Ensuring an Orderly Thermal Transition

Consultation paper

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ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

Like electricity sectors in other countries, New Zealand's power system is going through a period of significant change. As we transition to an electrified economy and an increased dependence on renewable energy, the system will need to transform to manage supply and demand effectively and efficiently.

This paper focuses on a key aspect of that transition – ensuring an orderly transition of thermal generation plant. The paper outlines the Electricity Authority's understanding of the risk, its underlying causes, and possible options to address it. The Ministry for Business, Innovation and Employment (MBIE) is also doing work in this area, considering market measures in terms of the Emissions Reduction Plan (ERP).

The desired outcome of this workstream is that the regulatory settings should support an efficient transition to a renewables-based system. This should avoid both poor reliability (if there is insufficient back-up resource from thermal generation) and excessive costs and emissions (if there is too much thermal generation).

Future demand profile for thermal generation

The Authority engaged Concept Consulting Group (Concept) to analyse the likely demand for (and supply of) thermal generation over the coming transition period. Forecasts will always have an element of uncertainty, but the analysis helps shed light on broader issues such as whether changes in thermal demand are imminent, and how demand for different types of thermal generation is likely to change over time.

Concept's analysis builds on earlier work by organisations such as Transpower[1] and the Climate Change Commission[2], but uses the latest publicly available information. It also explores some key issues in more detail – especially the effect of start times and the related costs for different thermal units. Concept's full report can be found under Appendix B. In terms of policy assumptions, the analysis reflects the ERP released in May 2022. The ERP adopted a formal target of 50% of total final energy consumption (TFEC) coming from renewable sources by 2035.[3]

In summary, Concept's base case projections indicate:

a. The overall downward trend in demand for thermal generation will continue over the coming decade, as it switches out of baseload and into back-up services for a renewables-based electricity system. By 2032 thermal generation will be about 1.5% of total supply,[4] compared with the last five years, when thermal generation averaged 14% of total supply.

b. In the near term (represented in the study by the year 2025) the demand for thermal generation is projected to remain significant. The pace of renewable development will

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1 See https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/publications/resources/TP%20Whakamana%20i%20Te%20Mauri%20Hiko.pdf?VersionId=FljQmfxCk6MZ9mIvpNws63xFEBXwhX7f

2 See www.climatecommission.govt.nz/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

3 See https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf. The ERP did not contain a formal target for the share of electricity generation coming from renewable sources. Rather, it indicated the Government continues to support its aspirational target of 100% renewable electricity by 2030, and that the target would be reviewed in 2024.

4 The ratio is an average over many weather years.

take time to catch up with electricity demand, and Concept notes that the Tiwai smelter is expected to continue to operate post 2024.

c. In 2025 all thermal units not already scheduled for closure appear likely to be able to cover their go-forward costs. However, thermal units (and especially the Rankine units) would have significant volatility in their net cashflows if reliant solely on spot market revenues due to the impact of weather variability on thermal demand and spot prices. Forward contracting could reduce that level of volatility.

d. However, by 2032 (the second year analysed in the Concept study) there is unlikely to be sufficient demand for thermal generation to support the retention of all existing thermal units. By that date, retirement of some slower-start capacity (either a combined-cycle unit or some Rankine units) appears likely to be efficient. However, demand for fast-start back-up remains strong with continuing demand for service from all existing open cycle units.

e. The potential for investment in additional fast-start capacity to become economic appears unlikely in the base case. A mix of existing fast-start and some slower-starting thermal plant appears to be capable of meeting the demand for thermal generation to at least 2032 under base-case assumptions.

Potential sources of thermal transition risk

The declining demand for thermal generation will clearly present a more challenging environment for thermal generators. By itself, that change should not trigger inefficient retirement or retention outcomes. If thermal units can provide back-up for renewables cheaper than the alternatives, there should be sufficient financial rewards to keep them available.

However, this outcome is predicated on:

a. Information – wholesale market participants (including retailers, industrial consumers, and generators) need to have sufficient information about the likelihood and consequences of possible thermal retirements/investments to make informed decisions.

b. Incentives – wholesale market participants need to face incentives to act in a way that reflects consumer preferences, so private incentives align with the public interest.

Section 4 of this paper identifies a range of factors that could cause information or incentive gaps, and in turn contribute to inefficient thermal generation retirement/investment decisions. The Authority is seeking stakeholder views on the extent to which these gaps exist, and whether there are any other factors that could lead to inefficient retirement/retention decisions.

High-level options to address thermal transition risk

In light of the Concept modelling, the Authority has concluded that the risk of disorderly thermal exit is low at present. Nevertheless, there are certain interventions that have either been suggested by the MDAG work, or that are being progressed in terms of the Winter 2023 project, that would further reduce thermal transition risks. These are mentioned in Section 5 of this paper, along with some commentary on options that the Authority has already considered but has decided not to progress, for example a strategic reserve and a capacity mechanism. This proactive approach to option identification ensures the Authority can monitor the situation and take action, as and when necessary.

Section 5 of this paper identifies these options and has undertaken a preliminary assessment of them, summarised in Table 3 of the paper.

Next steps

The Authority welcomes feedback on the issues discussed in this paper. This feedback will inform the Authority's decisions about any further work.

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1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this paper is to consult with interested parties on the risks that may arise in the transition to a renewables-based electricity system, in particular the risk of premature retirement of thermal generation plant.[5]

1.2 The consultation paper outlines the Authority's understanding of thermal transition risks, and some initial work by the Authority, supported by quantitative analysis by Concept Consulting, has determined the risks are likely to be low. The Authority will monitor these risks during the transition, recognising they could increase in future. Several options to mitigate thermal risks are considered in this paper, in case the risks should increase. The Authority would also value the views of stakeholders on these matters.

How to make a submission

1.3 The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to fsr@ea.govt.nz with "Consultation Paper— Ensuring an Orderly Thermal Transition" in the subject line.

1.4 If you cannot send your submission electronically, please contact the Authority (fsr@ea.govt.nz or 04 460 8860) to discuss alternative arrangements.

1.5 Please note the Authority intends to publish all submissions it receives. If you consider the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider the Authority should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if it agrees not to publish your full submission).

1.6 If you indicate there is a part of your submission that should not be published, the Authority will discuss this with you before deciding whether or not to publish that part.

1.7 However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.8 Please deliver your submission by **5pm** on **Tuesday, 25 July, 2023**.

1.9 Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority (fsr@ea.govt.nz or 04 460 8860) if you do not receive electronic acknowledgement of your submission within two business days.

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5 The Authority recognises some thermal generators may in future use a renewable fuel as a primary energy source, such as biodiesel or wood pellets. However, this paper only considers generators that use fossil fuels as their primary energy source and refers to these as "thermal generators".

2 Introduction

Context for thermal transition risk work programme

2.1 New Zealand is transitioning to a renewables-based electricity system. As the transition occurs, the need for fossil-fuelled thermal generation will continue to decline.

2.2 This paper focuses on the risks that there is not an orderly closure of thermal plant. It is designed to understand the risks that could potentially arise in the transition to a renewables-based system and consider options that best mitigate those risks.

2.3 This work fits within a broader suite of wholesale market initiatives being progressed by the Authority. The Wholesale Market Review considers measures to promote competition and has identified a need to understand thermal generation risks in the transition to a renewables-based system.[6] The Authority's Market Development Advisory Group (MDAG) is considering how price discovery will operate in a renewables-based system and also raised thermal transition risk as an issue requiring further analysis and consideration.[7]

2.4 MBIE (the Ministry for Business, Innovation and Employment) is undertaking work, as outlined in the Government's emissions reduction plan, to investigate the need for additional electricity market measures that support affordable and reliable electricity supply while accelerating the transition to a highly renewable electricity system. This work is looking at a range of transition challenges, including

(a) Facilitating sufficient investment in new renewable generation to support other parts of the economy such as transport and industry to move away from fossil fuels,

(b) maintaining electricity security of supply and affordability as New Zealand transitions away from, and replaces the roles of, fossil fuels in the electricity system, and

(c) enabling timely network investment to support new renewable electricity generation and electrification.

Desired outcome

2.5 The desired outcome of this workstream is that the right (efficient) level and type of thermal generation capacity is available during the transition to a renewables-based system. This should avoid the adverse outcomes of poor reliability (if there is insufficient back-up resource such as thermal generation) or excessive costs and emissions (if there is too much thermal generation).

1. Do you agree with the desired outcome as described? If not, what do you think is the desired outcome in respect of thermal generation during the transition?

6 See https://www.ea.govt.nz/documents/2243/Promoting-competition-in-the-wholesale-electricity-market.pdf

7 See https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf

This paper focuses on investment-related risks rather than operational risks

2.6 During the transition to a renewables-based system two different challenges could emerge in relation to thermal generation:

(a) Operational problems – even if there is sufficient plant installed to meet the system's residual thermal demand, some units may not be able to operate when needed. For example, some slower-starting units may not be ready to generate if needed on a cold winter's night.

(b) Investment problems – there may be insufficient plant capacity installed to meet the system's residual thermal demand because some plant has been retired prematurely and/or investment in desirable new plant has not occurred.

2.7 The Authority has already considered *operational* transition risks in a consultation paper released in November 2022.[8] That paper explored the risk of some existing thermal units not being available when needed (the so-called unit commitment risk).

2.8 Following consideration of submissions and further technical work by the system operator, the Authority released a decision paper confirming it would pursue five options for potential implementation by winter 2023 and undertake work on five others for potential implementation after winter 2023.[9] Because those papers discussed operational-transition issues in some detail, the balance of this paper focuses on transition risks related to thermal plant *investment* decisions. In particular, these are:

(a) Risk of premature thermal retirement – this refers to the possibility that a thermal unit retires even though retention would have net public benefits – i.e. inefficient dis-investment occurs.

(b) Risk of delayed or inadequate thermal investment – this refers to the possibility that investment in new thermal capacity would be beneficial but does not occur in a timely way. At first sight this risk may seem counter-intuitive when the system is transitioning to renewables. However, investment in new thermal units might be worthwhile to replace existing less-flexible, slow-start thermal units with flexible, fast-start units. If so, it is useful to consider whether that beneficial investment will be delayed or not happen at all.

2.9 This paper does not directly consider investment decisions related to the provision of gas supply as that matter is outside of the Authority's area of responsibility. Having said that the Authority recognises that the availability of gas can affect retention/investment decisions for thermal generators.

2.10 In that regard MBIE, with its Gas Transition Plan and Electricity Market Measures work, is considering gas supply issues and will be seeking feedback on a range of issues relating to support mechanisms for gas availability for the electricity market. This includes seeking feedback on issues relating to gas supply and storage arrangements for the electricity sector, and consideration of alternatives or supplements to supply

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8 See https://www.ea.govt.nz/documents/1630/Driving_efficient_solutions_to_promote_consumer_interests_through_winter_2023.pdf

9 See https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

arrangements in the gas sector to provide reliable and diversified sources of gas, such as renewable gases or Liquified Natural Gas importation.

2. Are there any other aspects of thermal transition risks that should be considered by the Authority?

Structure of this paper

2.11 This paper is structured around three key questions:

(a) How is the transition to a renewables-based system likely to affect the demand for thermal generation and New Zealand's thermal plant fleet? This question is discussed in section 3.

(b) What are the key underlying sources of thermal transition risk? This question is discussed in section 4.

(c) What are the potential options to mitigate thermal transition risks? This question is discussed in section 5.

3 Projected thermal generation capacity in the transition

Overview

3.1 This section provides an overview of the existing thermal generation fleet in New Zealand. It also summarises the results of quantitative analysis about how the demand for services from thermal generation is likely to change over the coming decade. The information in this section helps to set the scene for the discussion of policy-related issues in the next two sections.

Current thermal generator units

3.2 Table 1 provides a summary of the thermal generation fleet in New Zealand.

3.3 Thermal generation has historically performed four broad roles:[10]

(a) Supply of baseload energy – this refers to generation that runs continuously, for which low running costs and high fuel conversion efficiency were important. For these reasons, baseload thermal generation has come mainly from the combined-cycle units.

(b) Supply of seasonal energy – this refers to additional energy needed to offset the lift in electricity demand and decline in hydro inflows (as precipitation falls as snow rather than rain) that generally occurs over the colder months of the year. This service has come from a mix of thermal generation units.

(c) Supply of peaking energy – this refers to generation that can be rapidly increased to meet short-term needs, such as high 'peaking' demand associated with cold weather. Increasingly this service is also required to offset short-term fluctuations in supply from intermittent renewable sources,

10 The descriptions below provide a high-level summary. In practice, the boundary between seasonal, peaking and firming services is not always clear-cut. Thermal units may also provide ancillary services.

such as wind and solar. Open-cycle units have been well suited to this service because they start quickly. Other units can also provide peaking services if they are already warm or hot and are running below their maximum output.

(d) Supply of hydro-firming energy – this refers to generation that increases to offset periods of sustained low hydro generation. Like peaking services, this type of operation is sporadic, but tends to occur for longer durations (weeks rather than hours), albeit with longer periods between use. In recent years, this role has been mainly performed by the Rankine and combined-cycle units.

3.4 In this paper, we mainly refer to the latter three categories as back-up supply.

Table 1. Existing thermal generators in New Zealand[11]

Source: Company data

Thermal generation unit	Fuel	Operator	Capacity (MW)	Built	Comment
Open-cycle gas turbines (OCGTs)					
Junction Road	Gas	Nova	2x50	2020	Fast starting
McKee	Gas	Nova	2x50	2013	Fast starting
Stratford	Gas	Contact	2x105	2010	Fast starting
Whirinaki	Diesel	Contact	3x52	2004	Fast starting
Huntly 6	Gas	Genesis	51	2004	Fast starting
Sub-total OCGT			617		
Combined-cycle gas turbines (CCGTs) and Rankine-cycle (RC) units					
Huntly 5 (CCGT)	Gas	Genesis	403	2007	Slower starting
TCC (CCGT)	Gas	Contact	377	1998	Slower starting
Huntly 1,2,4 (RC)	Gas/coal	Genesis	3x250	1983	Slower starting
Sub-total			1,530		
Total			2,147		

Potential demand for thermal generation during the transition

3.5 Most forecasters are predicting a downward trend in the demand for thermal generation over coming years. They expect thermal baseload generation to cease and that during the transition, thermal plant will be mainly devoted to providing back-up services.

3.6 The key reason for this change is that higher carbon prices and rapidly declining costs for renewables and batteries have made thermal generation uneconomic as a provider of baseload energy when compared with new renewables generation. Furthermore, higher carbon charges also make thermal generation more expensive as a source of back-up services and expand the scope for other forms of flexibility, such as demand response or batteries, to be competitive.

