Advancing New Zealand's energy transition

Submission by the Major Electricity Users' Group (MEUG)

www.meug.co.nz

2 November 2023

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Ministry of Business, Innovation and Employment
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Sent via email: energystrategy@mbie.govt.nz

Dear Justine

Advancing New Zealand's energy transition

1. This is a submission from the Major Electricity Users' Group (MEUG) on the Ministry of Business, Innovation and Employment's (MBIE) consultation package *Advancing New Zealand's energy transition* published for consultation in August 2023. Our submission comments on the following discussion papers:

   a) Measures for Transition to an Expanded and Highly Renewable Electricity System[1]

   b) Measures for implementing a ban on new fossil-fuel baseload electricity generation[2]

   c) Gas Transition Plan[3] [4]

   d) Developing a Regulatory Framework for Offshore Renewable Energy[5]

2. MEUG was established in the early 1990s to advocate for, and support, a well-functioning electricity market. Our 14 members represent industries of national and strategic importance to New Zealand such as steel, aluminium, pulp and paper, and the dairy industry. Our newest members include businesses across the supply chain, operating food packing and cool store facilities, the distribution and retailing of groceries, and as of next year, the provision of data and cloud services.

3. MEUG members have been consulted in the preparation of this submission. Members may lodge separate submissions. This submission does not contain any confidential information and can be published on MBIE's website unaltered.

[1] https://www.mbie.govt.nz/dmsdocument/26909-measures-for-transition-to-an-expanded-and-highly-renewable-electricity-system-pdf
[2] https://www.mbie.govt.nz/dmsdocument/26908-implementing-a-ban-on-new-fossil-fuel-baseload-electricity-generation-pdf
[3] https://www.mbie.govt.nz/dmsdocument/27255-gas-transition-plan-issues-paper-pdf
[4] While MEUG is not submitting directly on the *Interim Hydrogen Roadmap* but has highlighted our comments that are also applicable to this consultation paper.
[5] https://www.mbie.govt.nz/dmsdocument/26913-developing-a-regulatory-framework-for-offshore-renewable-energy-pdf

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Development of an Energy Strategy

4. MEUG welcomes consultation on this important suite of discussion papers that will inform the development of New Zealand's Energy Strategy (the Strategy) and support our country's transition to a net-zero economy by 2050.

5. The development of the Energy Strategy was one of the key actions set out in Aotearoa New Zealand's first emissions reduction plan (ERP) [6] and will guide upcoming actions across the energy sector, working towards future emissions budgets. This Strategy provides an important contribution to our energy policy and regulatory landscape, by:

   - Taking a whole of system / holistic approach, discussing the interlinkages of policy choices and sector actions on energy-related emissions.
   - Looking at the blend of appropriate market incentives, regulations, sector-led work, and government interventions / funding.
   - Considering the trade-offs and benefits of different policy options or scenarios, striving towards optimal overall outcomes and the greatest reduction in emissions.

6. MEUG and our members stress the importance of ensuring residential, business, and industrial consumers' needs are central to decisions made on the Strategy. Electricity is a key input for our members' businesses. It enables our members to support regional communities, employ thousands of people in well-paying jobs, and helps to pay for the essential services we all take for granted that are critical to a dynamic and thriving economy. **An affordable and reliable electricity market where customers believe they are paying a fair or justifiable price is essential to a productive economy**. For this reason, it is reassuring that the terms of reference for this Strategy include both affordability and productivity as key objectives.[7]

7. MEUG considers that Government's focus should be on providing an enabling environment and clear regulatory settings through the Strategy, and support for continue d collaboration across the energy sector. As we discuss in our submission, it is preferable to let the market drive the optimal outcomes and for the Government to avoid picking winners or setting rigid targets that don't adapt over time as the environment and technology evolves. This aligns with many of the key themes highlighted in KPMG's recent report *30 Voices on 2030: The Future of Energy in Aotearoa*[8], where energy sector leaders called for collaboration and regulatory certainty, and stated that we do not need an aspirational target of 100% renewable electricity generation.

8. We observe that the signals Government sends to the market can have a direct impact on investment sentiment in the energy sector. It is quite clear from numerous industry participants and commentators that both the NZ Battery Project and the oil and gas ban had a chilling impact on investment sentiment, and, as importantly, sent a negative "sovereign risk" message to the offshore parent companies that have New Zealand assets (including the majority of MEUG members). At a time when foreign direct investment and expertise will be needed for New Zealand to successfully navigate the energy transition, we would urge government and policy makers to take this fact more fully into account as the Energy Strategy is developed.

[6] https://environment.govt.nz/assets/publications/Aotearoa-New-Zealands-first-emissions-reduction-plan.pdf
[7] https://www.mbie.govt.nz/dmsdocument/25373-terms-of-reference-new-zealand-energy-strategy
[8] https://assets.kpmg.com/content/dam/kpmg/nz/pdf/2023/10/30-voices-on-2030-v2.pdf

Key recommendations for development of the Energy Strategy

9. When developing the Strategy and near-term policy for the energy sector, MEUG recommends that the Government focus on the following areas. These recommendations align with MEUG's focus on ensuring an affordable and reliable electricity market for consumers going forward.

