, sending a signal to store energy in hydro reservoirs, batteries and hot water cylinders
- continuation of occasional runs of elevated prices when hydro inflows and levels are low, sending a signal to conserve storage and use higher-cost fuels
- periods of elevated or suppressed prices when system balance swings between surplus and tightness as new generation is brought on to meet growing demand

- shorter periods of elevated winter prices when multi-day lulls in solar and wind (dunkelflauten) draw down battery and hydro storage
- continuation of occasional price spikes when unexpected failures (of fuel, generation or transmission) interrupt supply.

The profile of spot price risk drives the mix of contracts sought by consumers and producers, the value of those contracts, uncertainty as to their value, and ultimately the price and volume at which they're traded.

A key requirement for efficient contracting is for buyers and sellers to be able to agree on price, which is easiest when standard contracts are traded through an exchange platform that provides liquidity and price transparency.

This is well established for baseload futures, and the Electricity Authority has been working with the sector to put arrangements in place for 'super-peak' products. There has been welcome progress since 2024 that should drive significant benefits – for parties who transact hedge contracts directly, and for retail consumers via retail competition and improved ability to test the reasonableness of retail pricing.

However, exchange-traded contracts cannot meet all contracting needs so over-the-counter contracts will always play an important role too.

Three areas of particular interest for such contracts are:

- thermal generation – thermal generators face significant revenue uncertainty. They may experience multiple 'wet' years in a row or may find prices suppressed when the system is tight. In addition, whether thermal generation is needed longer-term depends on how it competes with other technology costs and how carbon and fuel costs and availability evolve
- renewable generation – renewable generation has high up-front costs and low operating costs, so the cost of financing is a major driver of financial performance. Renewable generation also risks being out-of-the-money longer term if technology costs fall or the system is over-supplied
- large generation and demand increments – in the same way Tiwai exit presented a major dislocation risk leading into 2024, large new demands (such as datacentres) or generation developments can materially shift overall supply balance – creating extended periods of over- or under-supply.

For thermal generation, arrangements such as swaptions and the Huntly Firming Options can meet the needs of buyers and sellers. They produce a secure revenue stream for generators while protecting buyers from extended high price periods.

Willingness of buyers to purchase option contracts strongly depends on institutional arrangements credibly reinforcing that it is prudent to insure against the risk of efficiently high prices at times of scarcity, and that appealing for political or regulatory relief will not result in intervention if it is apparent that the buyers were aware of the scale of risk but chose not to contract.

For renewable generation, key mechanisms for managing revenue risk include:

- vertical integration – building a retail book to complement generation creates a natural hedge. This has been a successful approach for incumbent portfolio generators, and has been applied successfully by at least one entrant solar generator
- power purchase agreements (PPAs) – some purchasers have sufficiently large electricity needs and good enough credit

strength to sign long-term (eg, 15 year) agreements to purchase the output from a renewable development.[11]

There is an inherent scarcity of end users willing and able to support large long-term PPAs, and vertical integration is not an attractive model for all potential developers. In addition, there are underlying risks that:

- some new developments will be 'out-of-the-money' and fundamentally unable to recover their up-front cost
- the PPA buyer may not have a long-term need for the contracted volume of energy. This may be uncertain for end user and retail purchasers alike.

The New Zealand government is exploring PPAs for its own energy needs, which could usefully expand the pool of quality buyers.

Other jurisdictions have set up various mechanisms to socialise elements of PPA risk. This may seem attractive, on the basis that:

- supporting independent generator entry counters concerns that weak competitive pressure may allow incumbents to 'slow walk' generation expansion
- with demand widely expected to grow, the downside risk of stimulating over-expansion may appear lower than the risk of under-expansion of new generation.

However, over-expansion is not costless, and it is not clear investment could rationally have responded any more quickly than it has to the dislocation risks leading into 2024 – a huge amount of generation has since been added and prices have rapidly returned to levels that reflect the cost of entry.

This leaves dislocation risks – ie, the challenge of maintaining system balance when there are step changes in demand or supply (or in fuel costs or availability). These sit atop the challenge of expanding supply at a rate that broadly keeps up with year-to-year demand growth (and changes in fuel or capacity).

There are several mechanisms that provide some information to manage this risk, including:

- within project commissioning timeframes (6 to 12 months ahead) the Electricity Authority publishes useful monthly updates from the System Operator on target commissioning dates for large assets (including demand, supply and storage)[12]
- there are long-standing arrangements for coordinating planned plant (and transmission) outages up to a year ahead
- the Authority publishes generation development pipeline information covering a longer planning horizon
- listed companies with continuous disclosure obligations generally provide clear information on planned investments and major plant retirements or changes
- where large users opt to use PPAs, commencement provisions play a useful role in linking generation expansion to a specific demand increment.

We consider it would be useful to explore whether these mechanisms could be expanded to improve visibility of large demand increments over a planning horizon relevant to final investment decisions for generation plan (ie, 1-3 years).

[11] Since PPA output won't match an end user's needs, they will have residual demand for which they may want retail supply (sleeving) or hedge contracts (financial firming). PPAs have also been purchased by gentailers, who generally have good credit strength and integrate the new generation into their wider portfolios.

[12] See the 'Supporting asset-owner activity' section of the monthly reports at: System Operator | Electricity Authority

Going further, two options that could potentially address the impacts of dislocation risks could be:

- a ‘bring your own energy’ obligation for very large demand increments
- guardrails on termination timeframes for supply contracts for very large demand increments.

The rationale for such measures would be that the actions of large increments have a material impacts on the wider system, and consumers generally.

Appendices

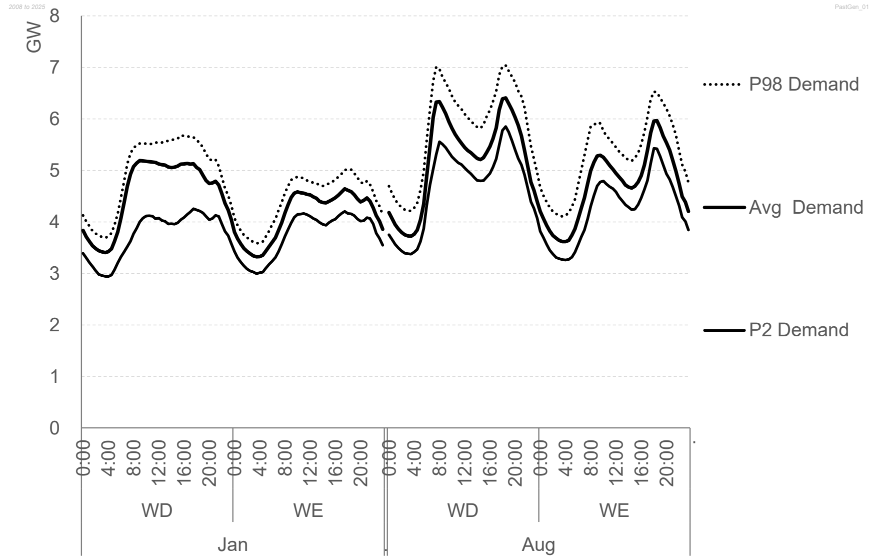
A Drivers of the need for flexible resources

A.1. Historical drivers and providers of flexibility

A.1.1. Demand variation is a key driver of the need for flexibility

As illustrated in Figure 10 there is significant variation in demand on a within-day, within-week, and within-year basis.

Figure 10: Average pattern of demand from 2008 to 2025[13]

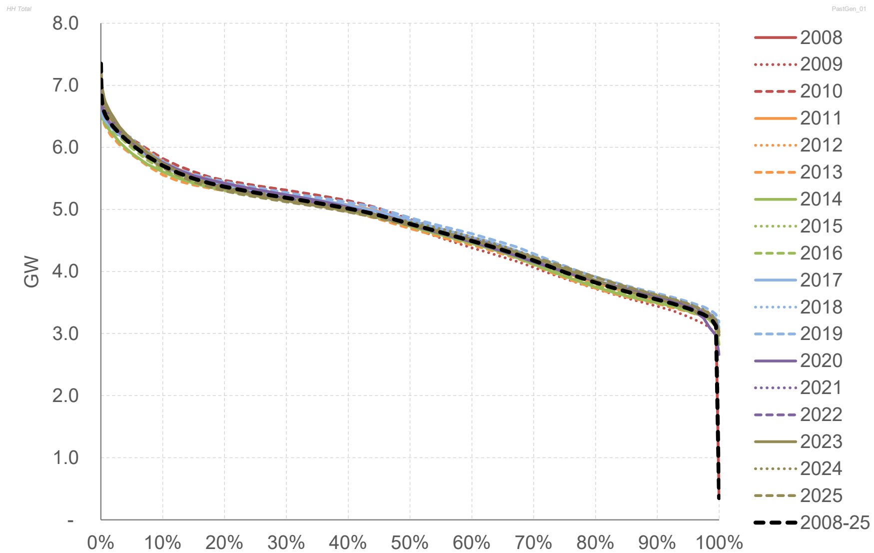


Some of this variation is predictable, following the regular within-day and within-week patterns of human activity and the regular within-year variation in demand for heating and lighting.

However, Figure 10 shows that for any given time of day and year there can be material variation in the amount of demand that occurs – as indicated by the P98 and P2 lines (being the 98th and 2nd percentile values, respectively). This is significantly due to variations in weather (eg, colder or hotter weather altering heating /cooling demand), but can also be due to changes in consumption from major industrial consumers.

Another way of showing this variation in demand is on a duration curve basis – sorting every half-hour in descending order. This is shown in Figure 11.

Figure 11: Duration curve of half-hourly demand for generation



13 The years 2008 to 2025 have been chosen as total annual demand was largely flat during this period, allowing for broadly like-for-like comparisons of how generation has met demand between these years.