3.7 In summary, the demand for thermal generation is expected to contract significantly over time, and eventually disappear altogether, after the transition. While the direction of travel is consistent among forecasts, there is uncertainty about the exact trajectory.[12]

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11 Co-generation plant is not shown in the table or included in the quantitative modelling but is unlikely to affect the conclusions in the Concept report (see pages 7 & 8 of the Concept report in Appendix B).

12 Comparisons are also complicated by methodology differences, such as whether co-generation is included in reported renewable/thermal ratios, and whether the Tiwai smelter is assumed to continue to operate.

Concept's projections of potential future thermal demand

3.8 The Authority engaged Concept Consulting Group (Concept) to project the demand for thermal generation over the coming transition period. This report builds on analysis by Transpower, the Climate Change Commission and others over the last three years. It uses the latest publicly available information and explores some key issues in more detail. It incorporates the effects of thermal unit start times and the cost of starting a cold unit on the future generation mix.

3.9 In terms of policy assumptions, Concept's analysis reflects the Government's ERP released in May 2022. The ERP contains a formal target to have 50% of all final consumer energy coming from renewable sources by 2035. The ERP did not contain a formal target for the share of electricity generation coming from renewable sources. Rather, it indicated the Government continues to support an aspirational target of 100% renewable electricity by 2030, and that the target would be reviewed in 2024.[13]

3.10 Like any forecast, the Concept analysis has uncertainties, but it can shed light on broader issues such as whether changes in thermal demand are imminent, and how demand for different types of thermal generation is likely to change over time.

3.11 The Concept report can be found under Appendix C in this document. Key observations are summarised below.

Steep downward trend expected for average thermal generation levels

3.12 Figure 1 shows the percentage of generation from thermal generation in recent years and projections for two future reference years: 2025 and 2032.[14]

3.13 The 2025 reference year was chosen to assess how quickly the demand for thermal generation is changing in the next few years. This helps gauge the degree to which retirement/retention decisions may be imminent based on underlying system fundamentals. The 2032 reference year was chosen to be some distance into the future (almost a decade), when the system is likely to have completed much of the thermal transition.[15]

3.14 The year 2025 is sufficiently close that one can be reasonably confident about the amount of renewable generation that will be on the system, as it takes time to consent, connect, and build new generation. The projections for this year take account of all public data about existing, committed and highly likely new renewable projects. It also incorporates the retirement of thermal units that have been announced by owners.[16]

3.15 For the 2032 reference year there is less certainty about what renewable plant will be built (among other things). Instead of compiling a forecast based on specific additional new plant developments, the projection is based on the expectation that new renewable projects will be built if their lifetime net revenues are positive (the plant is 'revenue

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13 See https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf.

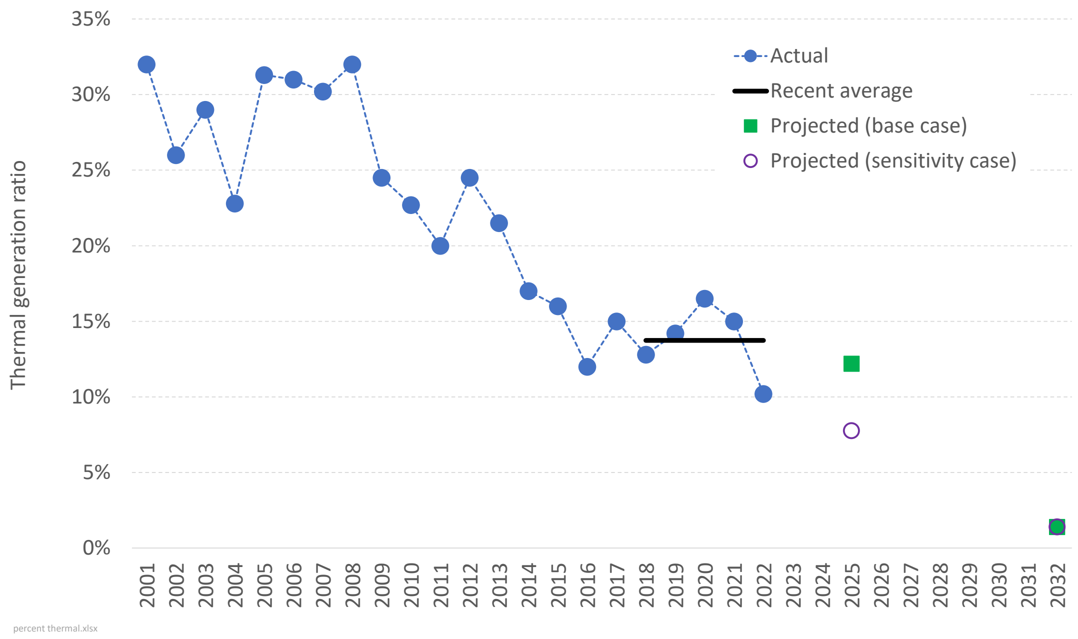
14 The output from co-generation plant has been excluded from the analysis because its main purpose is to provide process heat to the host industrial consumer, rather than to generate electricity. Concept states however (on page 8 of their report) that the exclusion of cogeneration from the modelling is unlikely to affect their conclusions.

15 Intermediate calendar years were not modelled because it is very computationally intensive to model each calendar year – noting the analysis considers 40 different weather years and many plant mix combinations for each of the reference years.

16 For example, the analysis includes development of the Tauhara geothermal plant and retirement of the Taranaki Combined Cycle unit respectively.

adequate' for the owner). In effect, this means that the overall balance between system demand and supply is expected to be in equilibrium in 2032 (unlike 2025 when it is tight).

Figure 1: Percentage thermal generation



3.16 As shown in Figure 1, the thermal share has declined from around 32% in 2001 to an average of approximately 14% in the last five years. There were yearly fluctuations around the downward trend, largely due to variation in hydro inflows. For example, 2022 had relatively high inflows resulting in a thermal percentage close to 10%.

3.1 The chart also shows the projected thermal ratio[17] for the two reference years. For the 2025 year the thermal percentage is projected to be around 12%. For the 2032 year the thermal percentage is projected to fall to only 1.5%. The projections shown on the chart are the modelled mean thermal percentage across many 'weather years'. Depending on hydro inflows and other renewable generation, the percentage can vary from approximately 4% to 20% in 2025, and from 0.3% to 4.5% in 2032.

Solid demand is expected for thermal generation in the next few years

3.2 Figure 2 shows projected thermal demand in 2025 expressed in GWh terms and by plant type. The projected level for 2025 is an average over all weather years, whereas the historical levels reflect the actual weather in those years.

3.3 The projected demand for thermal for 2025 is slightly lower than levels observed in 2019-2021, but above the levels observed in 2018 and 2022 (both of which were 'wet years').[18] The composition of thermal output is projected to change, with more from OCGT peakers and less from the slower-starting CCGT and Rankine units. However, despite the shift in the duty between units, significant demand remains for all thermal generation types.

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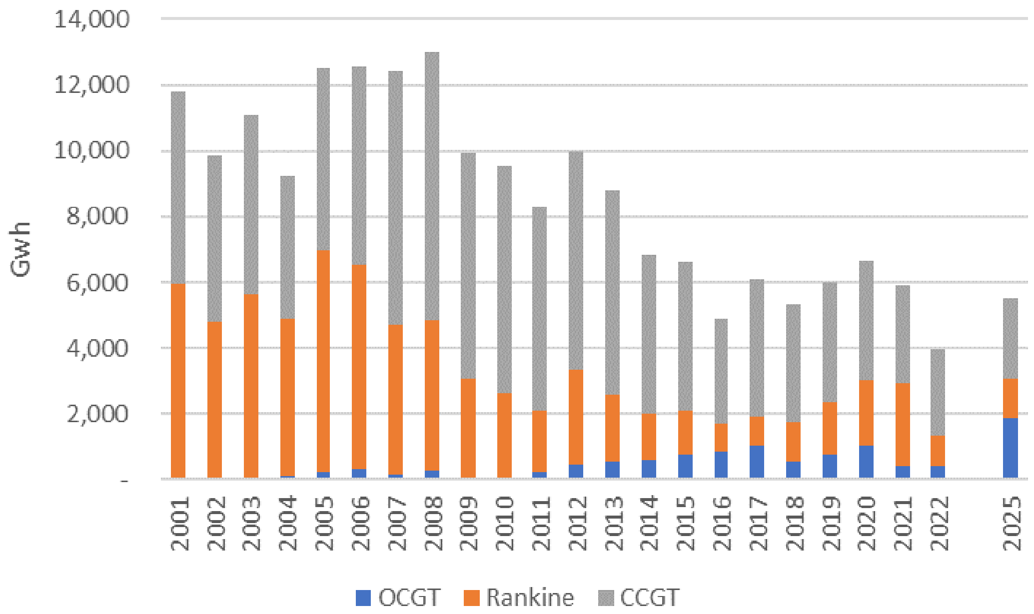
17 As discussed below the ratios shown are averages computed across 40 weather years in the model.

18 A decline in the thermal contribution is nonetheless projected because the total supply is projected to increase in 2025 compared to the past.

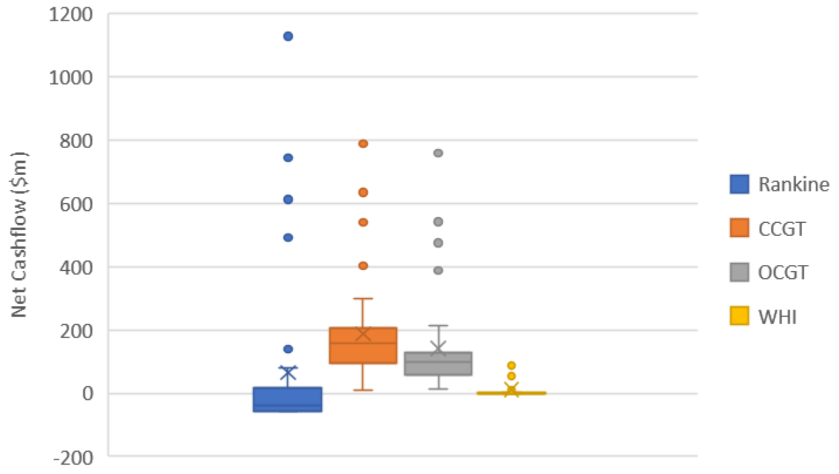
Figure 2: Historical and projected GWh by thermal plant type in 2025



3.4 The Concept analysis also considered the outlook from the perspective of thermal plant owners. Concept estimated annual net cashflows for Rankine, CCGT, OCGT and diesel-fired units in 2025 assuming operators are reliant solely on the spot market for revenues. The revenue data was combined with estimates of go-forward costs for the units based on public sources.

3.5 The net cashflow figures take account of items such as carbon and fuel costs, variable operating costs and stay-in-business capital costs. Concept considered that go-forward net revenues are likely to be a key measure for thermal operators facing retention or retirement decisions. If a unit is not expected to generate positive expected net revenue, it seems unlikely it would remain in service. However, note that the cashflow measure excludes any allowance for a return on pre-existing capital investment, although thermal owners might be unwilling to keep a plant in service without at least some return on sunk investment. To that extent, the results may understate the likelihood of retirement.

Figure 3: Net cashflows by thermal plant type – base case 2025



3.6 Figure 3 presents the results of the analysis as a ‘box and whisker’ graph. The mean net cashflow (averaged over all weather years) is shown by the X for each of the different types of thermal unit. The inter-quartile range is shown by the shaded box, and the whiskers indicate the range within which most values lie. The individual dots represent outliers, or observations well outside the rest of the distribution.[19] Key observations are:

(a) Mean measures of net cashflow are positive for all generation types, but there is significant variation in net cashflows across weather years.

(b) For CCGTs and OCGTs (including Whirinaki) the expected net cashflow range is positive across all weather years.

(c) For the Rankine units the mean expectation is for positive net cashflow, but due to appreciable stay-in-business costs and a running cost that is higher than the gas-fired units,[20] the Rankine units would have negative net cashflows in many years if they were solely reliant on spot market sales for their revenue. Indeed, the median (shown by the middle line in the chart) is also negative, indicating that in the majority of years the Rankine units would have negative net cashflows if reliant solely on spot market sales for their revenue. On the other hand, the highest net cashflow outcomes on the chart are for the Rankine units. The units are projected to make substantial net positive cashflows in extremely dry years due to their large generation capacity and ability to generate for long periods if required. Having said that, the probability of any given year being extremely dry is low.

3.7 Overall, the results suggest that under the base-case assumptions, thermal units that have not already been scheduled for closure[21] should have a revenue-earning opportunity sufficient to cover their go-forward costs. However, the thermal units (and especially the Rankine units) would have significant volatility in their net cashflows from

19 Although those observations are outside the rest of the distribution, they are included in the calculations of the mean, median and inter-quartile range.

20 This is the case under “normal” conditions, but when gas storage is very low the marginal price of gas can increase enough to make Rankine units running on coal a lower cost option.

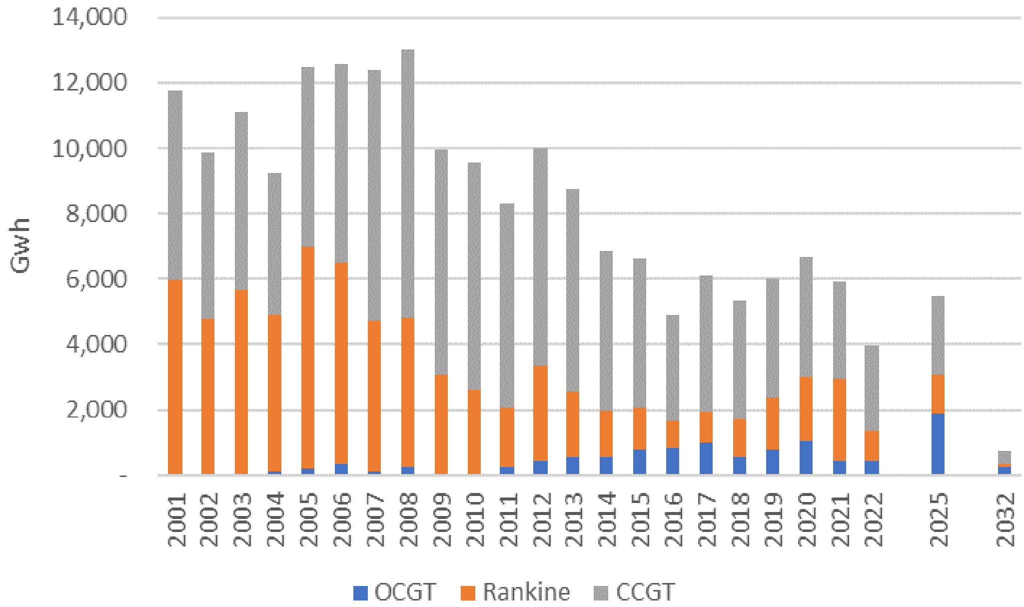
21 All units except TCC and Te Rapa which are scheduled for retirement before 2025.

spot-market revenues due to weather variability. If thermal operators are risk averse, they may seek to reduce that cashflow volatility via forward contracting for some of their revenue.