<u>Measures for transition to an expanded and highly renewable electricity system</u>

a) Investigate the disparity between wholesale electricity prices and cost drivers, to affirm whether the market is working as it should and to retain consumer confidence. This is a key priority and should be actioned without delay.

b) The percentage of renewable electricity generation should be market driven. The market is best placed to determine the optimal composition of generation, which may evolve over time. Government should not pre-set a specified percentage of renewable electricity generation required by a set timeframe.

c) The Strategy must address what the ongoing role for gas will be into the foreseeable future, particularly with respect to the need for thermal gas peakers to aid the transition of the electricity system to greater levels of renewable electricity generation.

d) Take urgent action to reform the Resource Management Act (RMA) to address the issues hampering the timely consenting of renewable electricity generation and infrastructure.

e) Explore opportunities to mature the Power Purchase Agreement (PPA) market to support greater renewables and put downward pressure on prices.

f) Rescope the "NZ Battery Project" to have a clear focus on addressing dry year risk and incorporate this within the Strategy. Lake Onslow should be removed from consideration and a focus on exploring multiple, market-led options for energy storage.

g) Make improvements to the current market mechanisms to ensure that demand-side response arrangements are mutually beneficial and incentivise participation.

h) Ensure that there is transparency around infrastructure pricing so that consumers can have confidence that costs are allocated fairly, and electricity transmission and distribution prices reflect the cost of supply.

i) Optimise the current arrangements within government agencies and regulators, rather than pursue structural reforms or additional measures, to enable the delivery of an effective Strategy and supporting work programmes.

<u>Ban on new fossil-fuel baseload electricity generation</u>

j) Stop work on the ban of new fossil-fuel baseload electricity generation ban. We consider that the market, and the price signals through the ETS, will determine the optimal electricity generation mix, and the role that thermal generation plays in the foreseeable future.

k) Ensure continued support for co-generation where it is an efficient choice for businesses and maximises energy streams by using waste streams to get heat or electricity.

Gas Transition Plan

l) There will be an ongoing role for gas into the foreseeable future. In particular, there is a pressing need for thermal gas peakers to aid the transition of the electricity system to a greater level of renewables, while maintaining a reliable electricity supply.

m) Support investigation into the viability of renewable gases such as hydrogen and biogas for the New Zealand market, and the potential for Carbon Capture, Utilisation and Storage (CCUS). Decisions around these technologies and fuels should be driven by the market (i.e., economics of projects, technical feasibility) and guided by the price signals from the ETS.

Regulatory framework for offshore renewable energy

n) We support Government developing a regulatory framework to enable the introduction of offshore renewable energy into the wholesale electricity market. The introduction of offshore wind, alongside other renewable electricity generation, will be beneficial, putting downward pressure on wholesale pricing.

o) MEUG does not support introducing support mechanisms specifically for offshore renewable electricity. We consider that if Government wants to continue to encourage development of renewable electricity generation, then it should not provide incentives or measures for only selected generation types (i.e., avoid picking winners) and rather provide a level playing field.

Finalising the Energy Strategy

10. We recommend that work on finalising the Strategy is not delayed, and the Government continue to pursue the completion of a strategy by the end of 2024. A Strategy is essential to guide actions going into the second and third emissions reductions plans. It is also essential to address the issues and opportunities discussed in this submission, so that New Zealand can optimise its energy transition, ensuring a productive economy.

11. MEUG has provided a list of submissions and publications in **Appendix A** that support the points raised in this submission.

12. We have also provided a report from the New Zealand Institute of Economic Research (NZIER) in **Appendix B**, which supports the comments made on the *Measures for Transition to an Expanded and Highly Renewable Electricity System* discussion paper.[1] The NZIER report answers a number of the consultation questions specifically raised in this issues paper.

Next steps

13. We would welcome the opportunity to discuss our submission with MBIE officials and Government representatives as work on the Strategy progresses to the next stage. If you have any questions regarding our submission or to set up a meeting, please contact MEUG on 027 472 7798 or via email at karen@meug.co.nz.

Yours sincerely

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Major Electricity Users' Group

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1. Measures for Transition to an Expanded and Highly Renewable Electricity System

Key recommendations from MEUG

- The Government investigate the disparity between wholesale electricity prices and cost drivers, to affirm whether the market is working as it should. This is a key priority and should be actioned without delay.
- New Zealand steps back from pursuing a 100% renewable electricity target by 2030. It is more beneficial for the sector to focus on increasing the level of renewable electricity to the highest extent commercially, technologically, and operational viable, while focusing on electrifying other sectors and reducing overall emissions.
- The Government provide regulatory certainty about the ongoing role for gas in the foreseeable future, including thermal gas peaking, to aid the transition to greater renewables generation.
- Urgent action is taken to reform the Resource Management Act (RMA) to address the issues with consenting renewable electricity generation and infrastructure and streamline the process.
- The Energy Strategy include an action around maturing the Power Purchase Agreement (PPA) market to support greater renewables and put downward pressure on wholesale electricity prices.
- That "NZ Battery Project" be rescoped and incorporated into the Strategy, with a clear focus on addressing dry year risk. Lake Onslow should be removed from consideration and a focus on exploring multiple, market-led options for energy storage (i.e., batteries, further gas storage fields, greater use of hydro lakes as reserves rather than constant baseload supply).
- Look for improvements to the current market mechanisms to ensure that demand-side response arrangements are mutually beneficial and incentivise participation.
- Ensure that there is transparency around infrastructure pricing so that consumers can have confidence that costs are allocated fairly, and transmission and distribution prices reflect the cost of supply.
- Focus on optimising the current arrangements within government agencies and regulators to ensure New Zealand can deliver an effective Strategy and supporting work programmes.