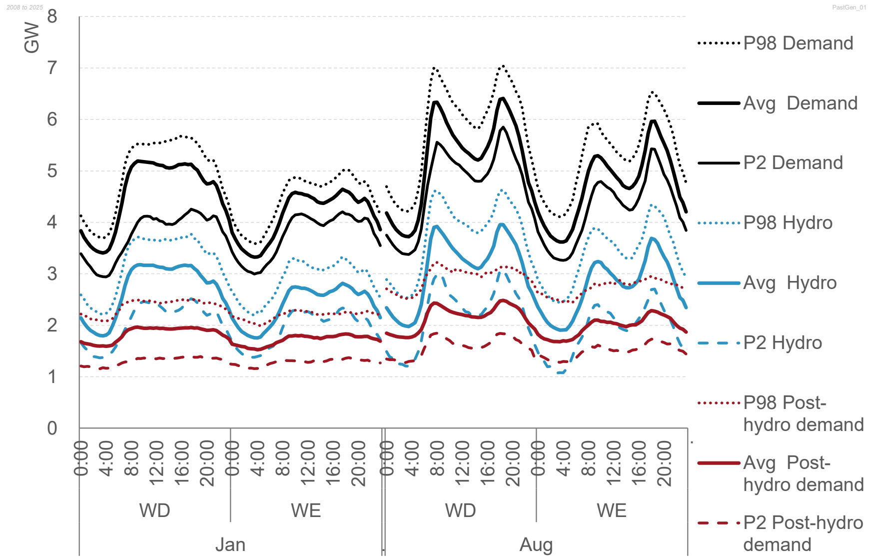
This variation in demand gives rise to a need for some supply to operate flexibly by increasing output at times of high demand and decreasing at times of low demand. Figure 11 shows that over the period 2008 to 2025, we have needed ~3 GW of generation operating 24/7 (also known as 'baseload'), and a further ~3.5 GW of generation operating some of the time. Overall, the amount of flexible generation required to meet demand variation is ~12 TWh – being the area under the curve above the 3 GW (ie, baseload) level.

A.1.2. Hydro generation both provides, and causes a need for, flexibility resources

The storage lakes in New Zealand's hydro schemes meet much of this need for flexibility. By storing water at times of low demand, and releasing to generate at times of high demand, they significantly reduce the need for other types of generation to operate flexibly.

The typical pattern of operation of hydro stations and the consequent effect on the post-hydro residual demand is shown in Figure 12 below.

Figure 12: Average pattern of demand, hydro generation, and post-hydro demand from 2008 to 2025

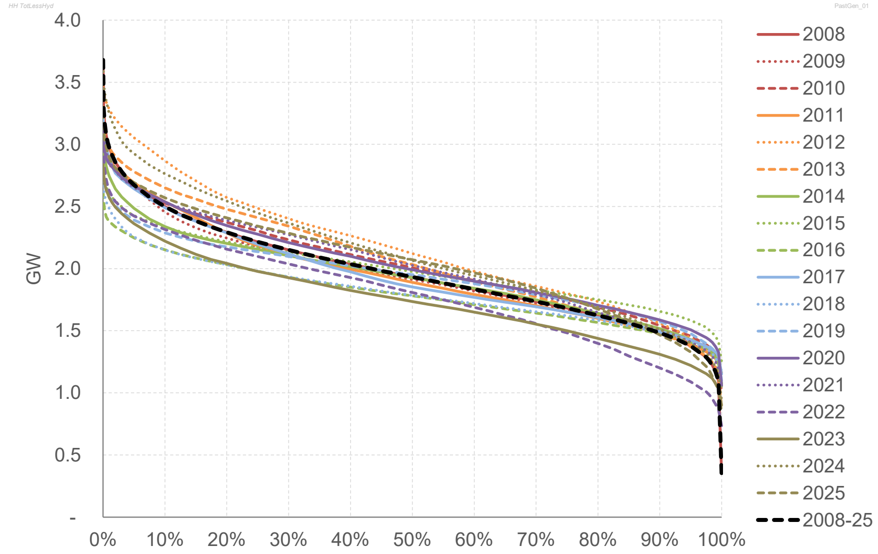


As can be seen, hydro stations provide a significant amount of the need for within-day flexibility as illustrated by the post-hydro demand curves being significantly flatter than the demand curves. They also provide within-week and within-year flexibility, as illustrated by the post-hydro WD / WE variation being reduced and the Jan / Aug variation.

However, there can be significant year-to-year variation in inflows into the hydro schemes. This is illustrated in Figure 13 which shows that there is a greater variation between years in post-hydro demand than there is variation between underlying demand. This means hydro itself *creates* a need for other flexible resources to balance supply over a longer timescale.

Looking at the overall duration curve across years, it can be seen that there is now a need for ~1 GW of post-hydro generation to operate baseload, and a further 2.7 GW to operate flexibly, and an overall need for ~ 6.2 TWh of flexible generation.

Figure 13: Post-hydro residual demand curves for 2008-2025

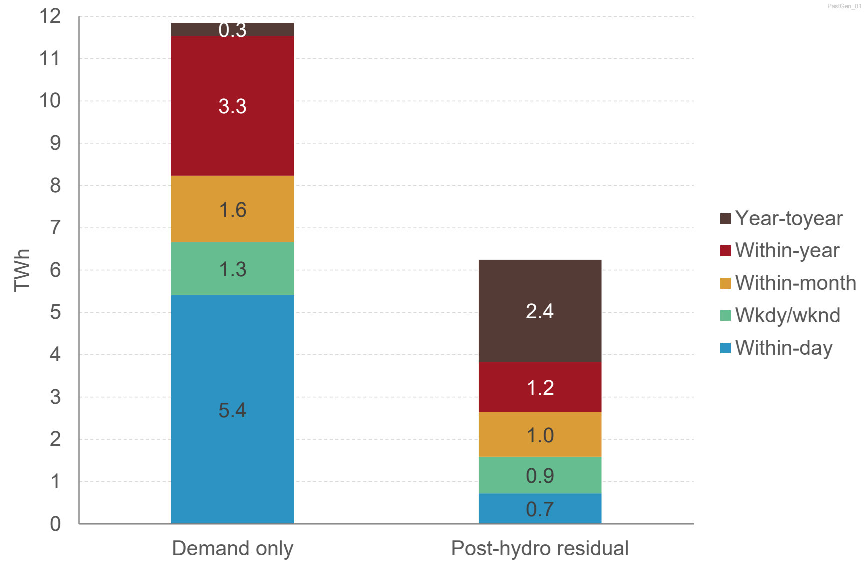


To-date, the ‘dry-year problem’ from the variation in hydro inflows has proven to be the biggest challenge in providing flexibility resources in New Zealand. This is due to:

- The significant year-to-year variation in the extent of need
- The long duration of shortage periods which limits the type of resource that can meet shortage

The overall extent to which the hydro schemes both contribute to and cause the need for flexibility over different timeframes is illustrated in Figure 14.

Figure 14: Historical flexibility requirements from 2000 to 2025[14]



As the historical series used for this analysis is only the 26 years from 2000 to 2025, the true range of hydro variability outcomes is likely to be even greater – potentially by another ~1 TWh.

[14] The apportionment of the need for flexibility in different timeframes is achieved by first creating a duration curve of historical demand on a half-hourly timeframe. The area of the curve which is above the ‘baseload’ capacity is deemed the amount of flexible generation required. In Figure 11 the total need for flexibility to meet all demand variation is ~12 TWh. Then a second duration curve is created of daily demands. The difference in the amount of flexible generation required on this basis compared to the half-hourly duration curve is equivalent to the amount of flexibility required to meet within-day variations in demand = 5.4 TWh in Figure 14 for demand only. This is then repeated for a duration curve of weekly demand to create the within-week flexibility requirement, and so on. This is repeated using duration curves of historical demand less hydro generation, to calculate the post-hydro residual demand requirements.

A.1.3. Variability and uncertainty in other factors also create a need for flexible resources

In addition to the weather-driven variability detailed above, there are other factors that have given rise to a need for some resources to operate flexibly:

- unexpected failures of supply assets (generation stations, fuel supply), especially extended outages
- unanticipated changes in economic supply/demand balance due to
  - generation build failing to anticipate changes in demand or facing unanticipated delays in development
  - unanticipated changes in fuel supply costs. Either due to external factors (eg, gas field failures or the US-Israel-Iran war) or government policy factors (eg, policy actions significantly changing carbon prices)

A.1.4. Summary of drivers of need for flexibility

Table 1, summarises the causes of variability that give rise to the need for flexibility resources, differentiating by different dimensions according to whether:

- The variation is predictable or unpredictable
- The cause is due to variations in weather or some other factor.

Table 1: Dimensions of demand/supply variability

		Supply	Demand
Predictable / Regular	Weather	• typical diurnal and seasonal variations in 'flows' of sunshine, rainfall/snow-melt, and wind	• typical seasonal variations in temperature and daylight, and consequent variations in space heating and cooling, water heating, and lighting
	Other		• following the regular patterns of human activity (within-day and within-week (plus holidays))
Unpredictable	Weather	• variations in the amount of renewable flow that would be expected at a given time of day or year	• temperature variations causing heating/cooling demand to be higher or lower than typical for that time of day or year
	Other short term	• unexpected failure of: - generation assets (renewable or thermal) - fuel supply assets (eg, gas fields or pipelines)	
	Other long term	• government policy (eg, on carbon prices) • gas supply • generation build being delayed	• rate and scale of demand growth • potential step changes in industrial demand following unanticipated large site closures

In considering the relative suitability of different options to provide flexibility, it is critical to appreciate that there are different types of flexibility duty required, characterised by the following key dimensions:

- ***The average proportion of a year an asset will be required.*** This ranges from low-capacity-factor operation (mostly not providing supply, except at times of extreme scarcity) to high-capacity-factor operation (mostly providing supply, except at times of extreme surplus).
- ***The periodicity of requirement***. This ranges from: diurnal (a typical on/off pattern of need on a within-day or within-week basis), seasonal (on/off between summer and winter), through to year-to-year (variation between years)
- ***The duration of operation when needed***, ranging from hours through to months.