More nuanced picture for thermal by 2032

3.8 Figure 4 shows projected demand for thermal generation in 2032. Much more expansion of the renewable base is expected to have occurred. As a result the thermal generation levels are expected to be markedly lower than in the past, or 2025.

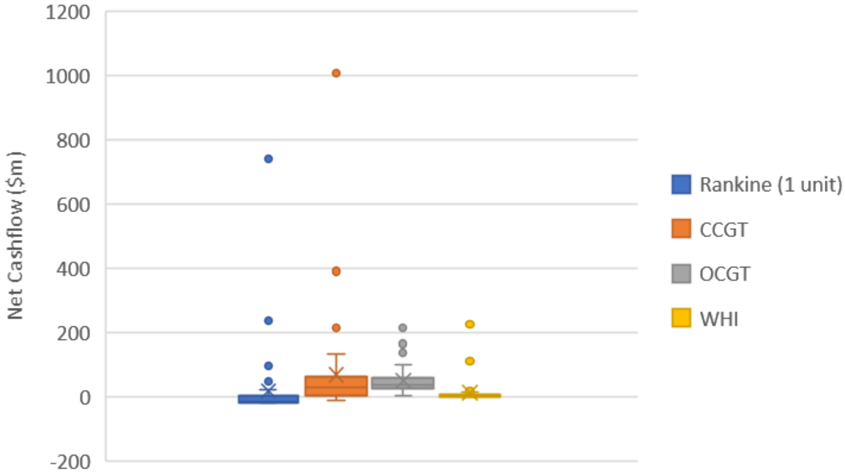
Figure 4: Historical and projected GWh by thermal plant type in 2032



3.9

3.10 **Figure 5** shows the projected impact on net cashflows for different plant types in 2032. Despite the overall reduction in the demand for thermal generation, the analysis indicates that OCGTs would remain viable under the base-case assumptions (but see later section on sensitivities). This reflects the very flexible nature of the plant and its ability to provide the increasingly valuable back-up service.

Figure 5: Net cashflows by thermal plant type – base case 2032



3.11 The position for slower-starting plant is more nuanced. By 2032 there remains some demand for slower-starting plant, but not for all the existing units. Under the base-case assumptions, the analysis indicates one CCGT would be revenue adequate and one of the three Rankine units. The net cashflow position for the remaining two Rankine units would be negative on a mean basis.

3.12 However, it is important to note that the efficient mix of slower-starting plant is sensitive to the cost of gas relative to fuel for Rankine units (whether coal or biomass). It is possible that the Rankine units might be more efficient than the CCGT in some scenarios. However, in either case, by 2032 it appears unlikely that there would be enough demand to support retention of the CCGT and more than one Rankine unit.

No clear case for investment in new thermal generation

3.13 Concept's analysis also considered the question of whether investment in new thermal plant might be desirable from an efficiency perspective in 2032. Would investment in new flexible OCGT capacity be needed to substitute for, or complement, slower-starting thermal units?

3.14 The analysis did not find investment in new thermal generation was likely to be economically beneficial in the period up to 2032.

3.15 Concept made some caveats. First, the analysis of start-up costs and operating restrictions for the slower-starting units is based on publicly available information. It is possible there is other relevant information known to thermal plant owners that is not reflected in the analysis. For example, if slow-start thermal were even less flexible than modelled, then more investment in new, more responsive plant might be efficient.

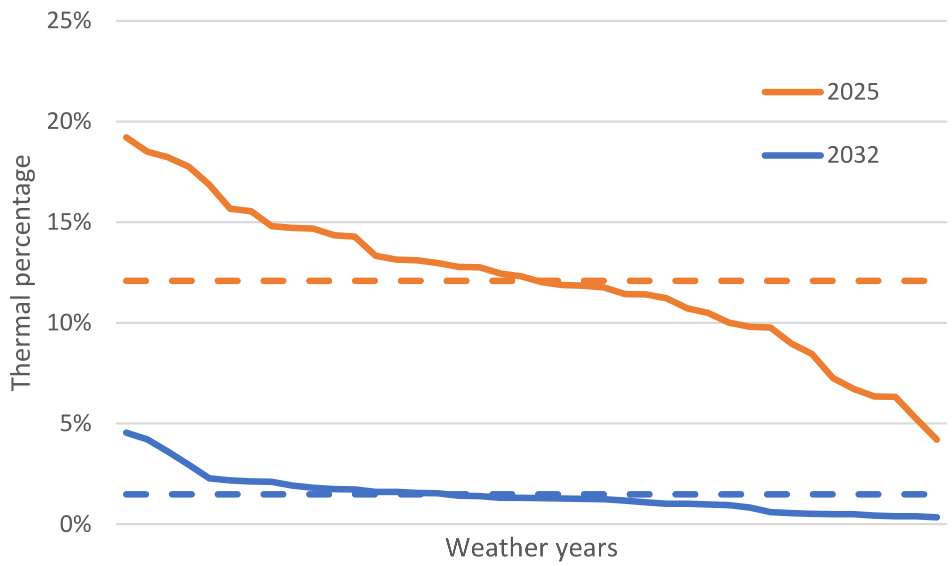
3.16 Second, the analysis focussed on potential investment in new thermal generation capacity. The analysis did not consider the potential for investment to be desirable in relation to fuel provision, for example investment in gas production or underground gas storage capacity. Such matters were outside the scope of the analysis.

3.17 Finally, the analysis incorporated the effects of short-term random plant outages on the efficient plant mix but assumed that none of the existing thermal plants suffers a major failure that renders it permanently inoperable. Were such an event to occur, that could alter the economic benefit equation for investment in new flexible thermal plant.

Effect of weather variation on thermal generation operation

3.18 As noted above, actual thermal generation levels in 2025 and 2032 are expected to be strongly influenced by weather. That is not surprising given the role of thermal generation will increasingly be confined to providing back-up services. A more subtle change centres on what that trend is likely to mean for the nature of thermal operation over time. This more subtle effect is illustrated by Figure 6 which depicts projected thermal generation percentages ranked by weather years.

Figure 6: Thermal generation percentages across weather years



3.19 Broadly speaking, dry years are toward the left-hand side of the chart, and wet years at the right. The chart shows two separate lines for 2025 and 2032 respectively. Key observations from the chart include:

(a) The line for 2025 is much steeper than for 2032. This reflects the expectation that thermal generation will provide a mix of short-term peaking and hydro-firming in 2025. Hence, thermal generation is much lower than average in relatively wet years and higher in dry years.

(b) However, by 2032 the level of thermal generation is very low across most weather years. In wet years there is little ability to reduce thermal generation because it is already low. Instead, the downward flex in generation is likely to come from increased renewable spill of wind/solar or hydro, among other things. Conversely, while thermal does not reduce much in wet years in 2032, it does increase appreciably in dry years. This is shown by the slope of the lines for 2025 and 2032 being quite similar on the left-hand side of the chart.

(c) Even in very wet years there is still a demand for thermal to provide short-term peaking generation in 2032.

Sensitivity cases and caveats

3.20 All the observations discussed above reflect Concept's base-case assumptions for new renewable development, demand growth, carbon and fuel costs etc. Although Concept has more confidence about these parameters for 2025 than 2032 (because they are closer in time), there is still some uncertainty.

3.21 In particular, the rate of new renewable development could be faster[22] than that assumed in the base case. Similarly, the rate of demand growth could differ from that in the base case.

3.22 As a cross check on these base-case assumptions, Concept compared the time-weighted average price (a model output) in the base case with the ASX futures prices for 2025. These values were closely aligned suggesting that the modelled thermal generation demand is consistent with prevailing forward-price indicators.

3.23 However, if demand growth is slower or renewable development faster than assumed in the base case, that will affect the demand for thermal back-up generation in 2025. For example, Concept considered a sensitivity case in which an additional 2,000 GWh of renewable generation is available by 2025 compared with the base case. Concept noted that the average spot prices implied by this case were appreciably lower than prevailing forward contract prices. In that sensitivity case, the need for fast-start flexible generation remained, but there was less demand for slower-starting plant. In particular, the sensitivity case showed a demand for two rather than three Rankine units.

3.24 The demand for thermal back-up generation in 2032 is less sensitive to demand growth and renewable build assumptions. This is because the base-case modelling for 2032 assumes that renewable development is linked to demand trends.

3.25 Another uncertainty that is relevant for 2025 (and to a lesser extent 2032) relates to the NZAS smelter at Tiwai. The base case assumes the smelter will continue in operation beyond the expiry of the current supply contract in December 2024. Concept analysed a sensitivity case in which the smelter is not operating in 2025. That resulted in much lower demand for thermal generation. While the demand for fast-start flexible generation remained, there was much lower demand for slower-starting generation.

3.26 Concept also considered a sensitivity case for 2032 with a sizeable additional flexibility source in the South Island, such as a smelter with flexible demand.[23] That sensitivity case indicated a modest reduction in the demand for slower-starting thermal generation. However, the demand for fast-start flexible thermal capacity did not change much.

3.27 Concept's analysis is based on public information sources. Any information known to thermal plant owners that is not reflected in the analysis could affect the results.

3.28 Finally, the analysis focussed on potential investment requirements in the electricity sector. It did not consider potential implications for fuel provision, such as in the upstream gas sector, as such matters were outside the scope of the report.

Overall observations

3.29 In summary, Concept's projections indicate:

(a) The overall downward trend in demand for thermal generation will continue over the coming decade, as thermal becomes increasingly confined to providing back-up services for a renewables-based electricity system. Whereas thermal generation averaged 14% of total supply in the last five years, by 2032 it will likely be around 1.5% of total supply.

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22 It is unlikely to be materially slower as most of the development projects in the base case are already committed.

23 As NZAS has proposed recently in contract negotiations with Meridian. Note that a large pumped-storage facility in the South Island would be expected to have similar effects.

(b) In the nearer term (to around 2025) demand for thermal generation is projected to remain significant in the base case. This reflects an expectation that the pace of renewable development will take time to catch up with electricity demand, and that the Tiwai smelter will continue to operate post 2024. Faster renewable development, lower than expected demand growth, or a reduction in Tiwai power usage would accelerate the thermal transition relative to the base-case projection.

(c) Under the base case for 2025, all thermal units not already scheduled for closure appear likely to have a revenue earning opportunity sufficient to cover their go-forward costs.[24] However, thermal units (and especially the Rankine units) would have significant volatility in their net cashflows if reliant solely on spot market revenues due to the effect of weather variability on thermal demand and spot prices. Forward contracting could reduce that level of volatility.

(d) By 2032 there is unlikely to be sufficient demand to support retention of all existing thermal units in the base case. By that date, retirement of some slower-start capacity (either a CCGT or some Rankine units) appears likely to be efficient. However, demand for fast-start back-up remains strong with continuing demand for service from all existing OCGTs.

(e) The potential for investment in additional fast-start capacity to become economic appears unlikely in the base case. Rather, a mix of existing fast-start and some slower-start thermal plant appears to be capable of meeting the demand for thermal generation until at least 2032 under base case assumptions.

3. Do you agree with the above expectation of the likely role of thermal generation throughout the transition? If not, what is your view and reasoning?

[24] 'Go-forward cost' is the term used to refer to the cash costs incurred to keep a plant serviceable, and for it to operate when required. It includes non-fuel variable operating costs, fuel costs, carbon costs and annualised stay-in-business capital costs.

4 Potential sources of thermal transition risk

4.1 This section discusses a range of the factors that could lead to disorderly thermal plant closure – i.e. for providers of thermal generation to close plant even though it has lower costs than alternative sources of back-up service and there is demand for its services from consumers.

Overview

4.2 As discussed in the previous section, thermal generation levels are expected to decline steeply over the coming decade, with residual thermal operation being confined to providing back-up services for variations in renewable supply and to mitigate other risks such as an unexpected surge in demand growth or outage on a major transmission circuit.

4.3 This will clearly present a more challenging environment for thermal generation operators, especially as the demand for back-up services will become more variable. However, by itself that change should not necessarily trigger inefficient retirement or investment outcomes. If a thermal unit is expected to provide a service (such as back-up services for renewables) whose value to consumers exceeds the cost of provision, in principle there should be sufficient financial reward for the operator to make that unit available. That reward may be in the form of expected future spot-market revenues, and/or contract sale revenues.

4.4 However, this outcome is predicated on a number of conditions:

(a) **Information** – wholesale market participants (including retailers, industrial consumers and generators) need to have sufficient information about the likelihood and consequences of possible thermal retirements/investments to make informed decisions.

(b) **Incentives** – wholesale market participants need to face incentives to act in a way that reflects consumer preferences (private incentives should align with the public interest).

4.5 The following sections discuss the extent to which potential information or incentive gaps might lead to inefficient thermal retirement/investment decisions. However, before considering those issues it is useful to recap briefly on the key factors likely to influence retention/investment decisions for back-up thermal resources. These factors are depicted in Figure 7.

4.6 Key observations include:

(a) System trends have a major impact on the extent of demand for back-up services. This is because back-up requirements are by nature a residual requirement. If growth in new renewable supply outstrips demand growth, back-up needs will shrink. Conversely, if demand grows faster than renewable supply the need for back-up services will expand. Furthermore, modest changes in aggregate supply or demand growth can have a disproportionate effect on demand for back-up services. Hence, it is important for decision makers to have robust and timely information on demand and supply trends.