Introduction

14. The topics covered in this discussion paper are of most interest to MEUG and our members, and are where we believe that considerable improvements can, and must, be made to support the greater electrification of New Zealand's economy and the shift towards a low-emissions, productive economy.

15. As outlined above, electricity is a key input for our members' businesses. It enables our members to support regional communities, employ thousands of people in well-paying

jobs, and helps to pay for the essential services we all take for granted that are critical to a dynamic and thriving economy. An affordable and reliable electricity market where customers pay a fair price is essential to a productive economy. It allows industry and businesses to produce products at a competitive price, allowing our exporters to compete internationally, grow export revenue, drive job creation, and reinvest in their businesses.

16. However, **MEUG does not believe that consumers are currently paying a fair price – by this, we mean that the wholesale price does not reflect the underlying costs of generation, nor does the futures market reflect the long-run marginal cost (LRMC) of electricity generation**. This has led to a lack of confidence in the electricity market, and at a time when considerable investment is needed to both increase the level of electricity generated from renewable sources and expand our transmission and distribution network to meet increasing demand.

17. The long-term future of the market is undermined when consumers believe they are being taken advantage of. Government needs to demonstrate this is not the case or, if it is, show a willingness to address the market failings.

18. We set out our comments below on the chapters of most importance to MEUG and where we believe action is required.

Chapter 6: Workably competitive electricity markets

19. MEUG does not believe that wholesale consumers are currently paying a fair price for electricity, and this is hampering the energy transition. We consider that there is ample evidence demonstrating that there is a disparity between the wholesale electricity price that consumers are paying, and the cost of supply, both now and in the foreseeable future. This warrants further action-orientated assessment.

Issues with wholesale prices since 2018

20. Analysis by MBIE, the Electricity Authority, the Market Development Advisory Group (MDAG) and numerous sector commentators has all highlighted the issues with wholesale electricity prices.[9] Ever since the Pohokura outage in 2018,[10] there has been an increase in wholesale electricity prices and prices have remained at high levels, never returning to levels close to that in 2018. This is illustrated clearly by Figure 5 in MBIE's issues paper (replicated on the page below), with a clear uplift in pricing.

21. In addition to the spot market, there have also been observed issues with the futures (ASX) market, with forward prices still well above the LRMC and prices not adjusting to changes in current year events, implying that generators are pricing excessive risk into the forward market. Figure 2 below shows the futures prices as of September 2023, showing that all prices sit well above the expected LRMC estimated by Concept Consulting for MBIE.

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[9] For example, John Kidd, Enerlytica, https://www.interest.co.nz/opinion/109993/deep-dive-whats-causing-wholesale-electricity-prices-soar-and-manufacturers-curtail, Bryan Leyland, https://www.nzherald.co.nz/nz/bryan-leyland-why-our-unreliable-electricity-supply-is-so-expensive-and-what-to-do-about-it/RTONYOEE35Y64SBJPP5ROB5HJM/, and Tom Powell, https://www.stuff.co.nz/marlborough-express/300759450/new-zealands-broken-electricity-market

[10] https://www.nzherald.co.nz/business/extended-pohokura-gas-outage-costing-methanex-2-million-a-day/D2LKQIIZBI2OPU2OXHA3CYLRVY/ and https://www.rnz.co.nz/news/business/431939/problems-at-offshore-fields-lead-to-reduced-natural-gas-production

Figure 1: Contract prices and estimated costs for new baseload supply[11]

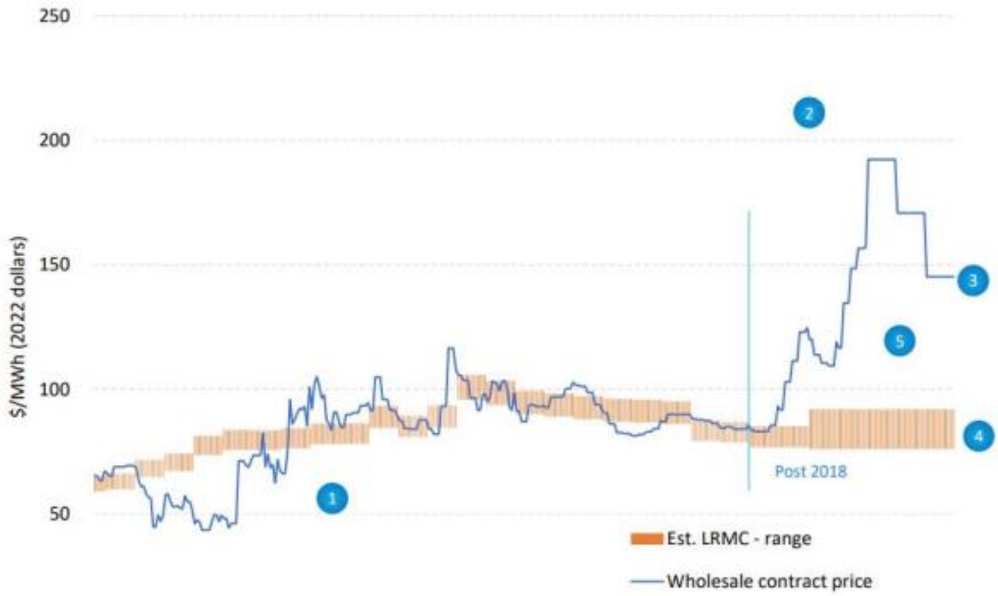

Figure 2: Forward pricing for electricity[12]