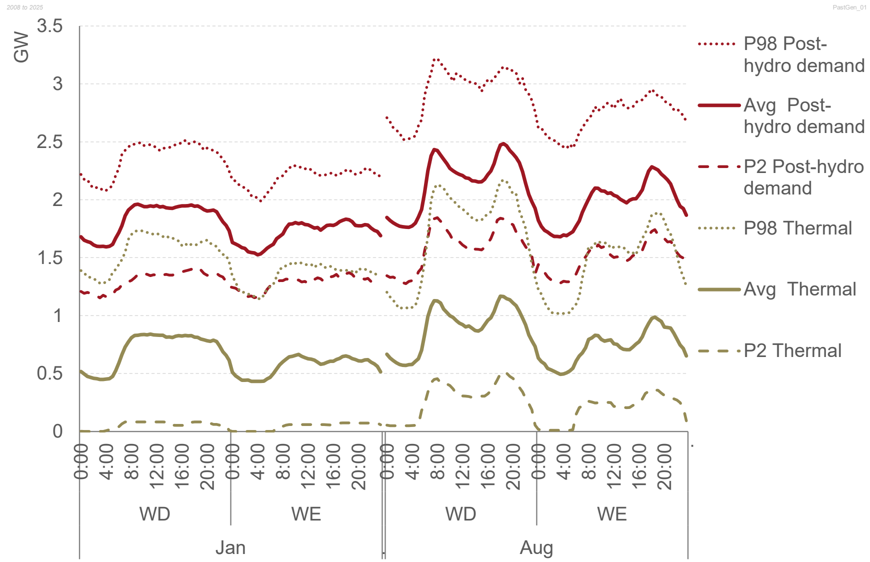
There is no strict delineation of flexibility duties into particular categories, but the above dimensions mean there is a spectrum of need ranging from

- regular short-duration flex (eg, a daily need to increase/decrease output for durations of no more than a few hours), through to
- irregular long-duration flex (eg, a need for some assets to operate only once every ‘x’ years but, when needed, to do so for a duration of many weeks or months). As set out in more detail later, this flex need is relatively unique to New Zealand as it is due to major yearly variations in hydro output.

A.1.5. Thermal generation has been the principal provider of flexibility resources to-date

To date, the vast majority of post-hydro flexibility duty has been performed by thermal stations – the combined fleet of combined-cycle gas turbines (CCGTs), Rankine stations, and open-cycle gas turbines (OCGTs). As illustrated by Figure 15, these have operated flexibly on a within-day, within-week, within-year, and year-to-year basis.

Figure 15: Average pattern of post-hydro demand and thermal generation from 2008 to 2025



The fact that there is a wider range between the P98 and P2 values for thermal than for post-hydro generation in Figure 15 is because during the 2008 to 2025 period there was development of additional renewable generation at a rate greater than demand growth during that period. As a consequence, thermal generation was progressively pushed out from baseload duties. This pattern of displacement is illustrated in Figure 16 and Figure 17 below. (Note:

'Solar' in these charts only includes those solar farms big enough to report their generation data to the market operator. As such, the charts exclude rooftop solar.)

Figure 16: 12-month rolling total grid generation - area graph

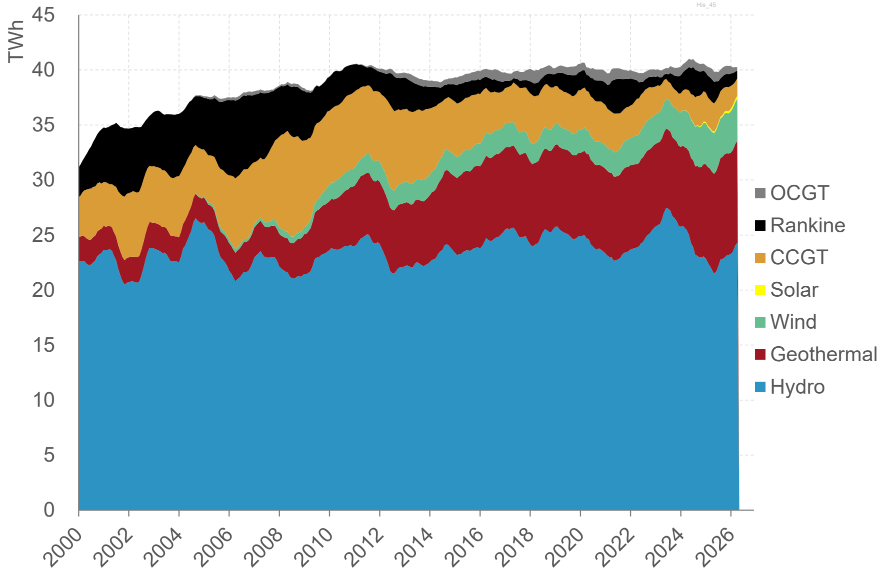


Figure 17: 12-month rolling total generation - line graph

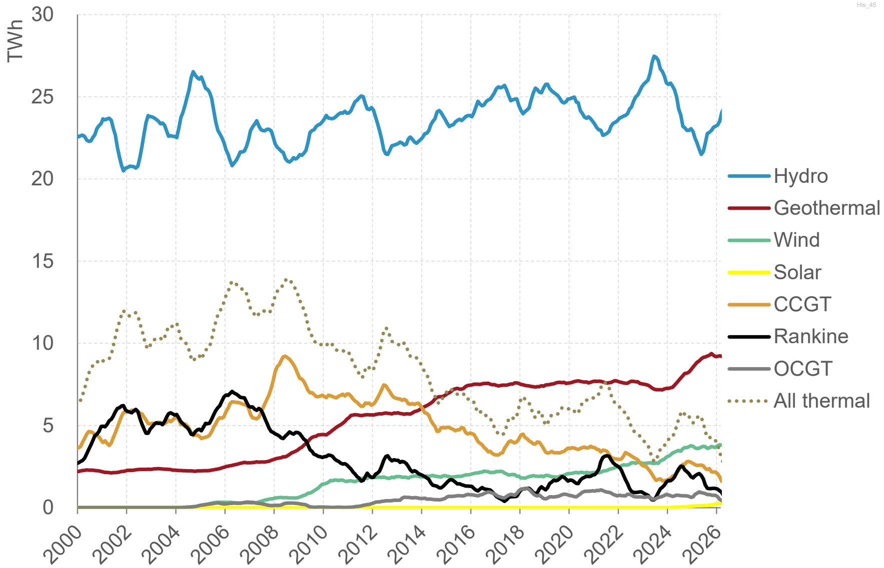
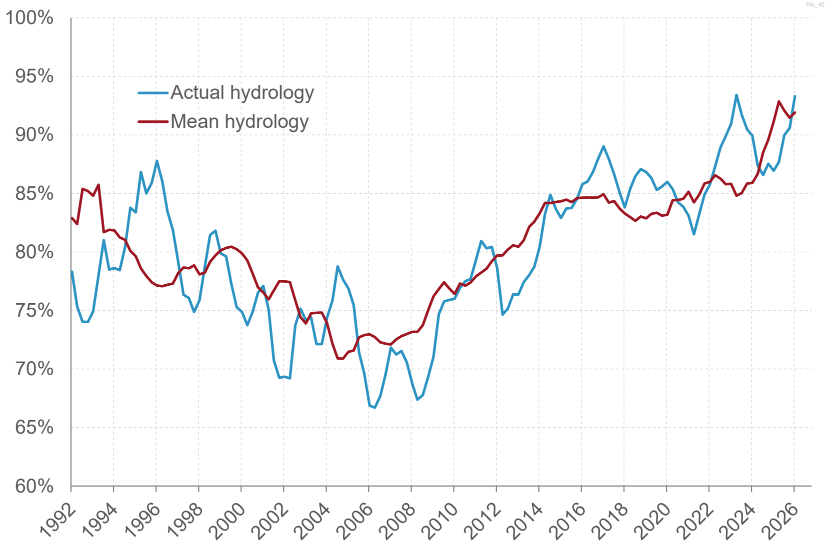


Figure 18 below further illustrates this displacement, by showing how the percentage of generation from renewables has increased, on a mean hydrology basis, from a low of ~70.5% to reach ~91.5% by March 2026.

Figure 18: Percentage generation (excl. cogen) from renewables - rolling 4-quarter basis



(Note: The mean hydrology calculation assumes that if hydro generation had been at mean levels, the difference between actual hydro generation would have been balanced by changing thermal generation. This approach is sound until 2025. However, going forward, such a calculation will need to take account of any spill that has occurred – something that will increasingly be hard to do when the 'spill' can be the feathering of wind turbines.)

The scale of renewable development has reached a point where thermal generation is now completely displaced from baseload duties. This can be seen in Figure 19 and Figure 20, comparing the pattern of generation in 2013 versus 2025.

Figure 19: Daily generation for 2013

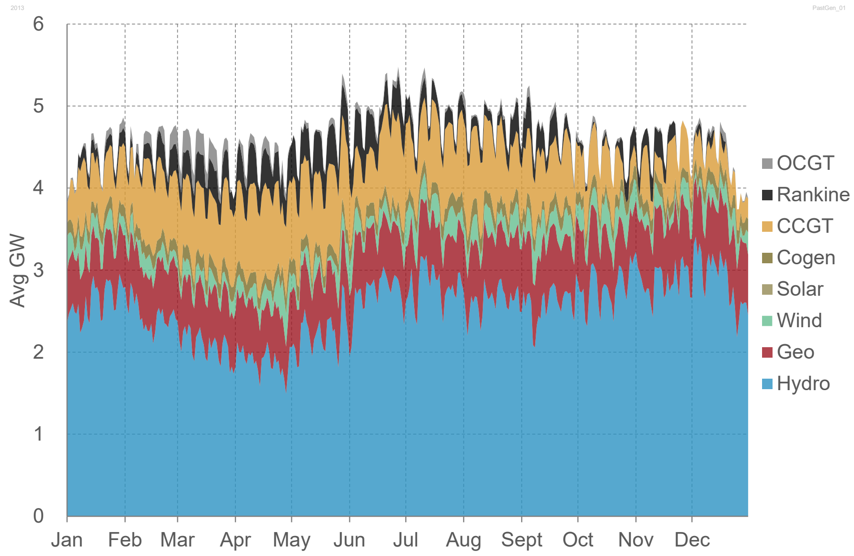
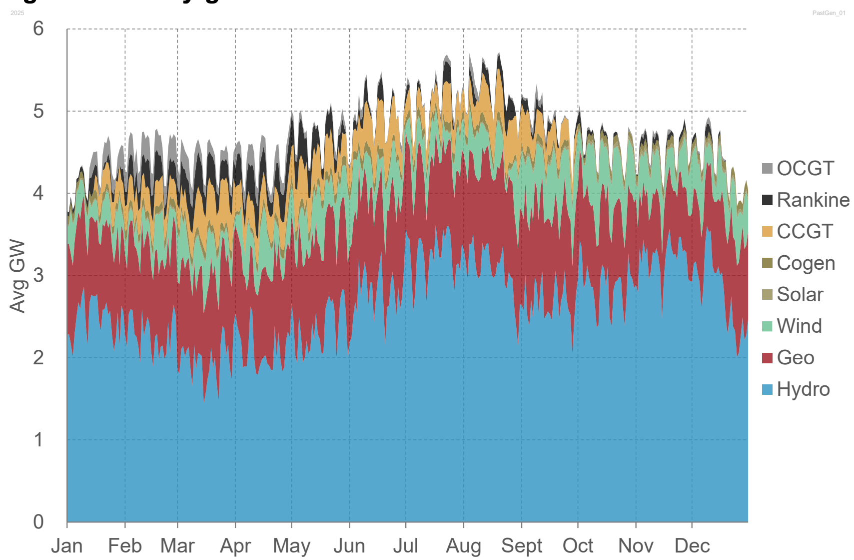


Figure 20: Daily generation for 2025



Thus, in 2013 there was always some thermal generation operating – including always a CCGT. However, in 2025 the last three months had almost no thermal generation, with the last few weeks of December having none at all. During these last few weeks, the scale of renewable flows was such that not only was no thermal generation required, but some potential renewable generation was 'spilled'. Either literally spilled in the case of water going over the spillways of hydro dams, or through wind farms feathering their turbines instead of generating.