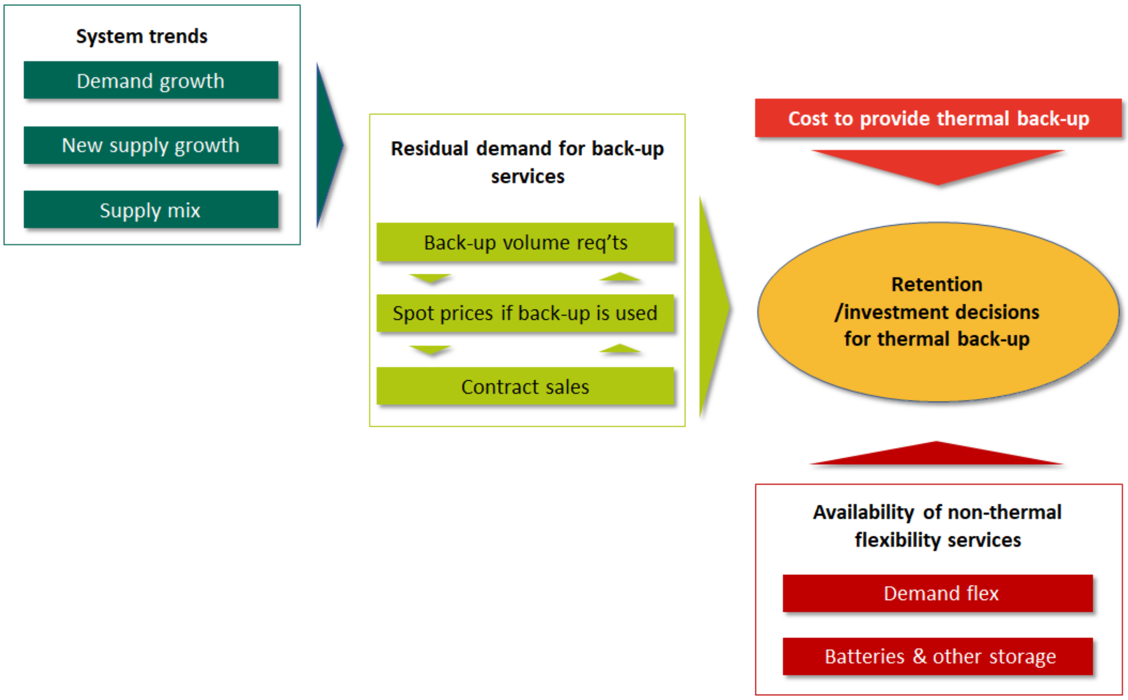
(b) The residual demand for back-up services will influence the revenue that can be earned by providers of these services. Revenues could be from sales into the spot market and/or contract market, and there are linkages between these markets. For example, expectations about the level of spot prices when back-up resource is operating will likely affect the contract market. Spot revenues are more volatile than contract revenues because they will depend upon future events that are uncertain, such as weather. Generators facing significant upfront costs to retain or develop new resources may seek contract revenues for at least part of their revenue requirements. Conversely, generators with lower upfront costs may be prepared to tolerate more exposure to spot revenues.

(c) Thermal plant is not the only source of supply for back-up services. The demand for thermal back-up services will be affected by the availability and cost of alternative flexibility sources, such as batteries and demand response.

(d) The cost of providing back-up services from thermal plant will affect thermal plant retention/investment decisions.

(e) Finally, the decision-making environment for thermal retention/investment is relatively complex with a wide range of factors influencing the financial consequences of retention/investment decisions.

Figure 7: Factors affecting retention/investment decisions of back-up thermal



Information for decision making

4.7 As noted above, the demand for thermal back-up services is sensitive to a wide range of factors because it is by nature a residual requirement. A practical illustration of this point is the large difference in thermal generation demand between Concept's base and sensitivity cases for 2025, as discussed in paragraph 3.23.

4.8 These points highlight the importance of ensuring there is a sound information base for decision makers about factors that affect demand for thermal generation.

Raw information sources

4.9 Raw data refers to the building blocks or inputs required to form views about likely future thermal demand. For example, information on the rate at which demand is growing, or about the timing of committed and planned new renewable developments. It includes information published by the Authority, MBIE, and Gas Industry Co. It also includes information published by wholesale market participants to satisfy the disclosure requirements of the Code[25] or for other purposes.

4.10 While a significant volume of raw data is available, it is useful to consider whether there are any material gaps that could be addressed, and/or whether data is available on a sufficiently timely basis.

Aggregated projections

4.11 This refers to projections of one form or another that have a direct bearing on potential future thermal generation requirements. These projections are generally compiled from the raw information discussed in the previous section. Examples in this category include:

(a) **Annual security assessments –** the Code requires the system operator to compile and publish assessments of projected energy and capacity margins and how these compare with security standards determined by the Authority. The assessments include projections over the coming decade, and typically include a range of scenarios that span (among other things) different thermal capacity assumptions.[26]

(b) **Gas supply and demand scenarios –** the Gas Industry Company periodically publishes scenario projections of future gas supply and demand, and these include projections for gas demand for power generation.[27] The most recent projections were published in 2022.

(c) **Electricity demand and generation scenarios –** MBIE periodically publishes a set of scenarios for future electricity demand and supply. These are used by the Commerce Commission to assess any major grid capital expenditure proposals from Transpower. The current set of scenarios was released in 2019.

(d) **Private forecasts** - a range of parties (e.g. broking firms, Energylink) prepare projections for clients on a fee basis. This information is typically based on public data but contains additional analysis and interpretation.

4.12 While a range of public projections are available, it is useful to consider whether the information coverage could be improved for making decisions in relation to thermal transition, whether information could be presented in a more useful way, and/or whether information is sufficiently timely.

Forward-market price signals

4.13 Market prices for forward electricity contracts can provide information that is useful for making longer-term decisions in relation to thermal transition issues. For example, contract prices may provide information about the likelihood of premature retirement, assuming that plant operators' decisions are influenced by contract prices.

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25 See clause 13.2A of Code

26 See www.transpower.co.nz/system-operator/planning-future/security-supply-annual-assessment

27 See www.gasindustry.co.nz/our-work/work-programmes/gas-supply-and-demand/#gas-supply-and-demand-projections

4.14 The Authority currently publishes information on baseload futures contract prices for a number of years into the future.[28] This information is updated each business day and shows prices for quarters (or months for nearer-term contracts) for a reference node in each island. The Code also requires wholesale participants to disclose certain information about wholesale contracts they execute on a bilateral basis.[29]

> **4. What (if any) improvements could be made to information to aid decision makers in relation to thermal transition risk?**

Incentives on decision makers

4.15 As noted earlier, outcomes will not be optimal unless decision makers have incentives to act in the wider public interest. In this context, the term 'incentive' is used broadly to encompass rewards for positive actions, or penalties (disincentives) for negative actions. The following sections discuss areas where a misalignment of incentives could lead to decisions that don't reflect long-term consumer interests.

Spot prices

4.16 Under current market arrangements the incentive on all suppliers (including thermal generators) to make resources available is ultimately tied to spot prices. The incentive can be in the form of expectations of future revenue earned from spot market sales. Alternatively, it can be from the sale of contract products that insulate buyers from spot price volatility.

4.17 In both cases for incentives to be efficient spot prices must be able to reflect the value that consumers place on reliable supply. When the system is extremely tight (or there is a supply shortage), spot prices would be expected to be very high, to reflect the value that an incremental unit of supply would have to consumers. If spot prices did not reflect that value, resource providers (including thermal generators) would have less incentive to make additional supply available.

4.18 Looking ahead, forecasters[30] generally expect an increase in the frequency of relatively short-duration spot-price volatility to occur. This is because the system is expected to become more sensitive to shorter-term weather fluctuations, such as successive days of very low wind/solar generation. These events happen relatively frequently but do not last long. By contrast, the main risk in the past has been so-called dry years. These occur infrequently, but when they happen spot prices can be elevated for many weeks or even months.

4.19 Naturally, spot prices will tend to attract more scrutiny when they are elevated. However, if physical system conditions are genuinely tight, it is important that this is signalled in

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28 See www.emi.ea.govt.nz/Forward%20markets/Reports

29 See Subpart 5 of Part 13 of the Code

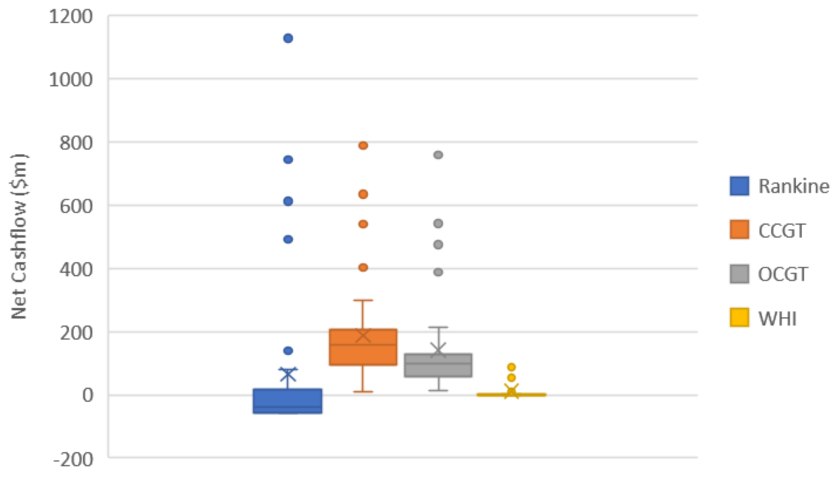
30 For example see https://www.ea.govt.nz/documents/1005/01-100-Renewable-Electricity-Supply-MDAG-Issues-Discussion-Paper-1341719-v2.4.pdf

spot prices. Conversely, it is also important to ensure that instances of high spot prices reflect genuine supply scarcity, and not an abuse of market power.

4.20 Providers of back-up resources, such as thermal generation or batteries, will be especially sensitive to the level of spot prices when the system is tight. This is because their spot energy sales will be largely confined to such periods. Likewise, the value to buyers of hedge contracts will be sensitive to spot price expectations during periods of tight supply.

4.21 This observation is illustrated by Figure 8[31] which shows the average net cashflow projected for different thermal plant types in 2025. The crosses indicate the mean net cashflow across the 40 weather years analysed in the model. These crosses can also be interpreted as the net cashflow position if operators sell forward contracts at the expected value of future spot prices (i.e. there is no premium or discount in contract prices). In all cases the mean net cashflow position is positive, suggesting that a decision to retain the plant in operation would be cashflow-positive for owners.

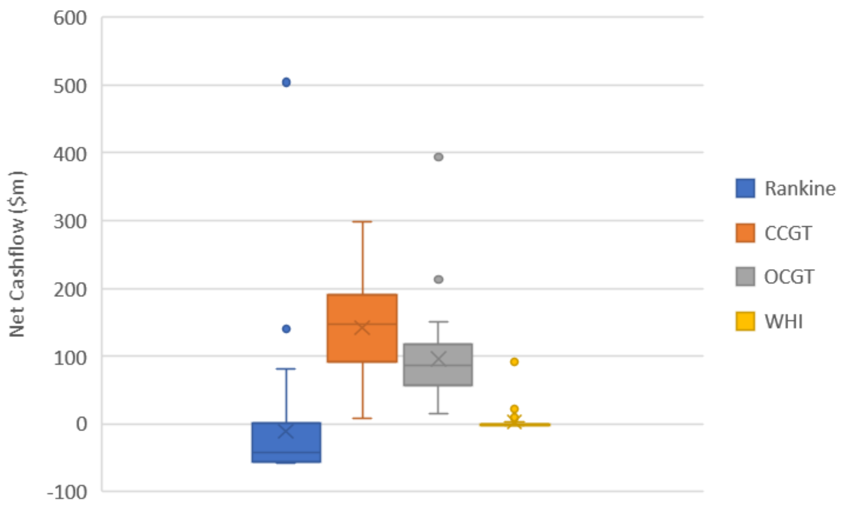
Figure 8: Net cashflows by thermal plant – base case 2025



4.22 However, mean cashflows are sensitive to outcomes in a handful of extreme weather years (indicated by the dots). If spot prices in such years were not allowed to reflect efficient levels, that would materially erode mean cashflows for some thermal plant. This is illustrated by Figure 9 which shows the effect on mean cashflows if the top 10% of cashflows (four weather years) are omitted from the distribution.

31 This chart is shown earlier as **Error! Reference source not found.** and is reproduced here for ease of r eference.

Figure 9: Net cashflows by thermal plant in 2025 – excluding 4 driest years



4.23 Figure 9 shows that the modelled mean net cashflow for Rankine units would be negative, were spot prices not able to rise to efficient levels during periods of low inflows.

4.24 Current arrangements for determining spot prices are intended to generate efficient price signals at all times, including during periods of very tight supply. The adoption of real-time pricing in late 2022 was designed to ensure spot prices better reflect prevailing supply and demand conditions. Also, new demand-side participation mechanisms (dispatchable demand and dispatch notification) were implemented on 27 April 2023. These mechanisms enable the demand side to signal the value of demand response and realise that value through contracts with exposed purchasers. Real-time pricing also includes an administered scarcity-pricing mechanism[32] to signal the value of energy in any periods of actual reserve or supply shortfalls.

4.25 To detect and deter the abuse of market power, the Code includes trading conduct rules, which are backed by active monitoring by the Authority. The Code's trading conduct rules are designed to promote competitive behaviour in the spot market and provide a framework for assessing relevant participant behaviour.

4.26 In summary, the Authority recognises the critical role that efficient spot prices need to play to incentivise efficient thermal transition decisions. As far as the Authority is aware, there are no mechanisms in current market arrangements that would artificially distort spot prices and erode suppliers' incentives to make efficient decisions in relation to provision of back-up resources. However, it is important to ask market participants whether they are aware of any features of current spot market arrangements that would undermine incentives to make efficient decisions in relation to back-up resources.

5. Are there any aspects in current spot market arrangements that are likely to undermine incentives to make efficient decisions in relation to back-up resources? If so, what are they?

32 Spot prices are based on a pre-determined formula (rather than bids and offers from market participants) if insufficient supply is offered to satisfy all demand and maintain normal reserve margins.

Forward contracting incentives

4.27 Paragraph 4.13 discussed the availability of forward price *information* as a factor that could potentially affect the ability to make efficient thermal retention/retirement decisions.

4.28 A related but distinct issue is whether participants have appropriate *incentives* to enter into forward contracts.[33] Forward contracting is likely to be important for mitigating thermal retirement/investment risks. This is because thermal generators' spot revenues will become increasingly volatile over the transition, for the reasons noted earlier. Entering into forward contracts will reduce the variability in annual revenue due to weather fluctuations.