22. This disconnect is being discussed by sector commentators, with, for example, Forsyth Barr noting that:

> *"The opening futures contracts for the 2027 calendar at $143 a MWh did not reflect the new generation coming on stream or likely future demand. The analysts said a more realistic price was about $100MWh and expected actual earnings to reflect that."*[13]

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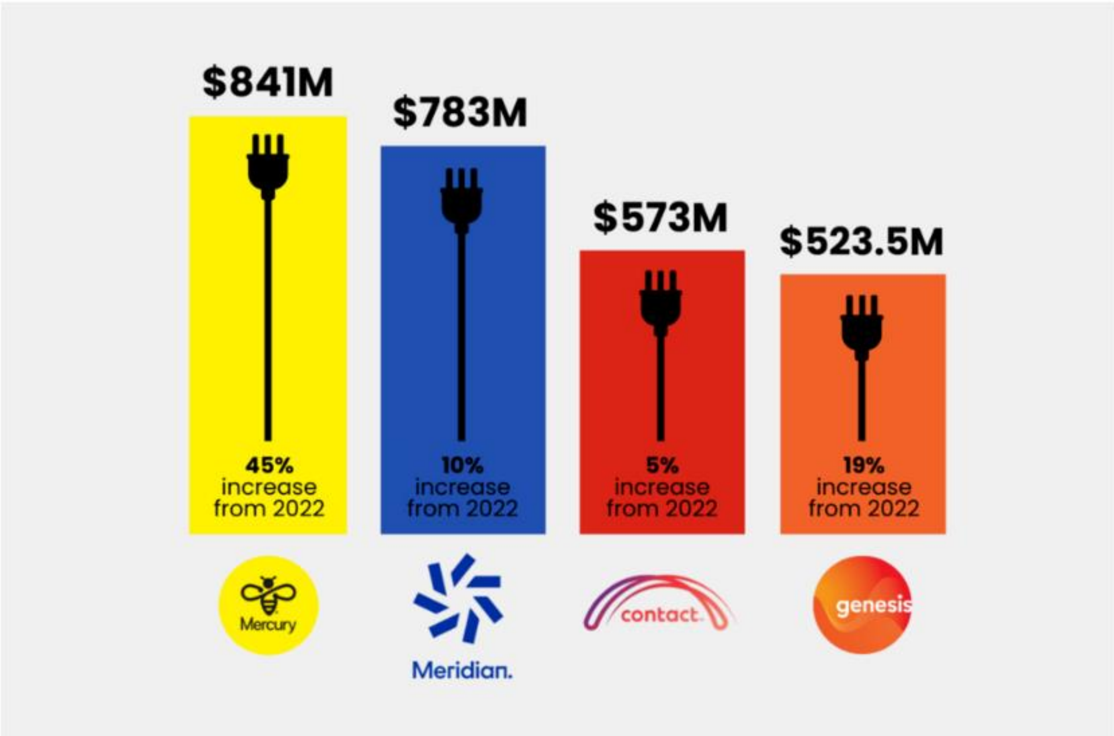
[11] Figure 5, page 58, *Measures for Transition to an Expanded and Highly Renewable Electricity System* issues paper.
[12] Market update September 2023 - https://www.smartpower.co.nz/blog/, with data sourced from https://www.emi.ea.govt.nz/
[13] *Analysts warn unrealistic electricity future prices could hit earnings*, Ian Llewellyn, Business Desk, https://businessdesk.co.nz/article/markets/analysts-warn-unrealistic-electricity-future-prices-could-hit-earnings.

23. This pricing issue is flowing through to the retail market, with concerns raised by several independent retailers and is informed by the Electricity Authority's Internal Transfer Price (ITP) disclosures[14] and the company results from the four large gentailers (see Figure 3 below).[15] For example:

- Octopus Energy has stated that "*an uncompetitive wholesale market dominated by large gentailers and lacking regulatory mechanisms to rein in their market power is holding the country back. She [Marcia Poletti] says the position these vertically integrated firms have has resulted in wholesale prices 20 per cent higher than they should be*."[16]
- The Electricity Authority analysis suggest that "*the disclosed ITPs for each year between 2018 and 2022 were broadly consistent with the benchmarks selected, although we note that the range of benchmark ITPs appears large relative to the retail gross margins needed for a retailer to be competitive. This makes any definitive conclusion about retail competition difficult*."[17]

Figure 3: Summary of gentailers reported earnings (EBIDAF)[18]



[14] https://www.emi.ea.govt.nz/Retail/Datasets/InternalTransferPricing/2022
[15] Contact Energy - https://businessdesk.co.nz/article/markets/contact-energy-kicks-off-earnings-season, Mercury Energy - https://businessdesk.co.nz/article/rain-and-wind-boost-mercury-energys-annual-earnings, Genesis Energy - https://businessdesk.co.nz/article/genesis-revenue-and-emissions-both-fall-amid-record-renewable-generation, Meridian Energy – https://businessdesk.co.nz/article/meridian-operating-earnings-up-10
[16] *Market power a handbrake on innovation* – Octopus, Energy News, 21 September 2023, https://www.energynews.co.nz/news/electricity/145861/market-power-handbrake-innovation-octopus
[17] Paragraph 171, pages 60-61, MBIE Issues paper, https://www.mbie.govt.nz/dmsdocument/26909-measures-for-transition-to-an-expanded-and-highly-renewable-electricity-system-pdf
[18] Copied directly from ConsumerNZ, https://www.consumer.org.nz/articles/profits-surge-for-new-zealand-s-gentailers