Other forms of flexibility resource have and could be used

Hydro reservoirs and thermal stations are just two of the options among a greater variety of different resources that have the potential to provide flexibility duties. These other options include:

- ***Over-build of renewables***, ie, building renewable capacity that will be surplus to requirements for some of the time (leading to spill) but which will be closer to being adequate during periods of renewable scarcity (eg, dry year events). In effect, spill becomes the flexibility resource.
- ***'Pure' storage options*** (as distinct to storing thermal fuel). This involves using electricity at times of surplus to convert into another energy storage medium which can be used at times of electricity scarcity. Options include batteries, EVs, hot water, pumped hydro, other gravity storage, and industrial thermal heat.
- ***Demand curtailment*** at times of scarcity, ranging from large industrial consumers (eg, Tiwai aluminium smelter) through to residential & commercial.
- ***Dual-fuel industrial process heat*** (eg, coal/electric, diesel/electric).

These different options have varying degrees of suitability to meet the different flexibility duties due to variations in financial structure (the mix of fixed versus variable costs) and physical characteristics (eg, the degree of controllability, or the ratio between the size of a storage 'tank' versus storage 'tap').

As the system transitions to a high % of renewables, not only is the nature and scale of flexibility requirements likely to change, but the optimal mix of resources to meet these requirements is also likely to change.

Box 1: Demand curtailment is not a form of de-industrialisation!

It is often perceived that curtailing demand at times of scarcity is a market failure. However, this is definitely not the case. Gold-plating the system so that there is never any shortage periods would be extremely expensive. At times, it would be most cost-effective for consumers who derive lower-value demand from consuming electricity to curtail their demand, rather than build expensive infrequently-required supply assets.

If these consumers have contracted forward for their supply in a way that rewards them for not consuming, they will get *greater value* from not consuming than consuming – a win-win. This is not de-industrialisation. The problem arises if consumers haven't contracted forward for their supply.

A.2. How is the need for flexibility changing?

A.2.1. Renewable development is <u>reducing</u> the need for dry year thermal generation – but creating new flexibility requirements

As New Zealand transitions to a highly renewable electricity system, the pattern of need for flexibility, and what resources provide such flexibility, is significantly changing.

In particular, the need for thermal stations to provide long-duration flexibility is *reducing* as renewable generation displaces it. So-called 'over-build' of renewables produces periods of high renewable flows — when it is particularly wet, windy, or sunny — where potential renewable supply exceeds demand. During these periods, some of the renewable generation is ‘spilled’ – typically, either water literally being spilled over the top of dams, or wind turbines being feathered to stop generating even though the wind would have enabled such generation. Having too much renewable generation at times of high renewable flows means the system is closer to having ‘just enough’ generation at times of lower renewable flows. In effect, spill becomes the flexibility resource.

This dynamic is also resulting in altered operation of the hydro reservoirs: lakes will generally be held higher, particularly in the build-up to the critical winter period, with the result that there is greater storage to be called upon during winter if it turns out to be dry.

The projected reduction in need for thermal generation to provide flexibility as the percentage of renewables increases is shown in Figure 21 and Figure 22 below. These show the variation in need for thermal generation to provide flexibility duties modelled using Concept’s ORC electricity market model. Several years are shown from 2025 through to 2050.

In addition to Concept’s base scenario inputs, the year’s labelled ‘Short’ are those where the system is assumed to have under-built renewable generation for whatever reason. In energy terms the under-build for the years 2029, 2030, and 2035 is 0.55, 1.05, and 1.50 TWh, respectively. This is equivalent to 36%, 78% and 140% of mean thermal TWh generation if the under-build had not occurred.

For a given future year and scenario of a system state (demand, generation build, fuel prices etc.) ORC models the operation of that system across 45 ‘weather years’. These use 45 years of historical, coincident renewable flows (hydro inflows, wind, sunshine) to determine how the system will operate based on these different weather patterns.[15]

For each future year and system state scenario, the figures show:

- Annual Max and Min values, being the highest and lowest amounts of thermal generation across the 45 weather years
- Winter totals for these Max and Min values.
  - Figure 21 is for the 6 months from Apr-Sep
  - Figure 22 is for the 3 months from Jun-Aug.
- The average annual percentage renewable generation across the 45 weather years – all on a cogen-exclusive basis.

Also shown (the far-left-hand element) is the historical variation in need for thermal generation to provide flexibility duties for the years 2000 to 2022, and with the % renewables simply being the average across all these years.

[15] The historical years are from 1980 to 2024, inclusive.

Figure 21: Variation in needed flexible thermal generation across weather years using 6-month (Apr-Sep) winter

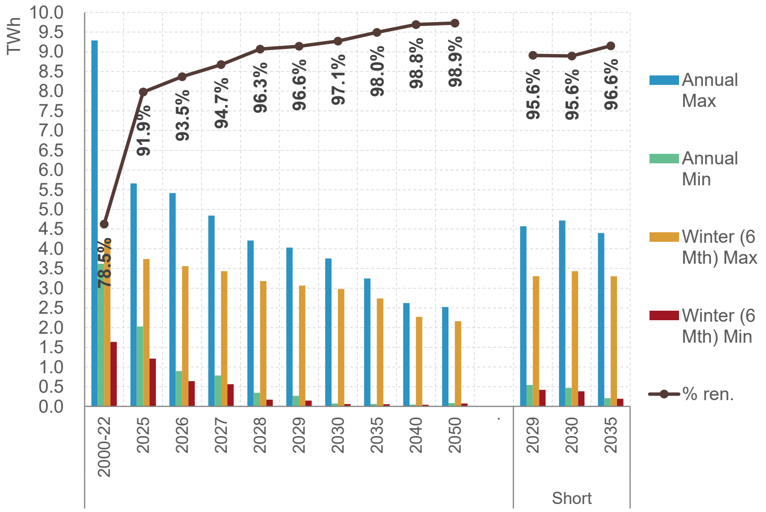
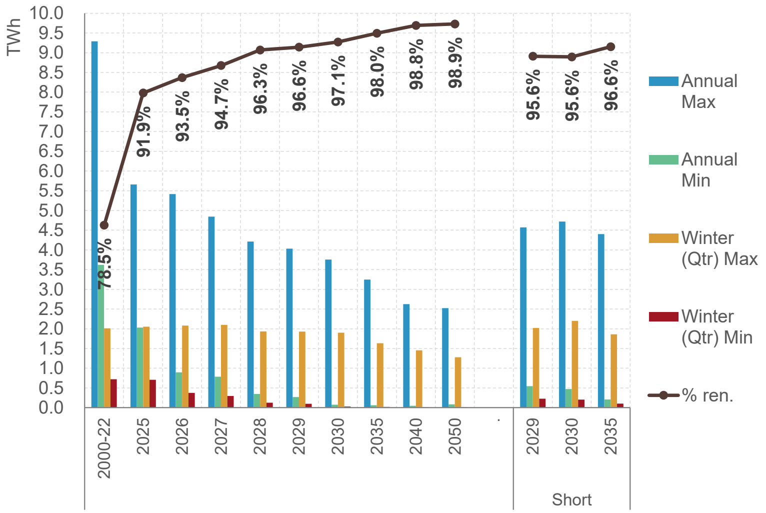


Figure 22: Variation in needed flexible thermal generation across weather years using 3-month (Jun-Aug) winter



For 2025 the model projected a maximum of ~5.7 TWh of thermal generation if the year had turned out to be the driest of the 45 weather years, and a minimum of ~2.0 TWh if it had been the wettest of the 45 weather years. (The actual level of non-cogen fossil for 2025 was 4.0 TWh.) The equivalent Max – Min numbers for winter are:

- ~3.7 to ~1.2 TWh for 6 months
- ~2.0 to ~0.7 TWh for 3 months

For future years, the amount of thermal generation is projected to decrease as the percentage of renewables increases. Thus, by 2030 in the base scenario with 97% renewables, the maximum annual thermal generation has fallen to ~3.8 TWh, and the minimum has fallen to virtually zero (~0.07 TWh).

The minimum amounts on a winter basis also fall as the % renewables grows, but the maximum amount falls much less slowly, particularly for the 3-month winter basis, where the maximum amount of thermal generation required of ~2 TWh barely changes until the % renewables reaches 98%.

Importantly, the stress scenarios where the system is short of renewable generation, don't result in significantly increased maximum thermal winter generation requirements. Relative to the modelled 3-month maximum for 2026, the 2030 stress scenario has an extra ~0.1 TWh required, whereas the 2029 and 2035 stress scenarios have smaller 3-month winter maximum requirements than in 2026.