4.29 Likewise, wholesale purchasers will face greater volatility in their purchase costs in the absence of forward contracts. This increases the risk of a wholesale purchaser defaulting on its spot market obligations, all other things being equal. That could have flow-on impacts, such as the disruption for end-consumers if their retailer were to cease operation. A higher risk of purchaser defaults will also make thermal generators more wary of relying on spot revenues to underwrite retention/investment decisions – since there would be an increased risk of not being paid.

4.30 For all of these reasons a substantial level of forward contracting is expected to create a more predictable and stable environment, which in turn should support an efficient thermal transition.

4.31 Wholesale purchasers and sellers have strong natural incentives to forward contract to reduce exposure to financial risk arising from spot price volatility. This may explain why the New Zealand system has historically seen a significant level of forward contracting – via generators contracting with end users (i.e. vertical integration[34]) and via exchange traded or bilaterally negotiated contracts.

4.32 Looking ahead, there is a question about how those incentives will be affected by increasing spot-price volatility. One possibility is that it will increase the incentive on wholesale purchasers and generators to forward contract, particularly if periods of volatility occur more frequently. On the other hand, for wholesale buyers[35] the incentive to contract could be reduced if they perceive an appreciable likelihood that high spot prices will be politically unsustainable during periods of tight supply or shortage events.

4.33 If this perception were to become widespread, it could create a negative feedback loop. This is because lower forward contracting would increase the proportion of wholesale purchasers exposed to spot prices. A larger number of wholesale purchasers with significant exposure to spot prices could increase pressure on politicians to intervene, which in turn could reduce contracting incentives, and so on. If an intervention were to occur, that could help those purchasers currently exposed to spot prices but would penalise other parties that had entered into contracts ahead of time to manage their financial risk. That in turn would likely reduce the incentive to enter into future contracts.

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33 The availability of contracts to wholesale participants is also a critical issue. That is discussed further in the next section.

34 Vertically integrated generators achieve forward contracting via contracts with retail consumers, rather than with wholesale market participants.

35 Wholesale buyers will include large industrial consumers of electricity and retailers who purchase wholesale electricity on behalf of end-consumers.

4.34 In part to address these types of concerns, the Code contains so-called stress-testing provisions.[36] These require certain wholesale market participants to apply standardised stress scenarios to their electricity market positions. It also requires parties to report the results to a registrar appointed by the Authority and provide a declaration that decision-makers in the organisation have considered the stress test results.

4.35 The Code provisions are designed to ensure participants are actively considering the impact of potential stress events on their businesses, while still leaving responsibility for risk management decisions firmly with participants.

6. Do current arrangements provide balanced incentives to conclude forward contracts to manage thermal risks of transition appropriately? If not, what are the reasons for your view?

Availability of forward contracts

4.36 As discussed in the preceding section, active forward contracting by participants that need back-up services from thermal generation (such as retailers or hydro generators) is likely to be a key element of a smooth transition. For this to occur it is important that purchasers have access to sufficient forward contracts, and that these are available on reasonable terms (including prices).

4.37 Dealing first with the sufficiency issue, the Authority is not aware of any reason to expect a shortfall in the ability to provide such contracts. This is because projections by Transpower and others indicate there should be sufficient generation physically available to meet energy and capacity standards for the next few years.[37] This suggests that there should be the physical base to support the sale of contracts to meet likely demand. We also know that contracting can occur (and has occurred) using exchange-traded products, or on a bilateral basis using so-called over the counter (OTC) products, as well as via vertical integration.

4.38 Turning to the issue of contract terms, this is a more difficult issue to assess as it requires judgements about a range of factors including prices. The Authority does not have sufficient information to form a clear view on this front. As part of the Wholesale Market Review, the Authority has proposed that work should be undertaken to improve the electricity contract disclosure system.[38]

4.39 While the Authority does not have sufficient information to form a definitive view, it notes that there is a relatively long history of participants entering into back-up contracts

36 See https://www.ea.govt.nz/documents/2012/Stress_testing_regime.pdf

37 The focus is on the next few years because there is more certainty about demand and supply options in this period. Further into the future there is less certainty about both demand and supply. See footnote 26 as an example.

38 See https://www.ea.govt.nz/documents/2243/Promoting-competition-in-the-wholesale-electricity-market.pdf. A similar proposal has been made by the Authority's Market Development Advisory Group – see https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf

underpinned by thermal generation. For example, parties have entered into a series of so-called swaption contracts since at least 2009.[39]

4.40 Furthermore, public statements indicate flexible contracts backed by thermal generation are continuing to be executed as indicated by Table 2.

Table 2. Recent large contracts related to back-up services

Sell-side	Buy-side	Type	Announced	Term	Volume (GWh/yr)
Nova	Meridian	Call	Dec 2021	2023-27	235
Contact	Meridian	Swaption	Aug 2022	2023-24	150
Contact	Meridian	CFD	Aug 2022	2023-24	294
Genesis	Various	Market Security Options	Feb 2023	2023-24	Undisclosed

Source: Company announcements

7. Do current arrangements ensure reasonable availability of forward contracts related to back-up services – such as dry year cover? Please explain your reasoning.

Treatment of forced power cuts in retail supply contracts

4.41 From an efficiency perspective, the optimal outcome is for back-up resources on the system to reflect the level that consumers are willing to pay for. Achieving this outcome is more likely if consumer preferences are reflected in the forward contracts they have with suppliers.

4.42 In the case of large consumers, they can contract directly in the wholesale market with suppliers. Furthermore, large consumers who are willing to reduce their demand when system conditions are tight (and spot prices are elevated) can reflect those preferences in their contract decisions.

4.43 For smaller consumers who contract with retailers (who in turn contract in the wholesale market or are vertically integrated) the position is less clear-cut. Most of these electricity users purchase their power from a retailer on a variable volume contract. Any forced demand curtailment will impose a cost on the affected consumers (from reduced usage), but the relevant retailer may not face a cost. Indeed, a retailer may even benefit because reduced consumption by its customers will lower its wholesale purchase costs.

4.44 The underlying issue is that there is a lack of clarity about the level of reliability that is implicit in the retail contract. On one perspective, it could be argued that consumers are purchasing a 'firm' level of supply[40] and expect retailers to reflect that in their wholesale contracting decisions. An alternative perspective is that consumers are purchasing a service with less firmness, and that any forced power cuts due to wholesale level shortfalls are priced into retail contracts.

39 For example see www.nzx.com/announcements/281407. In essence, swaption contracts provide for one party to pay an upfront option fee in return for a right to call for swap which will (if called) protect the buyer against high spot prices.

40 The term 'firm' is used here to refer to wholesale supply-related issues. Obviously, there can be non-wholesale events which interrupt supply, such as loss of distribution network service due to storm damage. Such non-wholesale causes would fall outside the definition of firmness used in this context.

4.45 If retailers and their customers share a common perspective on the degree of firmness in retail supply contracts, then consumer preferences should be reflected in retailers' wholesale contracting decisions. However, if retailers and consumers do not have a common perspective, that could result in consumer preferences about cost/reliability trade-offs not being reflected in retailers' contracting decisions, and in turn make it less likely that plant retention/investment outcomes will reflect consumer preferences.

8. To what extent do current arrangements create potential for misaligned incentives between retailers and consumers in relation forward contracting with adverse impacts on thermal transition risk? Please explain your reasoning.

Clarity around ripple control volumes and usage rights

4.46 As shown in Figure 7, the level of back-up services demanded from thermal generation will be influenced by the availability of back-up from other sources. While the volume and cost of those alternatives can never be entirely certain, it is desirable to remove uncertainty around those issues wherever practical.

4.47 A potential concern in this context is uncertainty over the volume and usage rights for discretionary ripple control of hot water heating demand. Some of this demand-response capability is offered into the wholesale market in the form of interruptible load but the balance is not.

4.48 If a very tight supply situation arises in real-time, the system operator will ask networks to reduce any discretionary demand, and most will respond by reducing any hot-water load not used for interruptible load. This response can be equivalent in size to a large thermal unit.[41]

4.49 Under current arrangements, it is not always clear how the rights to trigger ripple control have been defined and allocated between end-use customers, retailers, distributors and Transpower.

4.50 Furthermore, there is poor clarity on both the amount of resource available each trading period, and in what situations it will be used. It appears that these uncertainties could have a significant effect on the residual flexibility demanded by the system, including from thermal generation.

4.51 As outlined in the decision paper – driving efficient solutions to promote consumer interests through winter 2023 – the Authority has decided to pursue for potential implementation an option that would require at least some distributors to bid into the wholesale energy market the discretionary demand that would be available to the system operator in very tight situations. This discretionary demand would be required to be bid at a very high scarcity price. The Authority will review this option through winter 2023 and may decide to implement it if it adds value.

9. To what extent do current arrangements relating to use of ripple control in periods of tight supply affect thermal transition risk? Please explain your reasoning.

41 Transpower estimated it was around 300 MW on 23 June 2022.

Lumpiness of thermal retirement/investment decisions

4.52 As noted earlier, active forward contracting by wholesale purchasers and thermal generation owners should help to ensure an efficient thermal transition. A factor that may complicate forward contracting is the 'lumpiness' of some decisions. Lumpiness can take three different forms, all of which may present some potential challenges.

4.53 The first aspect of lumpiness refers to the large MW size of some units when compared to the New Zealand system. This is particularly the case for the combined cycle and Rankine units which are 250 MW or greater in size. Obviously, retention and retirement decisions need to be made at a full unit (or even a station) level. The large size of the units relative to the system may make it harder to achieve optimal outcomes.

4.54 In particular, it may make associated contracting more challenging. Contract sellers naturally prefer a higher price, recognising it cannot exceed the cost of the buyer's next best alternative (likely to be the cost of a new plant or equivalent). Conversely buyers will naturally prefer lower a price, recognising it must at least cover the seller's avoidable costs (excluding any return on sunk investment). In principle, any contract price struck between the two bookends should produce an efficient retention decision. However, that efficient price range may be quite wide where decisions are being made about whether to retain existing large units. That in turn would give the parties strong incentives to haggle over where to set the contract price within that efficient range.

4.55 To this end parties may try to improve their negotiating position through external appeals to media, regulators and policy agencies. For example, thermal unit owners may emphasise the threat of impending closures in the absence of acceptable contracts. On the other hand, wholesale buyers may appeal to external authorities to prohibit closures or to limit contract prices. Attempts to create external pressure on negotiating parties have been evident in Australia in recent years.

4.56 On a related front, closure announcements may reset expectations and enable parties to reach agreements when earlier negotiations did not succeed. This may have been the case in New Zealand in 2015 when Genesis announced the permanent closure of the Huntly Rankine units from December 2018.[42] Subsequent to that announcement, Genesis signed agreements with a number of wholesale buyers and decided to extend the operational life of the units.[43]

4.57 In making the above observations we are not suggesting parties in Australia or New Zealand have acted in bad faith. Rather the point is that the value at stake means that parties have incentives to test each other's positions, including via public announcements.

4.58 We also note that even when negotiations lead to an (apparently) poor outcome, this is not necessarily the end of the road. As indicated above, closure decisions which appear final have sometimes been reversed in the past. Furthermore, closure decisions only become irreversible when plant is demolished or rendered unserviceable.[44]

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42 See Genesis Energy announces Huntly Rankine units retirement - NZX, New Zealand's Exchange

43 See www.nzx.com/announcements/281406

44 Mothballing of thermal plant is another option. This involves work to preserve the plant (e.g. emptying boilers and filling them with inert gas). Mothballing allows a plant to be stored for possible future use, but typically with a long recall period.

4.59 The second aspect of lumpiness relates to the possibility of plant requiring very large upfront expenditure. For existing plant, the main lumpy item (construction cost) is already sunk and should not therefore affect retention/closure decisions. However, even for existing plant lumpy expenditures can arise. For example, plant owners may need to undertake significant work to extend plant life (such as refurbishment of gas turbines). Larger expenditures typically need more years of operation and sales to recover the upfront costs. This means owners must forecast spot prices over longer periods, and/or contract further forward. Both of these can be challenging, especially for a system in transition. Conversely, if units require fairly steady expenditure from year to year to remain operable, the planning horizon ought to be shorter and would presumably be easier for thermal generators and wholesale purchasers to manage.

4.60 As far as the Authority is aware, the only thermal unit currently facing a large lumpy expenditure requirement is the Taranaki combined cycle (TCC) unit. The plant owner (Contact) has announced that extending the plant life beyond around 2024 is likely to cost approximately $80m,[45] and that this is unlikely to be economic.

4.61 Other thermal units also face stay in business expenditure to remain operable. However, the attached report from Concept (compiled from public data) suggests that the expenditure profile for other units is likely to be substantially less than for TCC on a per unit basis, at least for the foreseeable future. Similarly, the Concept analysis suggests that investment in new flexible thermal capacity is unlikely in the near term (noting it would otherwise have raised a significant lumpy upfront expenditure issue).

4.62 These factors suggest that the lumpiness in relation to expenditure requirements may be manageable at least for the next few years, although the position later in the decade is less clear-cut.

4.63 The third source of lumpiness arises from the fact that ownership of thermal units is spread across many parties. There are likely to be benefits in coordinating some decisions across the various thermal units. For example, simultaneous uncoordinated retirement of multiple generators is unlikely to be desirable. Similarly, there may be some benefits from coordinating fuel management.

4.64 Contracting between different thermal generator owners is likely to enable some coordination efficiencies. For example, some thermal generators have in the past arranged tolling agreements to better optimise how demand is covered.[46] Having said that, it may be challenging to manage some coordination issues via contracts. For examples, issues that require cooperation of several parties (e.g. generators and fuel suppliers) may be harder to handle via contracts.

4.65 Similarly, contracts are more workable where the performance required of counterparties can be readily defined and then monitored. Sometimes standards can be hard to define, or it may be difficult to monitor adherence to a contract. In such cases contractual approaches to ensure coordination may less workable.

4.66 While lumpiness can be a problem for the reasons mentioned above, the Authority's initial work indicates it is not likely a problem at present.

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45 Statement by Contact Energy as reported by Energy News on 16 August 2021.

46 See Contact Energy operating report, 2019.

10. Do you agree with the Authority's view above that lumpiness does not (at present) threaten to disrupt an orderly thermal transition? If so, or if not, please explain your reasoning.

Selective support mechanisms outside the wholesale electricity market

4.67 Thermal transition risk is likely to be lower if renewable and thermal generation compete in, and are paid from, a common revenue pool. This is because a common revenue pool provides a natural coordination mechanism for generation entry and exit decisions. For example, as new renewable generation comes online that will tend to reduce the revenue opportunity available for thermal generators (especially baseload operation), all other things being equal. Conversely, if development of new renewables is delayed or demand growth surges unexpectedly, there is likely to be additional revenue to keep thermal generation (or other back-up resources) available for a longer period in the transition.