- The Electricity Authority's survey[19] of market participants paints a less than positive view about the state of competition in the electricity market and how this could harm the energy transition.
- ConsumerNZ has stated that "*the "big four" power companies are earning more than $7 million every day while some households struggle to heat their homes*" …. "*We acknowledge that profits are a healthy and normal part of business, but there's a question around what is excessive*."[20]
- OurPower sold its retail business to Genesis Energy, stating that ""*we can no longer buy electricity at a competitive price from the ASX, it's therefore not sustainable to continue operating*."[21]

24. From MEUG's review of the information, the publishing of internal transfer prices has shown that while the internal transfer price is comparable to the spot market price, more importantly, the quarterly annual results have shown that the big four gentailers can run their retail business unit at a loss and still make a company-wide profit by relying on the generation business unit.

25. This is concerning and suggests that further analysis is needed to get a better understanding of the state of the market, including looking at retail profitability. If this is not done, there is a risk independent retailers will be forced from the market.

<u>What this means for businesses and industry</u>

26. These increasingly high wholesale electricity prices are negatively impacting businesses and industry, by:

    a) Making it difficult for businesses to source electricity supply at a reasonable price and necessitating businesses to explore a broader range of options to secure supply.

    b) As electricity input costs rise, this impacts the profitability of businesses, including their ability to expand or in some cases, continue running in New Zealand. This can lead to an uplift in cost for the goods and services produced, which is passed onto consumers.

    c) Increasing prices have an impact on business decisions around electrifying process heat. In short, it is unrealistic to expect industrial companies to significantly increase their load while the electricity price remains so elevated – high electricity prices undermine decarbonisation investment strategies for electrification of process heat.

    d) Reducing confidence in the New Zealand wholesale electricity market and the ASX futures market. For international firms, this can impact the level of business undertaken in New Zealand versus the

Energy affordability and productivity

The Pan Pac Pulp mill is an example of energy enabling productivity. They employ 20 people to directly make over 600 tonnes per day of mechanical pulp through the investment in machinery and that machinery having access to affordable energy. Those individuals without machinery and energy could only make a few kilos per day, if making by hand.

Energy is leveraging that individuals' efforts by over a thousand times, with staff rewarded with good wages.

A BERL report from 2021 identified that Pan Pac's GDP/FTE is around $265,000/year – as compared to Agriculture around $117,000/year and the Hawkes' Bay average $109,000/year.

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[19] Survey of electricity industry participant perceptions 2021/22 (ea.govt.nz)
[20] 'Big four' power companies earning $7 million every day | Stuff.co.nz
[21] OurPower can't compete, sold for Genesis, Energy News, 17 May 2023, https://www.energynews.co.nz/news/electricity-retailers/139192/ourpower-cant-compete-sold-genesis

choices to base operations in other jurisdictions with more favourable economic conditions.

27. These outcomes are counter to the objectives for the Energy Strategy, where there is a focus on productivity and affordability.

Overwhelming evidence of issues in wholesale electricity market

28. MEUG believes that there is already ample evidence[22] that undermines confidence in the wholesale market and points to enduring issues with competition and market rents:

- The Commerce Commission's 2009 wholesale market review (Wolak) found market power was exercised and around $4.3 billion in excess rents over 2001 to 2007.
- Modelling by Browne et. al. (2011) using an alternative simulation model to Wolak, estimated total market rents for 2006 to 2008 to be $2.6 billion.
- Poletti (2016) identified market power rents of around $5.4 billion from 2010 to 2016.
- Ireland, Wallace & Associates (IWA) Economic Profit Analysis (EPA) found Meridian Energy earned around $2 billion in excess economic profit from 2016 to 2021. Analysis by IWA of Contact Energy found little evidence of substantive excess economic profit.
- The Electricity Authority's 2021 wholesale market review identified economic withholding and price discrepancy of around $38/MWh from 2018 to 2021, with an average value of over $1 billion p.a.
- In February 2022, investment and advisory group Jarden identified around $1.9 billion per annum in unexplained pricing.
- Work by MDAG discusses the issues with market concentration, noting that:

  > *"this means the provision of longer-term flexibility services would become more concentrated among parties with flexible hydro generation capacity, all other things being equal".*
  >
  > *"Nonetheless, a significant thinning of competition in the provision of longer-term flexibility services appears likely with most flexibility being held by parties with the major hydro generation."*[23]

  This highlights that market concentration issues are likely to get worse, not better, as more renewables enter the generation mix.

29. This body of analysis will continue to hang over the wholesale market until there is a rigorous examination of the issue of market power and excess rents, using independent analysis. As MDAG has stated, this issue will only get worse. This burden will fall on all consumers, at a time when many are already feeling the cost-of-living crisis and struggling with energy bills.[24]

30. **MEUG strongly encourages the Government to look at this issue now, before it gets substantially worse, harming both residential and business consumers**.