There has been significant focus on the declining gas position over recent years. Accordingly, to understand the extent to which the general decline in the need for thermal generation to provide dry-year duties translates to a decline in the need for gas for dry-year duties, Figure 23 and Figure 24 below show the composition of the annual plant and fuel required for the different types of thermal generation for the Max and Min weather years and the Average across all weather years. It also shows the avoided fuel due to modelled operation of demand response from Tiwai and other demand.[16]

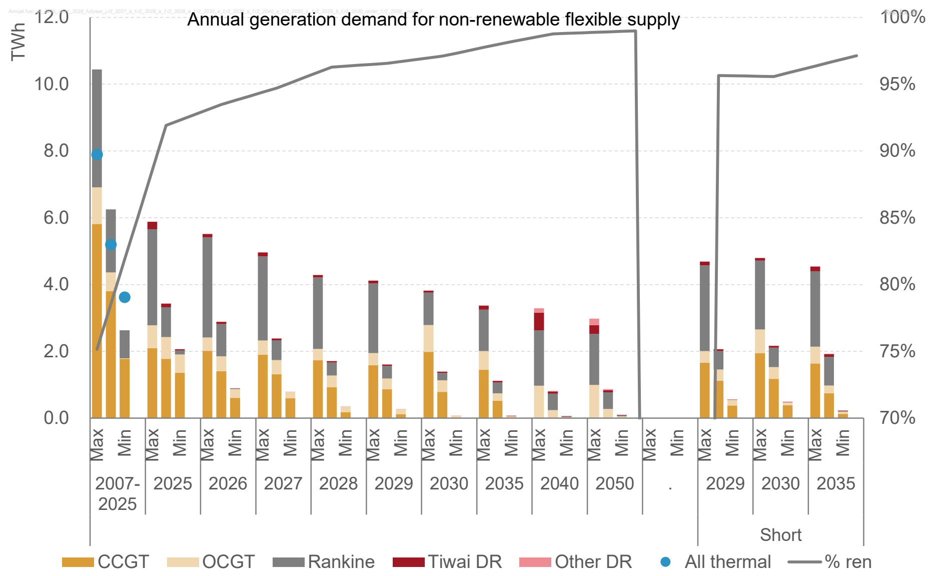
Also shown is the historical (2007 to 2025) range of fuel needed for flexible (ie, non-baseload) power generation. Note, for this historical figure, some of the gas will have been burned in Rankine units at times.

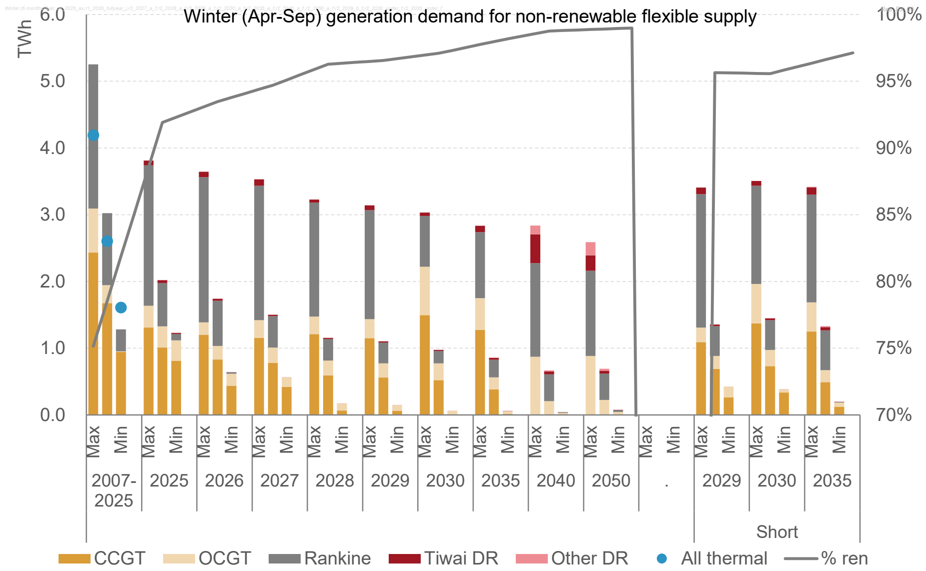
One key result that could help wider considerations around issues such as the potential sizing of an LNG terminal, is that the maximum requirement for gas-fired generation over the critical winter three-month period is 1 TWh, even in the significant market stress scenarios. (As illustrated in the bottom right graph in Figure 23).

[16] The avoided fuel for DR is based on an assumption that the avoided thermal plant has a heat rate equivalent to an OCGT.

Figure 23: Breakdowns of historical and projected annual generation for flexible thermal plant operation plus projected avoided generation from DR

Note: The reason the ‘All thermal’ values for the historical years are less/greater than the top of the max/min bars is because each element in the bar is for the max/min of that element, whereas the ‘All thermal’ values are for the time of max/min for all thermals – noting that the time of maximum generation for the Rankines, say, may not coincide with the time of maximum generation for the OCGTs.





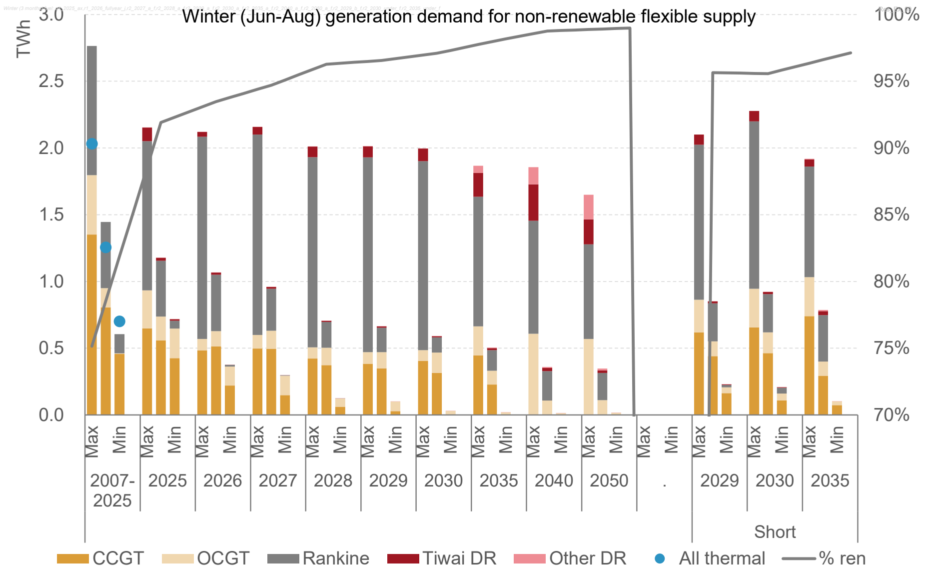
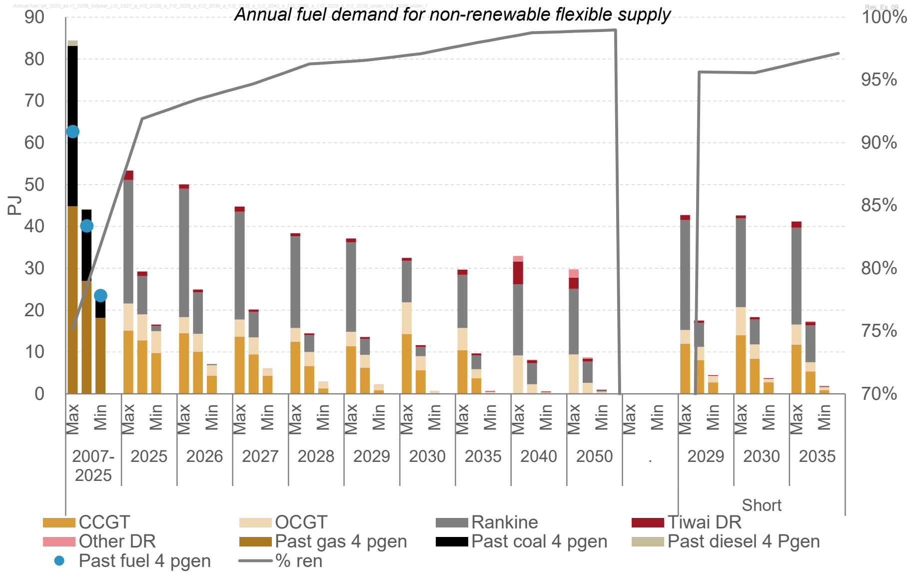
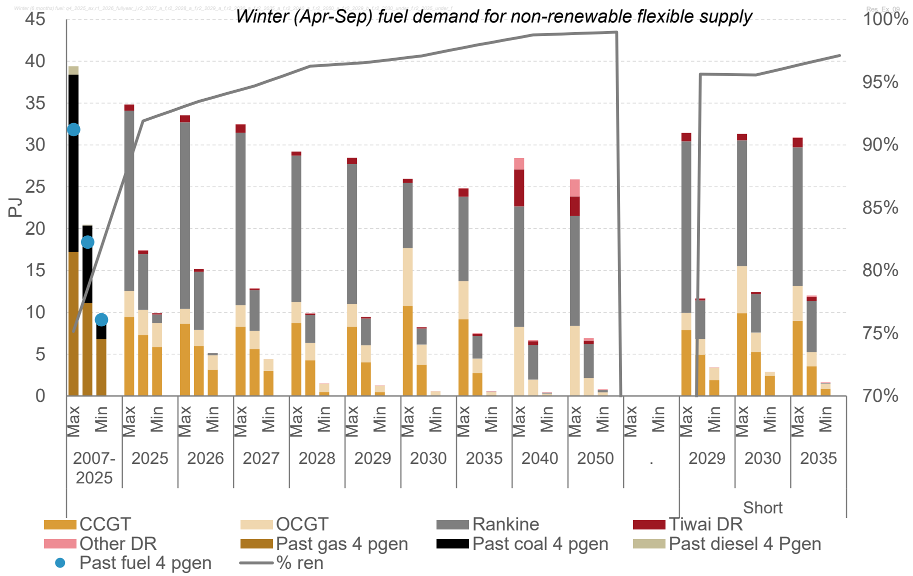
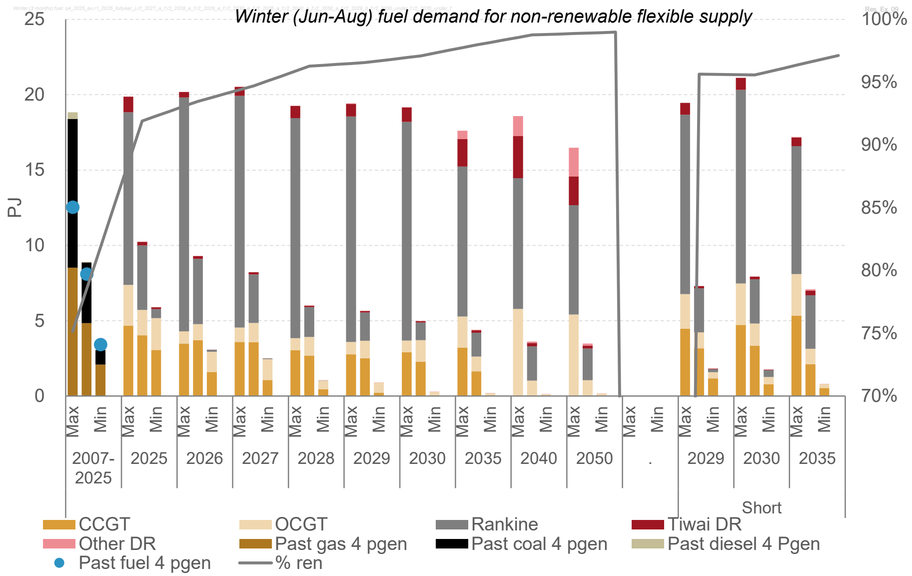


Figure 24:Breakdowns of historical and projected fuel for flexible thermal plant operation plus projected avoided fuel from DR
Note: The reason the ‘Past fuel 4 pgen’ values for the historical years are less/greater than the top of the max/min bars is because each element in the bar is for the max/min of that element, whereas the ‘Past fuel 4 pgen’ values are for the time of max/min for all fuel consumption – noting that the time of maximum generation using gas may not coincide with the time of maximum generation using coal.