4.68 In some countries there is substantial financial support for renewables which is paid in addition to, and outside of the wholesale electricity market. Mechanisms of this type may reduce prices in the wholesale electricity market below the level necessary to sustain efficient thermal capacity.[47] If that occurs (or there is an expectation it is likely), there can be a need to create a separate support payment for thermal units. Coordination of the rate of renewable entry and thermal exit is then heavily influenced (or even governed) by the various support mechanisms rather than solely by wholesale market signals.

4.69 In New Zealand, all generation types currently rely on the wholesale market as their common revenue source. There are no subsidies for renewable (or thermal) generation types paid outside of the wholesale market. Instead, New Zealand has adopted a broad-based emissions trading scheme with an associated carbon price. Participants in the wholesale electricity market can take account of the carbon price in their offers and bids, and hence this carbon price signal is internalised within the wholesale electricity market.[48]

4.70 Overall, based on current information, we have not identified any selective support mechanisms paid outside the wholesale market that are likely to cause coordination issues. However, we would like to understand wholesale participants' views on this matter.

11. To what extent are there any selective support mechanisms paid outside the wholesale market that could pose a challenge to achieving an efficient thermal transition? Please explain your reasoning.

47 This is also referred to as the 'merit order' effect. For example see Simshauser, P., 2018, On intermittent renewable generation and the stability of Australia's National Electricity Market, *Energy Economics,* vol. 72, May 2018, p1-19.

48 The Authority notes that this may raise other issues such as concerns about value transfer to owners of existing renewable generation – see for example www.climatecommission.govt.nz/our-work/advice-to-government-topic/nz-ets/our-advice-on-the-nz-ets/nz-ets-unit-limits-and-price-control-settings-for-2023-2027/.

Potential emergence of unpriced wholesale ancillary services

4.71 An issue that has arisen in some countries is that thermal generation was providing a service that was distinct from energy provision which was not being explicitly recognised or rewarded by existing market arrangements. The absence of an explicit reward did not matter in the past because the non-energy service was being provided as a free by-product of thermal energy generation. However, as the system changes and thermal generation levels decline, the demand for the unpriced service became apparent.

4.72 A related but distinct issue is whether current market arrangements provide sufficient differentiation in the reward for providing *energy* of different levels of firmness. In principle, the ability of spot prices to vary by half-hour and location means that providers of flexible dispatchable energy will earn a higher average price for their output than (say) a supplier whose production is uncontrollable. However, this assumes spot prices can move to reflect changes in the value of energy to the system. Hence the Authority has posed the questions at the end of paragraph 4.26.

4.73 Returning to non-energy services, an example is the provision of inertia. When synchronous generation (such as thermal and hydro) is operating it provides inertia[49] to the system as well as energy. Some other resources do not typically provide inertia, though they can be built to provide synthetic inertia. These are known as inverter-based resources (IBR) and include most solar and wind generation and batteries. As the proportion of supply from IBR increases, there is a possibility that inertia will become scarce unless there is an explicit signal to reward its provision.

4.74 Inertia is used as an example here, but the more general point is that it is important to consider how the system will change over time – especially in relation to ancillary services. This issue has particular relevance for thermal retirement/retention decisions if there are services being provided by thermal generation that are not being rewarded by current market arrangements.

12. To what extent is thermal generation providing a service that is needed but not explicitly priced and rewarded? Please explain your reasoning.

Effect of non-financial factors on decision makers

4.75 The preceding discussion assumes that owners of thermal plant will make retirement and investment decisions largely based on financial factors. An alternative view is that decisions could be principally driven by non-financial considerations – in particular a desire to address environmental concerns from shareholders and/or customers.

4.76 Under the second view thermal transition risk would likely be higher, as there is a possibility that some generators could feel the need to retire thermal plant even though it was the lowest cost option to provide needed back-up services (even after accounting for carbon charges) and consumers (via their agents) were willing to contract for its retention.

4.77 Clearly, understanding which of the above decision-making lenses best describes thermal plant owners is a critical issue. Our sense is that decision makers do give careful

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[49] For an explanation of inertia in electricity systems see www.nationalgrideso.com/electricity-explained/how-do-we-balance-grid/what-inertia.

attention to non-financial factors, but that financial considerations are likely to remain a reasonable predictor of behaviour.

4.78 This view is based on a range of factors including:

(a) Successive governments have introduced mechanisms to align financial and emission-related considerations for decision makers. For example, the emissions trading scheme and the establishment of the independent Climate Change Commission to provide carbon price signals that are consistent with the government's climate policy objectives. In the same vein, the government has introduced new binding rules for climate-related disclosures from 1 January 2023. Among other things, these require listed companies to report on the indirect greenhouse gas emissions that occur in their value chains, including upstream and downstream "fuel-related and energy-related activities".[50] This disclosure regime should give a more complete picture of emission footprints than existing arrangements which concentrate largely on direct sources of emissions.

(b) Decision makers are likely to consider the full range of non-financial factors when considering thermal transition issues, not just emissions-related matters. In particular, the effect of retirement decisions on reliability of electricity supply is likely to be a factor parties would give careful consideration, in addition to other matters.

(c) Finally, if an organisation felt a compelling need to exit from thermal generation to address environmental imperatives, plant closure is not the only option available to it. If a plant was genuinely still needed for the transition to ensure reliable supply, it seems likely that sale of the plant would be considered by an owner.

13. To what extent will thermal retirement/investment decisions be driven by non-financial factors? Please explain your reasoning.

Any other factors that could undermine efficient thermal transition

4.79 The preceding sections discuss factors identified by the Authority that could cause information or incentive gaps and undermine an efficient thermal transition.

14. What (if any) other factors could undermine an efficient thermal transition? Please explain your reasoning.

50 See www.xrb.govt.nz/dmsdocument/4770

5 High level options to address thermal transition risk

5.1 This section discusses a range of options to address thermal transition risk. It also sets out the Authority's preliminary views on whether any action is necessary at present. The Authority welcomes feedback on this, the options identified, and any other alternatives that should be explored. This information will inform any further work by the Authority on thermal transition issues.

5.2 The Authority's work to date, and the results of the quantitative analysis by Concept, indicate there are presently low levels of investment-related thermal transition risk. The Authority intends to monitor the level of these risks as the transition continues. The reasons for discussing options to address thermal risk at this stage are as follows:

(a) To note that some options to mitigate thermal transition risks are already being progressed in terms of other work by the Authority[51];

(b) To mention that some options (e.g., strategic reserves and capacity mechanisms) are unlikely to be progressed as they have been evaluated and not recommended for further consideration in related work by MDAG52 and the Authority; and

(c) To consider appropriate options if thermal transition risks increase in future.

5.3 As noted above (and in section 2), the Authority is progressing work on other fronts (notably the Wholesale Market Review and work on winter 2023) to update the wholesale market and ensure it supports a renewables-based system. Some options discussed below have already been raised in those other workstreams. Nonetheless they are canvassed here where they have direct relevance to thermal transition risk.

Criteria for assessing high-level options

5.4 Although initial work indicates there is a low level of thermal transition risk, the Authority would welcome feedback on this point. The Authority has evaluated several options for potential implementation should thermal transition risks increase significantly in future.

5.5 The objective is for options to be in the long-term interests of consumers (i.e. for their long-term benefit, in terms of the Authority's statutory objective). We also want to ensure that any changes to reduce thermal transition risk will align with New Zealand's decarbonisation goals.

5.6 With these factors in mind, we have evaluated options based on the extent to which they:

(a) Improve the information available to customers and operators to make efficient contracting and commitment decisions.

(b) Better align the incentives on purchasers and operators with the interests of end-use consumers.

(c) Risk unintended harmful side-effects for consumers, such as weakening current incentives to make investments in back-up resources or contracting to provide back-up services.

(d) Can be modified or removed if they do not provide net benefits.

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51 See https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

52 See https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf

(e) Align with the aim of transitioning to 100% renewables, including the target for 50% renewable energy.

Overview of options and applicability to each risk

5.7 Table 23 provides an overview of the options that have been considered by the Authority, and a preliminary assessment against the criteria discussed above.

5.8 In the final column is the status of each option – some options are being progressed in terms of the Winter 2023 work; some are potential options should the risks of disorderly thermal transition increase; and other options are not recommended.

Table 3. Overview of options and preliminary assessment

Option	Impro-ves inform-ation	Improves incentives	Risk of unintended harmful effects	Ease of modification or removal	Alignment with transition to 100% renewable	Current status of option
A - Provide more information to assist decision making	✓	-	Lower	Easy	✓	Mostly implemented in Winter 2023 work
B - Review administered prices to apply in shortages	-	✓	Moderate	Easy	✓	Will be reviewed in wholesale policy work
C - Modify stress testing mechanism	-	✓	Lower	Easy	✓	Could consider if risk increases
D - Clarify availability and use of ‘discretionary demand’ control	✓	✓	Lower	Easy	✓	Implemented in Winter 2023 work
E - Require retailers to make compensation payments to customers affected by forced power cuts	-	✓	Moderate	Moderate to Difficult	✓	Not recommended (will be reviewed in post-Winter 2023 work)
F - Introduce new ancillary service product	-	✓	Moderate	Moderate to Difficult	✓	Will be pursued in post-Winter 2023 work
G - Introduce minimum notice period for plant capacity reductions	✓	?	Moderate	Easy	✓	Could be considered if risk increases
H - Introduce capacity mechanism	-	✓	Higher	Difficult	?	Not recommended
I - Introduce contingent contracting obligation	-	✓	Moderate to Higher	Moderate	✓	Not recommended
J - Introduce strategic reserve	-	?	Higher	Difficult	?	Not recommended
K – Pre-arrange short-term emergency reserve	-	?	Moderate	Difficult	✓	Not recommended

A – Provide more information to assist decision making

5.9 As discussed from paragraph 4.5, a range of information is currently available to help participants to make decisions about thermal plant retention/investment and related matters.

5.10 Nonetheless there appear to be some areas where information could be improved, either in coverage or timeliness or both. Potential areas to address include:

(a) The demand for back-up resources is quite sensitive to changes in the supply/demand outlook. However, there is relatively little public visibility about new projects (demand, supply or battery storage) in the development pipeline, unless a developer chooses to make announcements about its intentions. Furthermore, while Transpower publishes Annual Security Assessments which provide information on the overall security margin outlook, the assessments present many scenarios, some key assumptions are not disclosed to preserve confidential sources and the outlooks are updated only annually. In summary, the lack of clear visibility about the development pipeline contributes to increased uncertainty about the supply / demand outlook. As part of the Wholesale Market Review, the Authority has already proposed changes to address this issue. In its decision paper the Authority has invited MBIE to produce an Annual Electricity Generation Investment Opportunities report, targeting international developers, with input from NZ Trade & Enterprise, Transpower, the Electricity Authority, Overseas Investment Office, and Ministry for Environment[53] A related possibility would be to publish information along the lines of that available in the Australian National Electricity Market (NEM). This presents detailed information on existing, committed, anticipated and proposed generation/battery storage capacity for the next ten years. It is updated quarterly or more frequently as required.[54]

(b) The overall demand for back-up resources will be influenced by the degree of correlation between periods of low solar, wind and hydro inflows (among other things). The more tightly these are correlated, the greater the demand for back-up resources and the less the correlation, the lower the need for back-up. Historically, significant effort has been applied to capturing and publishing hydro inflow data to help participants with their hedging, investment and other decisions. However, there is less publicly available information about solar and wind patterns, especially the degree of correlation with hydro inflows. This is an example of an area where the provision of more raw data could be beneficial to decision-makers.

5.11 As part of Winter 2023, the Authority has implemented several options that will provide more information and likely assist decision making.[55] These are the winter 2023 options : A (provide better information on headroom supply stack), option B (provide forecast spot prices under demand sensitivity cases) and option D (system operator review of wind offers based on external forecast). These should all provide more information on the supply and demand outlook.

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53 See https://www.ea.govt.nz/documents/3017/Decision_paper_promoting_competition_through_the_transition.pdf

54 See https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2023/nem-generation-information-feb-2023.xlsx?la=en

55 See https://www.ea.govt.nz/projects/all/managing-peak-winter-electricity-demand/

5.12 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option would improve information availability, have no effect on incentives, and would be relatively easy to modify or unwind. It also appears to have low risks of unintended adverse consequences and would align with the aim of 100% renewable supply.

5.13 To the extent that this option has not already been addressed by the Authority in terms of the Wholesale Market Review and Winter 2023 work, it could be pursued if the risk of disorderly thermal plant closure were to increase.

B – Review administered prices to apply in energy or reserve shortages

5.14 As discussed in paragraph 4.16, it is important for spot prices to reflect accurately the physical balance between supply and demand at each location and moment in time. In particular, to minimise thermal transition risk, spot prices must properly signal the value of electricity when the system is tight – otherwise the incentives to provide back-up resource (such as flexible thermal plant) will be artificially suppressed.

5.15 The Authority's recent paper on Winter 2023[56] noted the introduction of real-time pricing should assist in this area. It also noted that spot prices are administered, rather than being set based on bids and offers, when there are supply shortfalls for energy or reserves. The administered price values have been set at levels intended to reflect the cost of involuntary load reduction to consumers (if demand is curtailed) or reduced system security (if there is insufficient reserve). The basis for these values, however, has not been fully examined since 2011, although the way they apply was reviewed more recently as part of real-time pricing.

5.16 The Authority recognises that reviewing the values is a challenging task because of the complexities involved. For this reason the Authority noted that it would be important to review these values in a considered way and including a consultation process. The Authority will likely explore such a review as a part of its work program for further development after winter 2023.

5.17 The Authority's preliminary assessment is that this option could improve incentives, appears to have moderate risks of unintended adverse consequences and would align with the aim of 100% renewable supply.

5.18 As these administered prices will be reviewed as part of the Authority's work programme, this option will not be pursued for the thermal transition work.

C – Modify stress-testing mechanism

5.19 As discussed in paragraph 4.34, the current stress-testing mechanism is designed to reinforce the obligation on participants to manage their risks via forward contracting.

5.20 At present this mechanism only applies tests for the coming quarter as it was primarily designed to address risks associated with droughts or transitory capacity shortages. As a result, it does not provide any information about exposure to longer-term risks, such as parties' exposure to movements in forward prices due to potential plant retirements. To address this the stress-test reporting horizon could be extended to 2-3 years (noting that different tests would need to be applied for forward periods than the coming quarter).