[22] As summarised in the MEUG Chair Update, March 2022, http://www.meug.co.nz/node/1190
[23] Page 77, MDAG, https://www.ea.govt.nz/documents/1006/MDAG_-_Price_discovery_in_a_renewables-based_electricity_system_-_options_paper.pdf
[24] https://www.consumer.org.nz/articles/profits-surge-for-new-zealand-s-gentailers

Factors driving this disparity with wholesale prices

31. MEUG believes that there are several factors contributing to or driving this disparity between wholesale electricity prices and the cost of generation:

a) **Structure of the electricity market:** The design of New Zealand's electricity market sees the price of all electricity supplied being set by the price of the last unit of electricity dispatched to meet demand. This design creates perverse incentives to keep the supply of generation available limited to keep prices high and allow generators to get a return on their investments (basic economic principles).

b) **Impact of the ETS:** Where thermal generation (coal or natural gas) is the last unit dispatched to meet half hourly demand, the price for this unit of energy incorporates the cost of emissions, via the Emissions Trading Scheme (ETS) cost into the offer price. This leads to every generator dispatched being paid the price set by thermal (including the ETS "uplift"), regardless of whether they are renewable or thermal generation.

This uplift can often by quite significant, with the ETS component sometimes contributing up to almost 50% of offer price (as illustrated in the box below[25]). With the ETS expected to be the primary tool to drive change, this could have a considerable impact on the price of electricity, which could impact businesses and residential consumers (estimated between $60 and $100 per MWh).

ETS price impacts for thermal generation

At present, there is a range of emissions factors for thermal generation:

- Huntly coal has EmF of 1.101 tCO2/MWh
- Lowest gas emitter HLY5 has EmF of 0.4 tCO2/MWh.

At today's NZU price of $70, this gives an ETS uplift of $71 and $28 respectively.

Last week, the spot market averaged $137.27/MWh at Otahuhu, up from $131.14/MWh the week before. Half hourly prices ranged between $0.12 and $235.72/MWh.

We note NZU prices are expected to rise increasing the impact over time. The recent changes to NZ ETS auction settings have markedly increased the price controls for 2024 to:

- Price floor $64.00 (from $35.90)
- Tier 1 CCR trigger price$184.00 (from $91.61 single tier)
- Tier 2 CCR trigger price $230.00

With significantly escalating prices controls regulated out to 2028.

[25] This data has been sourced from the em6 carbon methodology https://www.ems.co.nz/em6-carbon-methodology/, Mercury Gig Guide, 30 October 2023, and https://www.legislation.govt.nz/regulation/public/2023/0238/latest/LMS893595.html

c) **Market concentration / market power**: While the role of thermal in the wholesale market is expected to decrease in coming years, analysis by MDAG predicts that market concentration will become even more pronounced. The analysis above demonstrates that there is a significant level of unexplained pricing or possible excess profit arising from the NZ electricity market.

To date, government actions have focused around encouraging new entrants. This will have some benefits, but anecdotally we understand the Electricity Authority's own analysis suggests the total market share of the big four gentailers is likely to reduce by only 5-7% due to new entrants entering the generation market. MEUG considers that the Government must prioritise work in this space. We also consider that it will be important to consider and incorporate the findings of the final MDAG report when released in December 2023.

Recommendations

32. Addressing the competition issues in the wholesale electricity market is the key priority from MEUG's perspective. We recommend that **Government investigate the disparity between wholesale electricity prices and cost drivers, to affirm whether the market is working as it should**. It is essential that Government understands the underlying issue(s) prior to progressing to any possible market adjustments or interventions. This is a key priority and should be actioned without delay.

Managing the move away from fossil fuels to renewables – transition or crisis?

33. MEUG considers that there are significant overlaps and linkages across the issues discussed in Chapter 2 (accelerating supply of renewables), Chapter 3 (ensuring sufficient firm capacity during the transition) and Chapter 4 (managing slow-start thermal capacity during the transition) of the MBIE discussion paper, making it difficult to comment on each chapter in isolation. There are also considerable connections with the issues discussed in Chapter 5 (workably competitive electricity markets) and our comments in the section above.

34. At the crux of these chapters is the question and assumptions around how the electricity system transitions away from fossil fuels and to a greater level of renewable electricity generation. Much analysis to date paints this as a managed transition; however, MEUG challenges this. We believe that this issue is much more critical and requires a greater degree of urgency, as there are several key assumptions that could lead to instability of our electricity system. MEUG highlights the following points:

a) The rate of new electricity generation entering the market has not kept up with the rate of electricity demand. Most of the electricity generation entering the market in recent years has been wind, geothermal and solar, [26] with the market now turning to offshore wind. Intermittent generation is not always available to meet demand (when New Zealand faces calm and grey conditions). Its impact on the market has been discussed through recent Electricity Authority workstreams:

- The consultation paper addressing forecasting provisions for intermittent generators notes that "*inaccurate intermittent generation forecasts create uncertainty for other participants, who need to make generation or*

[26] We note an Electricity Authority article from 14 February 2023, https://www.ea.govt.nz/news/eye-on-electricity/new-zealands-electricity-future-generation-and-future-prices/

consumption decisions ahead of real time. Inaccuracy may particularly affect participants who need advance notice to make generation or consumption decisions (e.g., thermal generators and industrial demand-side participants)."[27]