The modelled % reduction in fuel for the Rankines (which can burn coal or gas) for both average and dry years is broadly the same as the % reduction in fuel for the gas-turbines (CCGT and OCGT): Relative to 2025, the reduction by 2035 is:

- an 80% reduction for average fuel consumption; and
- a 50% reduction for the driest year's fuel consumption.

A.2.2. Key insights as to the changing future need for thermal generation

In general, the following pattern can be discerned as the percentage of renewable electricity on the system grows:

- The overall need for thermal generation to provide long-duration flexibility falls significantly
- There is likely to be an even greater proportional fall in the need for gas for long-duration flexibility
- The need for thermal generation in the critical winter months is falling proportionately more slowly than the overall need for thermal flexibility. Ie, the need for thermal generation outside the winter months falls most significantly as the % renewables increases.
- There is no increase in the need for long-duration flexibility from thermal plant.

Given the above, statements about a highly renewable system making the dry-year problem worse or giving rise to a need for greater amounts of long-duration flexibility significantly mis-represent the changing nature of New Zealand's electricity flexibility requirements. The dry-year problem is not getting worse – indeed the over-build of renewables is *reducing* the need for flexibility resources from thermals or demand response.

What is changing is the pattern of need for flexibility as the percentage renewables on the system grows. The need to call upon flexibility resources other than renewable spill is becoming more heavily focussed in the winter months. This is largely due to

- the need for thermal generation generally being less in the summer and shoulder months (and thus being the periods that are first to be displaced by spill)
- the development of solar generation, which has a counter-seasonal generation profile, and thus increases the need for seasonal firming.

The system will require similar amounts of thermal capacity to that currently, but operated a lot less frequently.

This changing pattern of need can be seen in the charts on the following page which show the projected daily operation of the system for the driest and wettest of the modelled years for 2025 and 2035 base scenario runs.

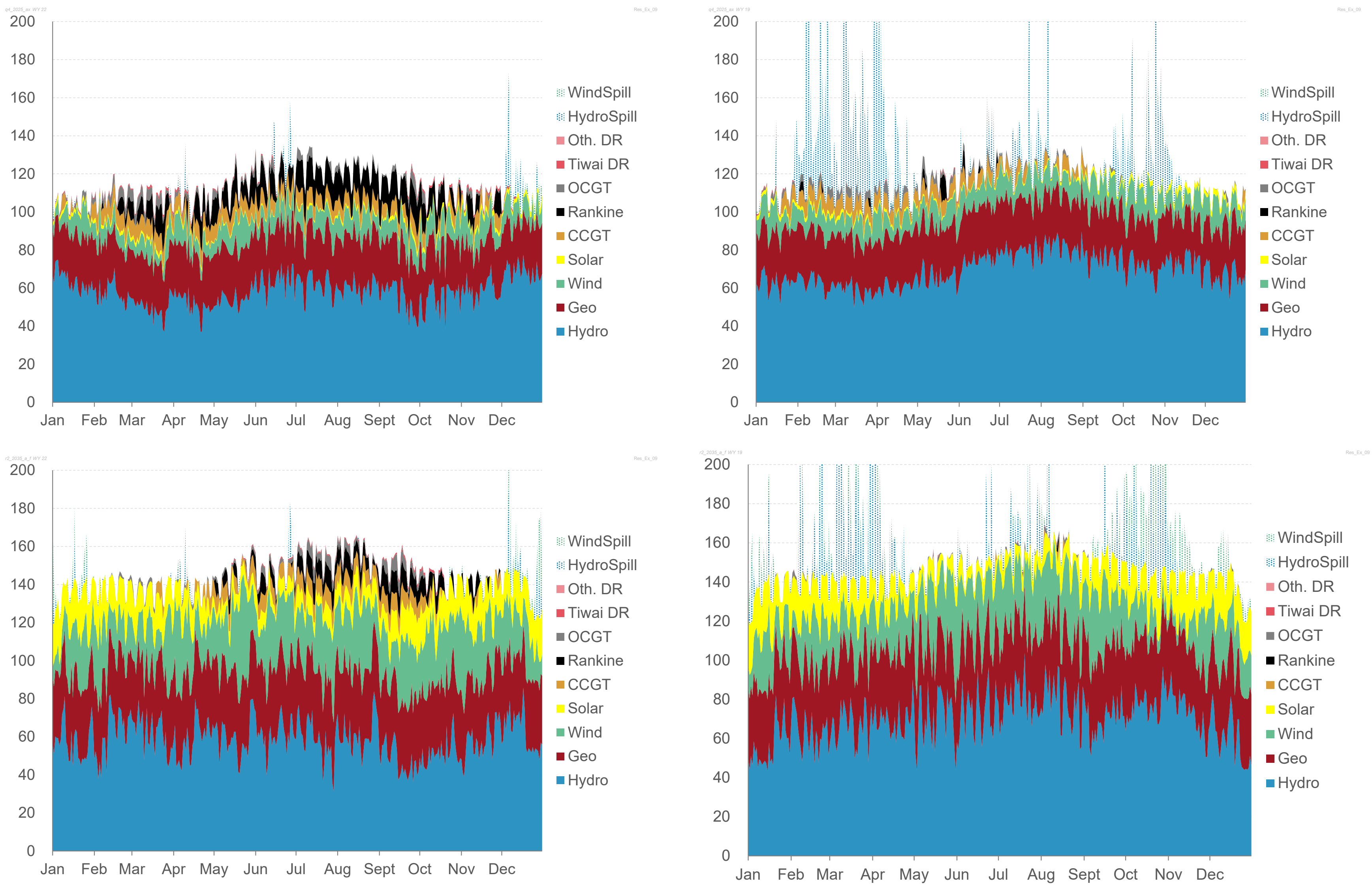
As can be seen, in 2025 there is a need for some thermal almost all of the time, except for a few wet weeks in summer in the wettest weather year.

In 2035, even in the driest year, there is no need for thermal in the spring and summer, and in the wettest year there is almost no need for thermal at all and significant amounts of spill occurring.

Driest **Wettest**

2025

2035

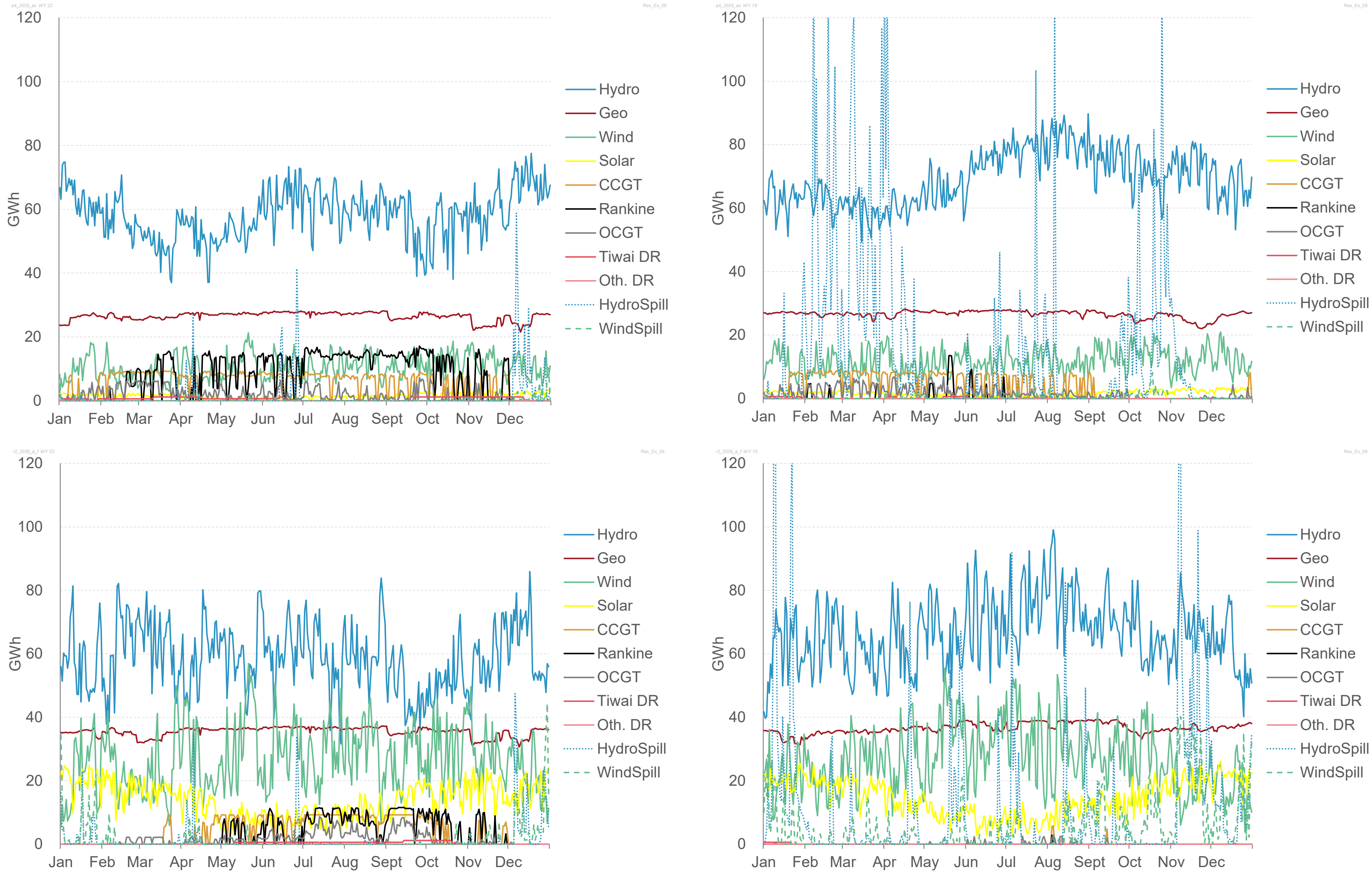


Driest

Wettest

2025

2035



As indicated by the following sets of graphs, a more highly-renewable system will also result in a much peakier post-renewable demand curve and consequent peakier need for thermal generation. In turn, this will drive peakier prices, even though the average price across weather years will be broadly the same.