56 See https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

5.21 Another potential change would be to provide participants with information on how their stress-test results compare to all other parties. The comparator results would need to preserve confidentiality for other parties. The information should be useful for participants when assessing the reasonableness of their risk position.

5.22 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could improve incentives and would be relatively easy to modify or unwind. It also appears to have low risks of unintended adverse consequences and would align with the aim of 100% renewable supply.

5.23 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could improve incentives and would be relatively easy to modify or unwind. It also appears to have low risks of unintended adverse consequences and would align with the aim of 100% renewable supply.

5.24 The Authority does not propose to pursue this option at present, subject to feedback, but could consider it if there were an increase in the risk of disorderly thermal plant closure.

D – Clarify availability and use of 'discretionary demand' control

5.25 As discussed earlier, uncertainty about the availability and use of discretionary demand control (such as ripple control) could hinder parties' ability to make efficient contracting and risk management decisions. That in turn could make it harder to achieve an efficient and orderly thermal transition.

5.26 In its Winter 2023 work this is referred to as Option E. It has been implemented, in that an urgent Code amendment came into effect on 3 May 2023[57]. The system operator started requesting discretionary demand information in the form of difference bids from 1 June 2023. The Code amendment is in effect for nine months, and the Authority will consider whether a permanent Code amendment is appropriate for winter 2024 and beyond.

5.27 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could improve information and incentives and would be relatively easy to modify or unwind. It also appears to have low risks of unintended adverse consequences and would align with the aim of 100% renewable supply.

5.28 The Winter 2023 solution is only intended as a temporary solution, but will act as an enabler for future participation of discretionary demand in the wholesale market as distributors will gain experience in bidding, and prospective contracting counter-parties such as retailers will have better visibility of the quantum of resource that could be made available to insure against scarcity prices and further shedding of consumer demand.

5.29 The Authority intends to undertake further work during winter 2023 to promote the participation of demand response in the wholesale market using the dispatchable demand and dispatch notification products which will be available as part of implementing the final phase of the real-time pricing project due for April 2023.

5.30 As this option has been pursued as part of the Winter 2023 work, it will not be pursued for the thermal transition work.

[57] See https://www.ea.govt.nz/projects/our-projects/decision-to-implement-option-e-and-not-progress-option-g/

E – Require retailers to make compensation payments to customers affected by forced power cuts

5.31 As discussed in paragraph 4.41, a factor that could reduce the retailers' incentive to forward contract on behalf of their consumers is the treatment of forced power cuts in retail supply contracts.

5.32 The Authority's recent paper on Winter 2023[58] raised the possibility of requiring retailers to compensate consumers if their demand was forcibly curtailed due to inadequate supply. The Authority concluded that the design of any retailer compensation payments would need to be to be carefully designed to ensure that the desired outcomes were achieved.

5.33 It also noted that any customer compensation scheme must be cognisant of the technical limitations facing retailers and their ability to individually influence the impacts on their customers. The Authority will review the option of retail compensation payments for further development post-winter 2023.

5.34 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could improve incentives but may be difficult to modify or unwind once implemented. This is because consumers are likely to oppose any changes that reduce the value of compensation, even if that were judged likely to improve efficiency. This option is assessed as having moderate risks of unintended adverse consequences because of the complex issues that would need to be considered. If implemented, this option should align with the aim of 100% renewable supply.

5.35 The Authority does not intend to pursue the option of compensation payments, although it could be considered if the risks of disorderly thermal transition were to increase.

F – Introduce new ancillary service product(s)

5.36 The Authority's recent paper on Winter 2023[59] found that there may be a case for a new 'standby reserve' ancillary service – that is, flexible resource held in reserve, available to respond to unexpectedly large variations in net demand (demand minus intermittent generation such as wind or solar generation).

5.37 The Authority has stated it is prioritising this option for possible introduction post-winter 2023. The aim would be for any new service to be integrated with the energy spot market. An integrated ancillary service would allow resource to be offered into both the ancillary service market and the spot market, with resource divided between each market depending on the lowest overall costs (this is known as co-optimisation). This would prevent providers from inefficiently swapping between markets as the value of one product varies relative to another. Efficiency would also be fostered by technology-neutral procurement, and by allocating procurement costs of any new ancillary services to causers where practical.

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58 See https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf

59 See https://www.ea.govt.nz/documents/2102/Driving-efficient-solutions-to-promote-consumer-interests-through-winter-2023-_D28umrs.pdf. A similar proposal has also been raised by the Authority's Market Development Advisory Group – see https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf.

5.38 To promote competition and ensure that any new ancillary service does not act as an inefficient subsidy for unproductive plant, a new ancillary service for standby reserve should be technology agnostic and neutral between demand and supply side source of flexibility and integrated with the spot market.

5.39 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could improve incentives, but could be difficult to integrate with the spot market and would take some time to design / develop and implement. It is expected to align with the aim of 100% renewable supply because procurement would be technology neutral (i.e. not favour thermal plant).

5.40 As noted, the Authority has already committed to this option in the post-Winter 2023 work, so it is not necessary to consider it for the thermal transition work.

G – Introduce minimum notice period for reductions to plant capacity

5.41 In Australia, two thermal plant closures were notified with only 6-12 months' notice, and this led to the introduction of information disclosure requirements, whereby generators must notify the authorities of the expected dates of closure of their plant. A minimum notice period of three years is required, although generators can apply to the regulator for a shorter notification period.

5.42 The information disclosure requirements are intended to ensure that both the market operator and market participants have sufficient visibility of a closure, thereby helping to inform a market and operational response in sufficient time to help maintain reliability.

5.43 In terms of the evaluation criteria, the Authority's preliminary assessment is that the option of information disclosure and a minimum notification period before closure could prove useful and would be relatively easy to modify or unwind. It also appears to have moderate risks of unintended adverse consequences and would align with the aim of 100% renewable supply.

5.44 The Authority does not recommend this option at present but could consider it if the risks of a disorderly thermal transition were to increase.

H – Introduce a capacity mechanism

5.45 Capacity mechanisms (CMs) place an obligation on wholesale purchasers to hold forward cover for their assessed share of projected system demand.[60] Such cover can be via contracts or generation or demand response capacity. This approach is designed to address incentive gaps that could otherwise lead to insufficient forward contracting.

5.46 The requirement on all demand-side entities in the wholesale market to hold forward cover means that there should be adequate revenue streams to underwrite the expenditures needed to build or retain the resource needed to satisfy projected demand. In systems with a CM, the spot market continues to exist to provide operational incentives but is typically subject to a relatively low price-cap as suppliers derive much of their revenue from capacity payments.

5.47 CMs apply in much of the United States and in some other jurisdictions (e.g. Western Australia). Most overseas CMs are focused on ensuring adequate capacity is installed to serve peak demand because that has been the key reliability risk in those systems and

60 The Authority's Market Development Advisory Group has also raised this option in a recent report. Its preliminary view is that the option should not be pursued further as there are better alternatives available. See https://www.ea.govt.nz/assets/dms-assets/31/MDAG-options-paper-final-2.pdf

to complement caps on spot prices.[61] As far as we are aware, the only CM designed to address energy-adequacy issues in a system with a large hydro base is that operating in Colombia.

5.48 The main features of CMs include:

(a) Explicit reliability target – CMs specify an explicit target level of capacity (or energy) adequacy. This provides the anchor for determining the aggregate level of resources needed to meet projected demand in future years.

(b) Purchaser obligations – wholesale purchasers are required to hold sufficient capacity rights to match their assessed share of the overall system demand over (say) the next three years.

(c) Supplier monitoring – to provide assurance that capacity being pre-contracted is real, generators and demand response providers cannot sell more than their 'qualified' capacity. Assessment is normally overseen by a regulator, following rules covering issues such as fuel availability for thermal plants, derating factors for intermittent generation, definitions of plant retirement and commissioning etc.

(d) Registry – CMs need a registry to record the number of qualifying capacity rights available for sale by each supplier, the holdings of each wholesale purchaser (to match their assessed demand), and sales and purchases of rights between participants. The registry must also account for generation investments and retirements, and movements in consumers between parties due to retail competition.

(e) Contracting horizon – the obligation to purchase capacity rights typically covers future years to provide investment assurance (noting the lead-time to build new generation is typically more than one year). This can pose a challenge for purchasers whose future needs are not clear, such as a large industrial user with uncertain demand.

(f) Procurement and cost recovery mechanism – capacity can be procured centrally on behalf of all purchasers (usually via an auction), or by purchasers themselves via negotiation agreements, or via a hybrid mechanism.

5.49 CMs have been largely effective at achieving their intended objective – which is ensuring adequate installed capacity to meet demand. However, it is generally held that consumers pay more with CMs because there is a tendency for rules to be written (or interpreted) in a way that leads to over-procurement. This is because CMs put a central party in charge of decisions about the level of generation that must be installed. These decision makers face asymmetric incentives because the cost of any under-procurement is clear (power cuts) whereas the cost of over-procurement is harder to detect but no less relevant. In addition, CMs also tend to dull the incentives to innovate and seek out least-cost generation (or alternative) options because of the level of prescription required around matters such as plant derating factors.

5.50 In terms of achieving operational reliability (i.e. ensuring that plant is available to run when needed) CMs have had a more mixed record. For example, a number of North

[61] Some commentators argue that CMs address a 'missing money' problem that arises if spot prices are capped at a level that doesn't provide adequate revenues for suppliers. However, this issue can be addressed by allowing spot prices to correctly signal the value of supply – e.g. via uncapped scarcity prices. Interestingly, some CMs in North America have recently adopted mechanisms akin to scarcity prices to overcome the issues caused by low spot-price caps in the CM design.

American CMs had near-miss events in the mid-2010s when unexpectedly large volumes of plant were not available when needed. That prompted a closer focus on operational incentives – including introducing penalties for non-performance that mimic scarcity pricing in spot markets.

5.51 Another area of challenge with CMs relates to their complexity. The CM rules need to be prescriptive about many issues, especially the expected supply and demand characteristics of different generation and consumer types during periods of system stress, since these factors are critical to determining suppliers' contracting capacity and purchasers' obligations respectively. Developing rules to cover these issues is complex but was workable in systems that were largely thermal-based and where demand was relatively predictable.

5.52 However, the global trend to decarbonise electricity systems is making this more challenging. First, it is inherently more difficult to define the expected firm supply contribution of a renewable resource rather than a thermal plant because the former depends much more on weather, which is unpredictable. Furthermore, the firm supply contribution from a portfolio of renewable units will be greater than the sum of the firm supply of individual renewable units because of diversity effects. Some commentators have suggested that CMs may unduly discount the contribution of renewables, and inadvertently delay the transition away from thermal plant.

5.53 Another issue is that firmness needs to be assessed over some period. Most CMs focus on capacity adequacy over a few hours of peak demand, but that may not be the key reliability challenge in future. It could instead come at a time of low supply from variable renewable resources rather than very high demand. This makes it harder to assess the firm supply capability of the individual resource providers during reliability events. Likewise, demand is becoming harder to predict with a rising penetration of self-supply and distributed batteries and flexible load (e.g. from car charging).

5.54 It is not yet clear how CMs will evolve to the changes being brought about by technology and decarbonisation. However, these challenges are becoming more apparent. For example, one of the world's largest CMs is that operated by PJM. In February 2023, the Federal Energy Regulatory Commission (by majority decision) approved a contentious change to PJM's CM but stated:

> "Notwithstanding our determination that PJM's section 205 application is just and reasonable, we acknowledge that there have been continuing disputes and complaints about the operation of PJM's capacity market from a wide spectrum of stakeholders throughout the thirteen states and the District of Columbia served by PJM. To consider these issues generally, outside the parameters and constraints of a particular proceeding, the Commission will convene a forum to examine the PJM capacity market and how best to ensure that it achieves its objective of ensuring resource adequacy at just and reasonable rates. We will provide details about this forum in the near future."[62]

5.55 Finally, it is important to note that introducing a CM would require substantial changes to existing arrangements and likely take three or four years to introduce. In this context, it is interesting that Alberta and Singapore decided to adopt CMs in recent years, but later changed those decisions.

62 See https://elibrary.ferc.gov/eLibrary/filedownload?fileid=625633ba-b3d3-c56c-9565-86775c300000.

5.56 In Australia, the information disclosure requirements (see option G) have been useful but there remain significant concerns about resource adequacy, originally raised through the Energy Security Board's recent NEM 2025 work program, and which ultimately led the ESB to develop a capacity mechanism. Specifically, the ESB initiative and more recently, government support for a capacity mechanism, have been in response to insufficient investment occurring in dispatchable capacity.

5.57 In turn, the lack of investment has been driven by various factors including uncertainty over climate policy, demand uncertainty, uncertainty over the timing of large power station closures, increasing government intervention across the market, and intolerance of high wholesale and retail prices – all of which combine to create investment uncertainty. Those concerns have led to the consideration and implementation of additional interventions at the state level, to retain sufficient thermal generation capacity. The interventions include funding thermal generators to remain open, as has already happened for one generator in Victoria.

5.58 The ESB was initially charged with developing a CM but in late 2022 the Commonwealth Government took over responsibility for determining the design of the CM, and is likely to run a consultation process in May 2023 on the launch of a pilot CM. The mechanism will source non-fossil-based dispatchable capacity and will be supported by Commonwealth Government funding.

5.59 In general, it appears that a CM could provide more assured revenues for owners of back-up resources (including potentially thermal plant) and potentially reduce some transition risks. However, it is not clear whether consumers would benefit from a CM because of its tendency to raise overall system costs. In addition, adopting a CM would be a substantial change, take years to design and implement, and may create new forms of uncertainty and risks for consumers and suppliers.

5.60 It is also not clear that CMs are the best approach to facilitate the shift to a renewables-based system.

5.61 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could address some incentive gaps and therefore reduce thermal transition risk. However, it would require major changes to the existing arrangements and would be difficult to modify or unwind. It also appears to have relatively high risks of unintended adverse consequences because of the tendency to raise costs, the complex issues that would need to be addressed and a lengthy implementation period.

5.62 Finally, it should be possible in principle to design a CM that aligns with the aim of 100% renewable supply. However, some overseas commentators have suggested that in practice it is difficult to overcome the tendency for CMs to favour thermal resources, because their firmness is easier to assess than for renewables.

5.63 Having decided not to pursue a capacity mechanism in the Winter 2023 work, the Authority would not recommend a capacity mechanism to mitigate the risks of a disorderly thermal transition.