- The consultation paper on common quality requirements under Part 8 of the Electricity Industry Code identified several issues that would arise from inverter-based variable and intermittent resources, for example, more frequency fluctuations, greater voltage deviations and increased likelihood of network performance issues.[28]

b) Thermal generation has begun exiting the market, leaving the remainder of thermal plants playing a critical role, providing capacity for firming and dry years. However, the thermal fleet is aging and requires investment to keep it up to requirements. The recent outage of the Huntly 5 400-megawatt gas turbine and one of Contact's Stratford gas peakers provide insight into the vulnerability of the system, and the timeframes to bring these aging units back into service.[29]

c) There is also a lack of gas in the market, arising from oil and gas players leaving the New Zealand market or reducing investment, following the strong signals sent to the market from the Government's oil and gas ban in 2018. Most gas volume is tied up in contracts, and reliant on the continuation of key players in the New Zealand market, primarily Methanex. In Transpower's recent review of Winter 2023, it has noted:

> *For 2024, our gas production expectations are lower than what we have seen in 2023, which increases the energy supply risk if there is a prolonged dry sequence, despite new generation commissioning and Contact's TCC unit extending its operational hours through 2024. This risk can be mitigated in the short-term by maintaining the coal stockpile, investment in additional stored gas, or gas reallocation agreements ahead of any dry sequence. In the long term, the risk can be mitigated through investment in increased gas production, or increased investment in a diverse pool of renewable resources.*[30]

While the market may be calling for increased gas production and new gas peakers to manage upcoming winters,[31] the *Gas Transition Plan* issues paper succinctly captures the current market view – "*no business currently intends to build them as the costs and perceived investment risks are too high*". [32]

d) There are limited viable alternatives to replace the use of gas and coal by thermal generators. Genesis Energy "completed a black wood pellet trial with its Huntly Rankine units in February [2023]" and is currently in discussion with potential biomass suppliers.

[27] https://www.ea.govt.nz/documents/3151/Issues__options_paper_-_intermittent_generation_forecasts.pdf
[28] Long-form report (ea.govt.nz)
[29] *Huntly 5 back in January,* 18 September 2023, Energy News, https://www.energynews.co.nz/news/gas-fired-generation/145737/huntly-5-back-january
[30] Winter 2023 Review, October 2023, Transpower, https://static.transpower.co.nz/public/uncontrolled_docs/Winter%202023%20Review.pdf?VersionId=Zxdbk14diwGA43UuzjYGV8IhGj44cbji
[31] For example, https://www.newsroom.co.nz/contact-warning-against-chaotic-closure-of-gas-power-plants
[32] Page 27, *Gas Transition Plan* issues paper.

The use of hydrogen for electricity generation is in the early stages of scoping, with Genesis Energy noting "*the manufacturers are active in the use of hydrogen for these units and could help us adapt Unit 5 for this fuel. We're monitoring hydrogen production in New Zealand with a view out to the 2030s.*"[33]

- As noted in the BusinessNZ Energy Council submission,[34] concerns run deep across the sector regarding New Zealand's current flexible capacity, or lack thereof, to accommodate the growth in electrification and surges in peak demand periods.[35] We agree with this concern. The last two winters have seen the top 10 largest peaks in demand despite record warmth, and El Nino weather conditions may further exacerbate the strain on the electricity system.
- The Electricity Authority and MBIE have not actively engaged with the sector on the key issues impacting the transition. MEUG believes both agencies are over-confident in the ability of existing market settings to effectively manage the transition. We do recognise that the Electricity Authority is taking action to increase its engagement with the sector, with early signs being positive.

35. MEUG considers that all these factors, including the issues with competition discussed above, keep the market's supply on an edge, where one big event could seriously disrupt the system. It is not clear what solution would address these compounding risks, but highlight the necessity of taking stronger, more urgent action in collaboration with the sector.

Chapter 2: Accelerating supply of renewables

36. There are several areas where we believe MBIE and Government should focus its attention, to support the goal of accelerating the supply of renewable electricity generation and reducing sector emissions, while ensuring a reliable and secure supply of electricity that meets consumer's needs. We expand on these below.

Market should drive optimal level of renewable electricity generation

37. MEUG recommends that the Government steps back from pursuing a 100% renewable electricity target by 2030. We consider that it would be more beneficial for the sector to focus on increasing the level of renewable electricity to the highest extent commercially, technologically, and operational viable, while focusing on electrifying other sectors and reducing overall emissions.

38. We consider that setting a target of 100% renewable electricity would be detrimental to New Zealand. For example, the Climate Change Commission recommended that:

> *"The Government should consider replacing the 100% target with a goal of aiming to achieve 95-98% renewable electricity by 2030. Work undertaken by the Interim Climate Change Committee (ICCC) demonstrated that moving from 98% renewable electricity to 100% renewable electricity would cost about $1,280 for every tonne of carbon dioxide abated and would result in higher electricity prices. Higher electricity*

[33] *Huntly fuel options critical – Genesis,* 13 October 2023, Energy News, https://www.energynews.co.nz/news/electricity-generation/146996/huntly-fuel-options-critical-genesis

[34] BusinessNZ Energy Council submission on MBIE's consultation package, 2 November 2023.