They also illustrate how the duty of the thermal stations will become a lot less frequent.[17]

[17] Note: In our projections, the prices are consistent with achieving revenue adequacy for all generation plant – both the renewable plant that is built, and the thermal plant. For the thermal plant this revenue adequacy doesn't just cover fuel and other variable costs, but start-up costs, fixed O&M costs, and stay-in-business capex.

Figure 25: Duration curve of annual North Island prices across weather years for all scenarios

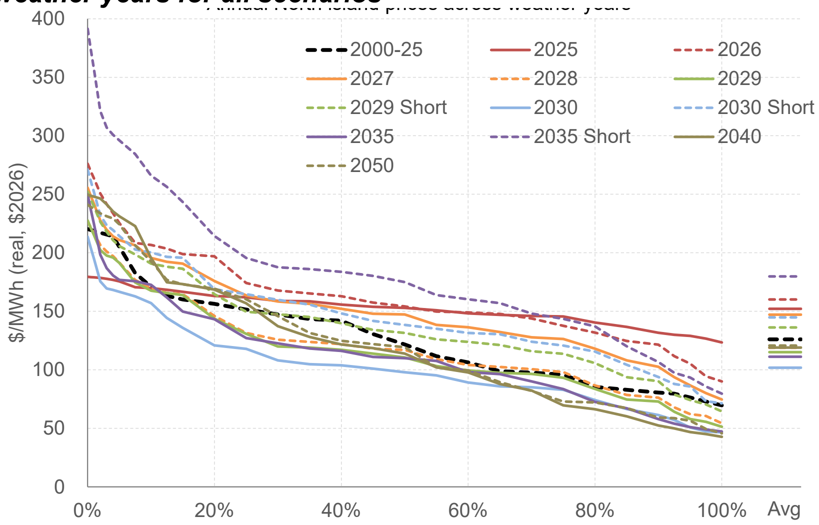


Figure 27: Duration curve of modelled hourly prices for different weather years for 2035 balanced scenario

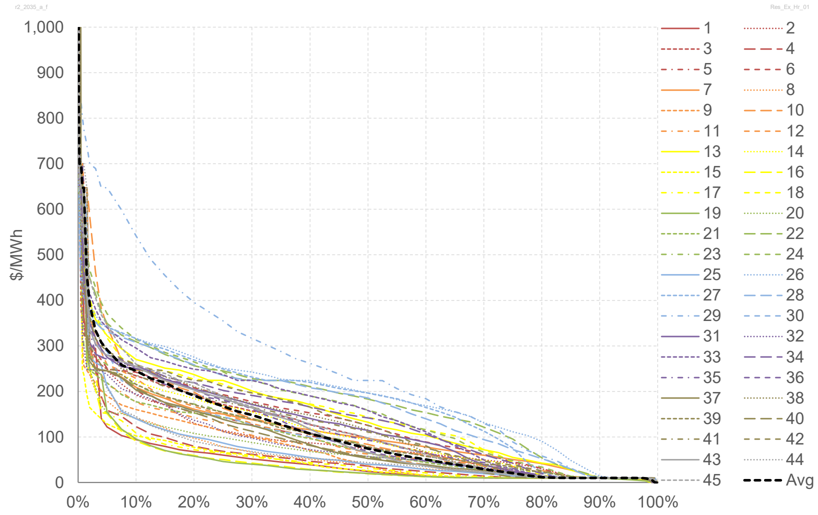


Figure 26: Duration curve of monthly North Island prices across weather year

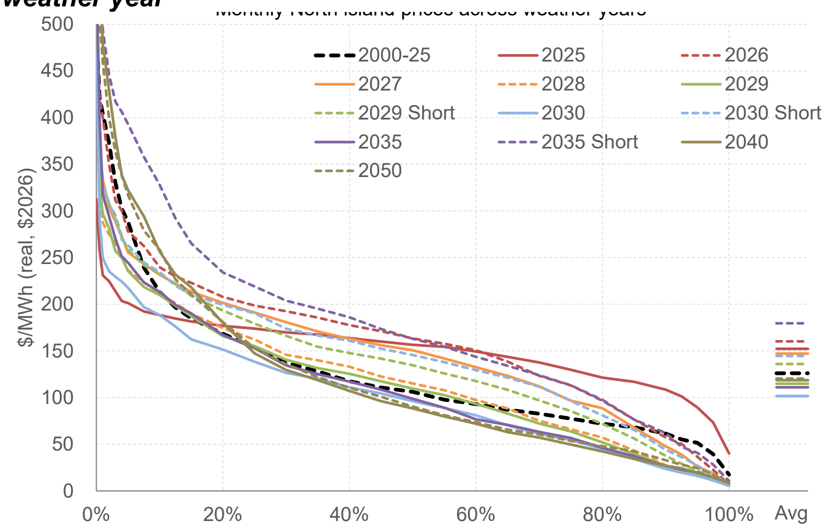


Figure 28: Duration curve of modelled hourly prices for different weather years for 2050 balanced scenario

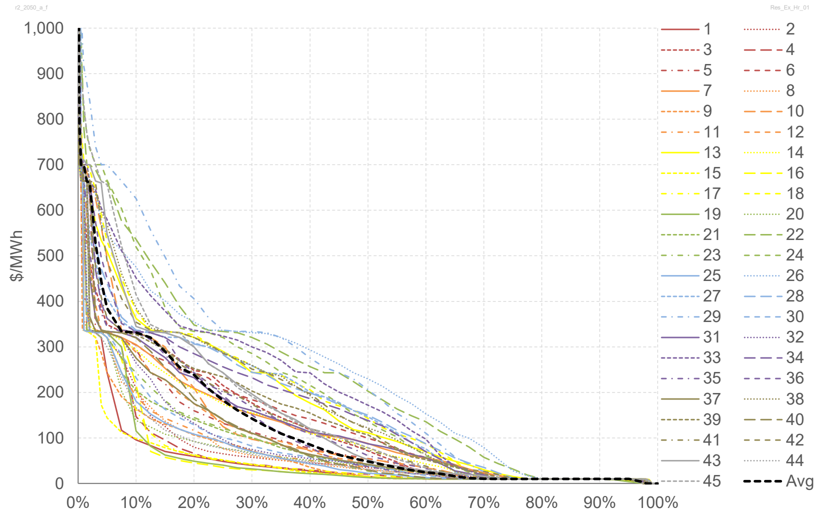


Figure 29: Duration curve of thermal generation across weather years for all scenarios

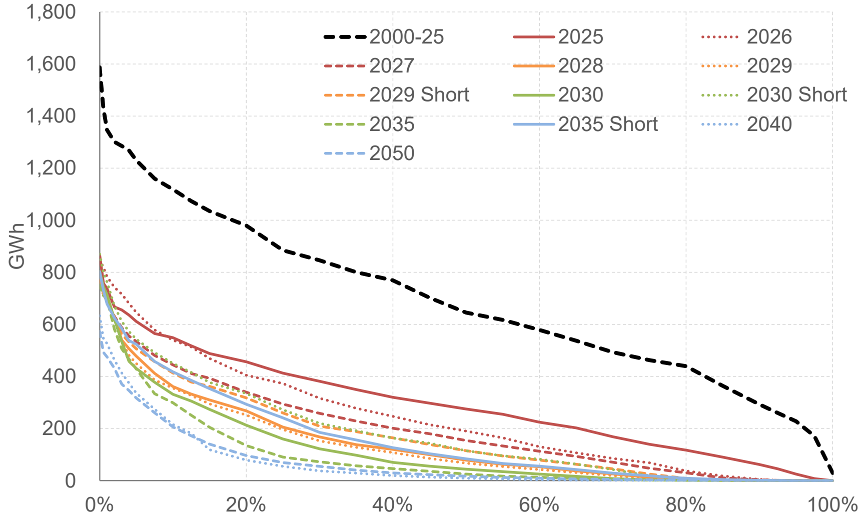


Figure 31: Duration curve of CCGT generation across weather years for all scenarios

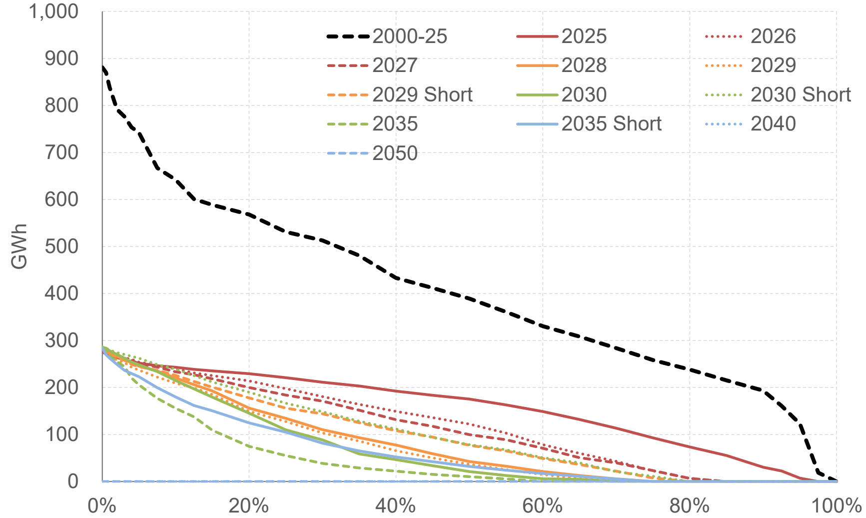


Figure 30: Duration curve of Rankine generation across weather years for all scenarios