I – Introduce a contingent contracting obligation

5.64 CMs impose a standing obligation on all wholesale purchasers to hold forward cover for their assessed share of projected demand for a defined future time horizon (say three years). A more limited option would be for such obligations to be imposed only on a contingent basis, such as if there is a projected gap between supply and demand in the future.

5.65 A mechanism of this type has been applied in the Australian NEM and is called the Retailer Reliability Obligation (RRO).[63] Under the RRO, where the market operator identifies a reliability gap, obligations are placed on retailers to source sufficient contracts to underpin investment. In addition, the larger, vertically integrated suppliers (gentailers) can be subjected to a Market Liquidity Obligation (MLO) under which they must be prepared to offer some power contracts to smaller retailers.

5.66 The RRO allows the regulator to trigger an obligation on retailers and other wholesale purchasers to hold qualifying contracts (or generation rights) for their share of projected peak demand, if the regulator (on advice from the market operator) identifies a reliability gap in the three-year outlook.

5.67 The expectation is that purchasers will then seek additional contracts which in turn will spur new investment in supply or an increase in contracted demand response. This should close the projected reliability gap.

5.68 However, if a reliability gap still remains in the projections with 12 months to run, the regulator (again on advice from the market operator) can trigger a tender to acquire resource to fill the gap (such as contracted demand response). The cost of acquiring such resources is to be recovered from any retailers/purchasers with insufficient contracts/generation to cover their assessed peak demand, with costs per party capped at A$100 million.

5.69 The RRO has many features which are CM-like. In particular, a requirement for purchasers to hold contracts or generation rights on a forward basis is a hallmark of CMs. However, the requirement does not actually apply unless the regulator (acting on advice) makes a specific RRO determination. If such a determination were to be made, it would apply only to specified regions and time periods.

5.70 Thus, the default position for parties is that they determine their own contract positions, albeit in the knowledge that an RRO might be triggered at some point.

5.71 In principle, an RRO-like mechanism may be more flexible and lower cost than a CM because it applies only if needed. On the other hand, it would likely require much of the same machinery to be in place as a CM (registry, measurement criteria for contract firmness, etc). It would also face similar challenges in measuring the firmness of demand and supply contributions from different resource types.

5.72 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option could address incentive gaps and therefore reduce thermal transition risk. However, it would require some significant changes to the existing arrangements and could be difficult to modify or unwind (although less so than a full CM). It appears to have some risks of unintended adverse consequences because of the complex issues that would need to be addressed, but again less so than a full CM.

5.73 Finally, as with a full CM, it should be possible in principle to design a contingent contracting obligation that aligns with the aim of 100% renewable supply. However, some overseas commentators have suggested that in practice it is difficult to overcome

63 See www.aer.gov.au/retail-markets/guidelines-reviews/retailer-reliability-obligation-reliability-compliance-procedures-and-guidelines#:~:text=The%20Retailer%20Reliability%20Obligation%20(RRO,entities%20involved%20in%20the%20RRO.

the tendency for mandatory contracting arrangements to favour thermal resources, because their firmness is easier to assess than for renewables.

5.74 The Authority does not recommend a contingent contracting obligation at present, but could consider this option if the risks of a disorderly thermal transition were to increase.

J – Introduce a strategic reserve scheme

5.75 Strategic reserve schemes (SRs) are a form of compulsory contracting mechanism in which a subset of resources qualify to receive regulated revenues. [64]

5.76 SRs operate by:

(a) Contracting for the retention or construction of resources that would not (or may not) be provided by market incentives alone. These additional resources are intended to lift reliability above a market-determined level.

(b) Seeking to preserve the 'normal' incentives for the provision of all other resources as far as possible. To this end, resources in a strategic reserve need to be tightly quarantined from the rest of the system – otherwise their presence will affect the incentive to provide other resources and overall reliability may be unchanged.

5.77 Quarantine arrangements typically include:

(a) Rules that provide for strategic reserve resources to be used only as a last resort to 'keep the lights on', and once all 'normal' market resources have been exhausted.

(b) High minimum-offer prices for strategic reserve resources (above those of 'market' resources), or for clearing prices in the spot market to be set to scarcity values when SR resources are used.

(c) A levy mechanism to recover any costs for SR provision that are not recouped via spot revenues.

5.78 The key challenge with strategic reserves is that they can undermine incentives for 'normal' contracting and investment. This is likely if market participants view the quarantine arrangements as being unsustainable. One challenge is maintaining the quarantine if an SR is not used for a long time (which is likely for last resort resource). In this situation wholesale purchasers may seek to reduce the offer price of SRs to allow for more running time to reduce the share of standing costs that are being recovered from levies. Another challenge is that during tight supply periods pressures to lower the offer price for SR resources can emerge, since that may help to lower spot prices.

5.79 Sweden, Germany and Belgium (among other countries) currently have strategic reserve schemes. New Zealand introduced a strategic reserve scheme in 2003. The Whirinaki diesel-fired station was the only resource actually procured, and there were plans (not completed) to acquire additional demand response in 2008. Despite a clear intent at the outset, it proved difficult to maintain a tight quarantine for the scheme during an extended drought in 2008. Subsequent to that event the scheme was reviewed and terminated.

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64 The Authority's Market Development Advisory Group has also raised this option in a recent report. Its preliminary view is that the option should not be pursued further as there are better alternatives available. See https://www.ea.govt.nz/documents/1247/MDAG-Library-of-options-FINAL-1.pdf..

5.80 In some countries SRs have been introduced as a temporary measure with a sunset date. This was intended to reinforce the quarantine and reduce the likelihood that the presence of SR resources would hinder investment in new alternatives. This was the case in Sweden and Germany where older thermal plant was paid to remain on the system but kept in a quarantined role. However, experience suggests that it can be difficult to close SR schemes once they are in place. For example, the Swedish scheme was due to terminate in 2008 but has since been extended three times.

5.81 SRs are simpler to adopt than a full CM and therefore should be faster to implement. However, a robust SR scheme would still require many elements of a full CM. These include:

(a) Explicit reliability target

(b) Rules to measure the firmness of projected demand and supply – to determine whether additional/less SR resource should be procured.

(c) Monitoring arrangements to provide assurance that SR resources are real.

(d) Procurement mechanism – this must be centralised with a SR because resources would be procured on behalf of wholesale purchasers as a collective. Cost recovery is typically via a levy mechanism. In principle it would be preferable to recover costs from beneficiaries (e.g. wholesale purchasers that have not pre-contracted) but that is difficult in practice.

5.82 In terms of the evaluation criteria, the Authority's preliminary assessment is that it is not clear that this option would improve incentives. It depends on whether a quarantine is viewed as effective and sustainable. Historical experience in New Zealand suggests this may be difficult to achieve. An SR would be easier to modify than a CM, but experience elsewhere suggests they can be hard to remove once established. Finally, by their nature SRs tend to be designed to retain ageing thermal plant. For this reason they may not be aligned with the aim of 100% renewable supply.

5.83 Having decided not to pursue a strategic reserve in its Winter 2023 work, the Authority would not consider this option to mitigate the risks of a disorderly thermal transition.

K – Pre-arranged short-term emergency reserve scheme

5.84 Another option that seeks to provide additional assurance about reliability is to allow the system operator to pre-arrange short-term emergency reserve resources, which can be activated if certain preconditions apply. As discussed below, while this type of mechanism has an operational focus, it may affect thermal plant retention/retirement decisions.

5.85 A mechanism of this type exists in the Australian NEM and is called the Reserve Energy and Reliability Trader (RERT).[65] In summary:

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[65] The RERT has some similarities to the ancillary service product proposed by the CEO Forum in late 2022 in response to the Authority's consultation paper on winter 2023 reliability. However, the RERT design is more comprehensive in its scope. For example, the RERT includes specific provisions to address the risk that use of the reserve could undermine normal market incentives to supply resources. The CEO Forum proposal acknowledged the potential risk but the design did not specify how it would be addressed. See page 21 of https://www.ea.govt.nz/documents/1655/CEO-Forum-Submission-161222-1383294.pdf.

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(a) Qualifying parties can register to join a panel of RERT providers. Registration confers no payment or delivery obligations but shortens the lead time if RERT is procured.

(b) Panel membership is open to demand response providers or generators (such as basement diesel generators) that do not participate directly in the wholesale market. This provision is intended to ensure that resources procured in the RERT are additional to those operating in the wholesale market.

(c) The system operator can offer to procure reserve from panel members if forecast reliability falls below a pre-defined standard. Such procurement can be for one of three products: long notice (between 12 months and 10 weeks ahead), medium notice (between 10 weeks and seven days ahead) and short notice (less than seven days ahead). The system operator can make payments for availability but is not obliged to do so.

(d) The system operator can dispatch/activate RERT to maintain power system security if it considers that activation will not distort the market and the cost is less than the value of reliability to consumers.

(e) Spot prices are calculated as if RERT did not apply – this is intended to avoid any chilling of investment or risk management incentives that could otherwise occur from the procurement of RERT.

(f) Activation costs are recovered pro-rata from purchasers in the relevant trading period and other costs as a share of consumption over the billing period in which payments were made.

5.86 Proponents of the RERT argue that it creates a buffer zone between purely market-based arrangements (when the normal market clears) and the administrative realm (when forced load-shedding is required). This can help to ensure orderly management of tight supply events and reduce the likelihood of actions that could inadvertently undermine market incentives. More specifically, the RERT may help to validate the basis for high spot prices during shortage events because RERT procurement costs are inherently high[66] and provide an external marker not linked to generators' spot market offer prices. For example, in 2021/22 the RERT was used to procure 10 short-notice contracts and five were activated at a cost of A$130m (equivalent to A$23,842/MWh).

5.87 On the other hand, critics argue that a RERT-like mechanism is unnecessary and may simply cause some resource providers to contract with the system operator, rather than offering directly into the spot market or participating via a demand response aggregator. In other words, a RERT-like mechanism may fail the 'additionality test'. Furthermore, to the extent that the reward for participation in the mechanism exceeds the return in the spot market, this could create gaming incentives, i.e. parties withhold resources from the spot market to obtain higher payment from the RERT-like scheme. The Australian scheme seeks to address these issues via requirements that reserve providers cannot have participated in the spot market in the last 12 months, and for the system operator to only procure if costs are lower than the pre-defined value of reliability to consumers. However, it is difficult to judge the effectiveness of these mechanisms.

[66] Generation and demand response that has a low cost is likely to already have been utilised before a shortage event occurs.

5.88 In terms of the evaluation criteria, the Authority's preliminary assessment is that this option is unlikely to improve information. As regards the effect on incentives, it depends on whether market participants would view this mechanism as reinforcing or undermining the case for accurate (i.e. high) spot prices during very tight supply events. This is a matter on which it would be useful to hear stakeholder views. More generally, if a short-term emergency reserve scheme were introduced, it should be easier to modify or remove than a CM or SR. Finally, there is no information to suggest that this option would be misaligned with the aim of 100% renewable supply. This is based on the fact that the RERT in the NEM treats resource providers on a technology neutral basis.

5.89 Having decided not to pursue a similar scheme in the Winter 2023 work, the Authority would not consider a pre-arranged short-term emergency reserve scheme to mitigate the risks of a disorderly thermal transition.

15. Do you have any views on the options discussed above, and how useful they might be if thermal transition risks increase in future?

Any other options

5.90 The preceding sections describe high level policy options that have been identified as possible ways to mitigate thermal transition risk, should the need arise. The Authority is aware that other types of option have been raised to address transition risk. For example, Contact Energy has proposed the establishment of 'Thermalco' as a vehicle to facilitate an "industry-wide, market-based solution to manage the retirement of thermal electricity generation".[67]

5.91 As far as the Authority is aware, the Thermalco proposal would not require changes to the existing Code. It has therefore not been evaluated as a possible policy option to facilitate the transition to renewables.

5.92 More generally, the Authority welcomes stakeholder views on any other options that should be considered to reduce thermal transition risk.

5.93 The Authority welcomes stakeholder views on any policy options (other than those in Table 3) that should be considered to reduce thermal transition risk.

16. What other options (if any) could be explored to mitigate thermal transition risks, should these risks increase in future? Please explain your reasoning.

67 See https://contact.co.nz/aboutus/media-centre/2021/11/15/thermal-co-enabling-aotearoas-transition-to-renewable

Appendix A: Format for submissions

Question 1
Do you agree with the desired outcome as described? If not, what do you think is the desired outcome in respect of thermal generation during the transition? **Response**
Question 2
Are there any other aspects of thermal transition risks that should be considered by the Authority? **Response**
Question 3
Do you agree with the above expectation of the likely role of thermal generation throughout the transition? If not, what is your view and reasoning? **Response**
Question 4
What (if any) improvements could be made to information to aid decision-makers in relation to thermal transition risk? **Response**
Question 5
Are there any aspects in current spot market arrangements that are likely to undermine incentives to make efficient decisions in relation to back-up resources? If so, what are they? **Response**
Question 6
Do current arrangements provide balanced incentives to conclude forward contracts to manage thermal risks of transition appropriately? If not, what are the reasons for your view? **Response**
Question 7
Do current arrangements ensure reasonable availability of forward contracts related to back-up services – such as dry year cover? Please explain your reasoning. **Response**

Question 8
To what extent do current arrangements create potential for misaligned incentives between retailers and consumers in relation forward contracting with adverse impacts on thermal transition risk? Please explain your reasoning. **Response**
Question 9
To what extent do current arrangements relating to use of ripple control in periods of tight supply affect thermal transition risk? Please explain your reasoning. **Response**
Question 10
Do you agree with the Authority's view above that lumpiness does not (at present) threaten to disrupt an orderly thermal transition? If so, or if not, please explain your reasoning. **Response**
Question 11
To what extent are there any selective support mechanisms paid outside the wholesale market which could pose a challenge to achieving an efficient thermal transition? Please explain your reasoning. **Response**
Question 12
To what extent is thermal generation providing a service that is needed but not explicitly priced and rewarded? Please explain your reasoning. **Response**
Question 13
To what extent will thermal retirement/investment decisions be driven by non-financial factors? Please explain your reasoning. **Response**
Question 14
What (if any) other factors could undermine an efficient thermal transition? Please explain your reasoning. **Response**

Question 15
What (if any) other evaluation criteria should be considered? Please explain your reasoning. **Response**

Question 16
What other options (if any) could be explored to mitigate thermal transition risks, should these risks increase in future? Please explain your reasoning. **Response**

Appendix B Concept Consulting analysis of demand for thermal generation in transition

View the Concept Consulting analysis of demand for thermal generation in transition.