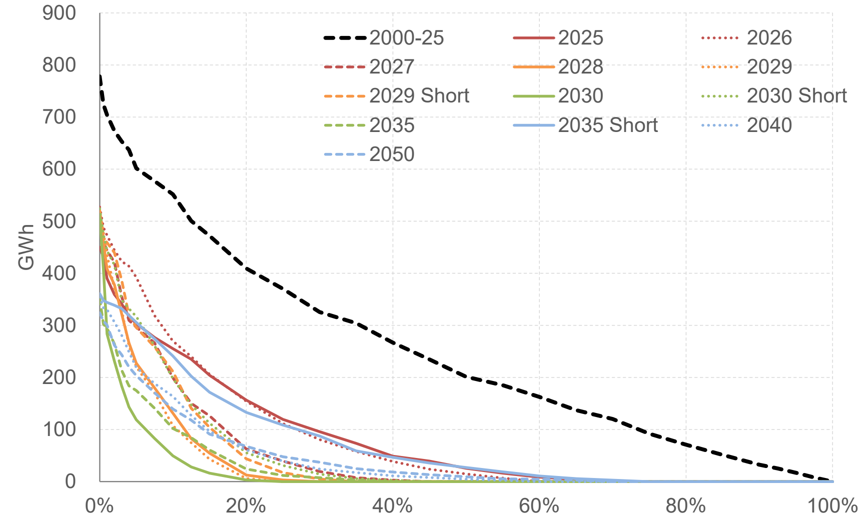


Figure 32: Duration curve of OCGT generation across weather years for all scenarios

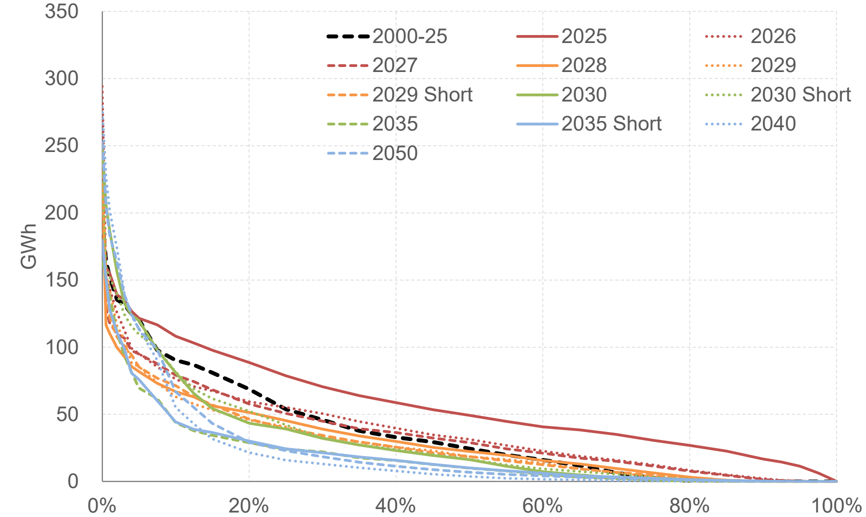


Figure 33: Modelled post-renewable duration curves for different weather years for 2035 balanced scenario

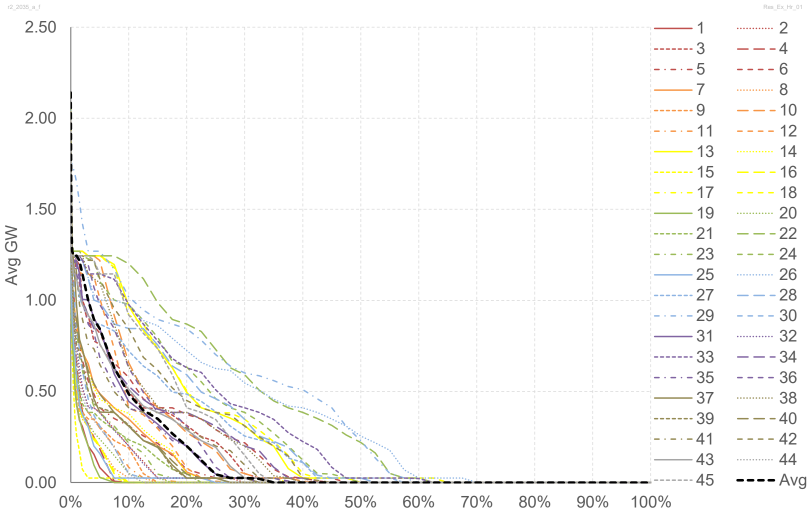


Figure 35: Modelled thermal duration curves for different weather years for 2035 balanced scenario

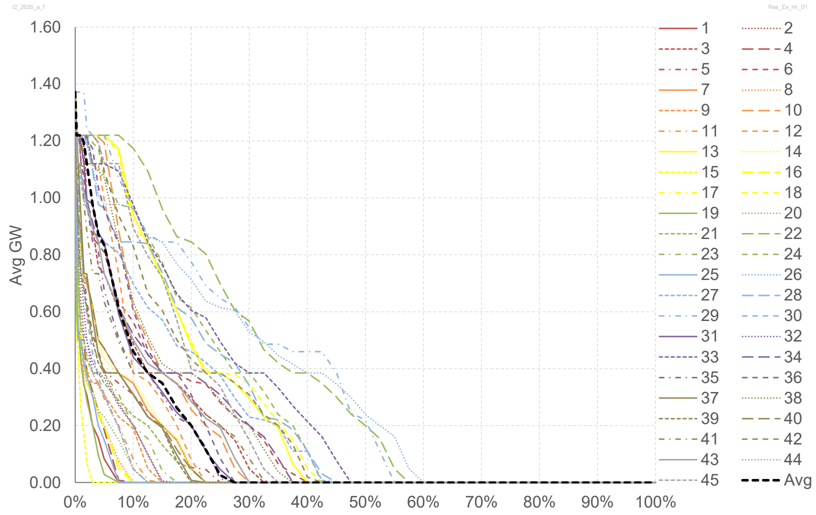


Figure 34: Modelled post-renewable duration curves for different weather years for 2050 balanced scenario

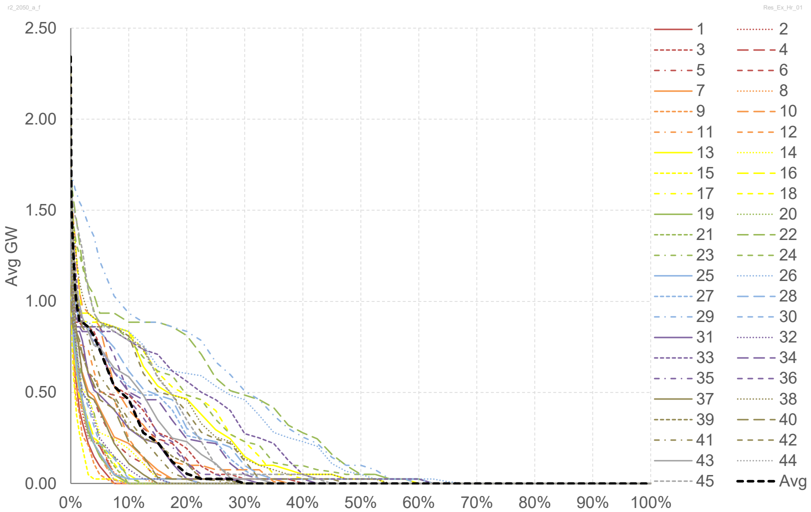
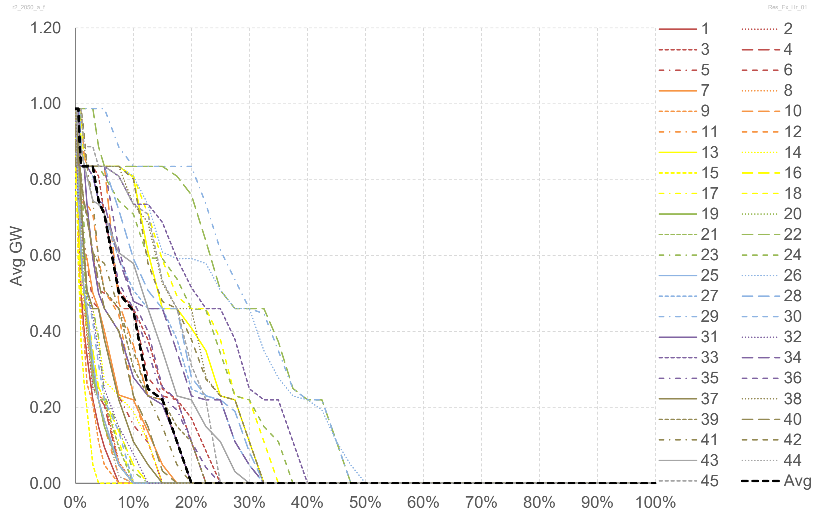


Figure 36: Modelled thermal duration curves for different weather years for 2050 balanced scenario



A.2.3. There will continue to be significant longer-term market driver uncertainties

Uncertainty grows the further out you look, but material uncertainty also exists in the near term (ie, 1–3 years).

- In the short term, unexpected failures of supply assets (generation stations, fuel supply), especially extended outages
- In the longer term, significant uncertainty over the factors driving the need for thermal flexibility resources:
  - The pace of demand growth and, more importantly, whether renewable build keeps pace with this growth, or instead lags or overshoots
  - gas price uncertainty due to uncertainty over:
    - gas field supply capability,
    - underground gas storage development, and
    - possible government intervention on LNG
  - carbon price uncertainty due to policy uncertainty around the ETS

Some are inherent 'state-of-the-world' uncertainties; others stem largely from national and international policy uncertainties.

Thermal generation is the flexibility resource most affected by these non-weather-driven uncertainties. For example, moving from a 98% to a 96% renewable market doubles the average thermal generation required.

This uncertainty will compound the already greater volatility and variability of thermal generation need in a highly renewable market.