[35] These concerns were also set out in the article *Power shortage risks in 2024 after loss of gas-fired power plant,* Pattrick Smellie, Business Desk, Power shortage risks in 2024 after loss of gas-fired power plant | BusinessDesk

prices could make switching to electricity as a low-emissions fuel relatively less attractive.” [36]

39. The KPMG recent report *30 Voices on 2030: The Future of Energy in Aotearoa*[37] also outlined energy sector’s view on the target, with many noting that “*we don’t need a national “aspirational target”, we need an energy strategy*”. The report also noted that “*there was a wide degree of acceptance that our pathway to prosperity is not with a “turning off “philosophy, rather a joined-up approach which enables us to “invest to reduce””*.

40. The Government should focus on preparing an Energy Strategy and providing an enabling environment, then leave it to the market to determine the optimal level of renewables. Sector participants have the best knowledge of the technology options available and the challenges with maintaining a secure and reliable electricity supply. This market-led approach enables the target to evolve over time, adjusting to new technologies as they arise and how customer demands adapt.

Importance of addressing planning and RMA framework

41. There is considerable evidence that New Zealand’s planning environment and the *Resource Management Act* are having a detrimental impact on the development of new renewable electricity generation and the supporting electricity infrastructure. For example, a recent report from Te Waihanga, the Infrastructure Commission, concluded that consent processing times from 2028 will need to be 50% quicker than they are projected to be under the Resource Management Act (RMA) for NZ to meet its climate aspirations.[38]

42. MEUG welcomes the Government taking urgent action to address the issues that the electricity sector is currently facing when it seeks to develop and consent renewable electricity infrastructure.[39] This should be a key priority for the Government in the coming year, to ensure this infrastructure is built in a timelier manner.

Role of Power Purchase Agreements

43. MEUG welcomes MBIE’s discussion on the role of Power Purchase Agreements (PPAs) and how they can incentivise or bring forward new renewable generation. Some MEUG members are now looking at PPAs as an option to secure electricity at competitive prices for their businesses and supporting the growth in renewable energy.

44. Members have already made PPA investments in renewable energy opportunities. For example, in April 2023, Amazon entered a long-term corporate PPA contract with Mercury for approximately half of the real-time output of the southern section of Mercury's Turitea wind farm near Palmerston North.[40] Several members are also part of the Renewable Electricity Generation Project (REGP),[41] which collectively tenders for PPAs with renewable electricity generators across New Zealand. It is currently

[36] https://www.climatecommission.govt.nz/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf
[37] https://assets.kpmg.com/content/dam/kpmg/nz/pdf/2023/10/30-voices-on-2030-v2.pdf
[38] Infrastructure consenting for climate targets: Estimating the ability of New Zealand’s consenting system to deliver on climate-critical infrastructure needs, Sapere, 25 January 2023, https://srgexpert.com/wp-content/uploads/2023/10/Infrastructure-Consenting-for-Climate-targets-January-2023.pdf
[39] http://www.meug.co.nz/node/1292
[40] https://www.reseller.co.nz/article/706523/aws-inks-renewable-energy-deal-mercury-power-local-data-centers/
[41] Background on REGP found here: http://www.meug.co.nz/node/1044 and https://onestepoffthegrid.com.au/nz-biggest-corporate-ppa-seeks-up-to-2000gwh-a-year-of-new-renewables/

concluding a second tender round to source interest in further PPAs.

45. As outlined in a presentation at the NZWEA 2023 conference,[42] we consider that PPAs are a positive addition to the New Zealand market. In addition to supporting the growth of renewable electricity and the establishment of new entrants in the market, they should:

- Provide access to lower and more certain pricing than the spot and futures markets.
- Help address the increasing price volatility in the market faced by market participants.
- Support businesses' focus on emissions reduction and electrification of process heat, in line with their environmental, social, and corporate governance (ESG) objectives and requirements.

46. However, from our experience to date, we have observed some barriers to an effective PPA market:

- **Increase in pricing of PPAs**: Between the first and second round of the REGP (late 2020, then early 2023), we have observed an considerable increase in prices offered through PPAs.
- **Few projects are PPA ready**: Many projects offered are still two to three years off from being built and may not even have consent. This timing misaligns with parties looking for PPAs to commence within the short term, and consenting uncertainty undermines longer-term confidence that supply can actually be delivered.
- **Financial products to manage risk and level of volume risk on buyers**: Products to help parties manage volume risk are only emerging slowly and there are often not enough projects to diversify risk (i.e., differing locations, or generation type).
- **Maturity of New Zealand market compared to other jurisdictions**. For example, the Australian market for PPAs is performing well, and is more mature.[43]
- **Role of Government entities as a purchaser of their own electricity requirements**: To date, there has been limited interest from Government to engage in PPAs. We have observed interest at a Ministerial level, but this has not flowed through to Government.

47. Transpower has recently released an insight report into Corporate Power Purchase Agreements.[44] MEUG was involved in the scoping of this report and welcomes the findings of this report. The paper helpfully identifies international approaches to "*developing a deeper and more active PPA market to support the energy transition, particularly in European and North American electricity markets*."

48. We recommend that the Strategy include an action on whole-of-Government (as a large energy user) and the electricity sector to look for opportunities to mature the PPA market. This should include scoping opportunities for Government to be involved as a purchaser, and the opportunities to group small projects together to offer PPAs of a significant volume and diversity of location / fuel type to the market.

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[42] http://www.meug.co.nz/node/1317

[43] https://businessrenewables.org.au/wp-content/uploads/2022/11/BRC-A-State-of-PPA-Market-2022-summary-slides.pdf

[44] https://static.transpower.co.nz/public/uncontrolled_docs/Corporate%20PPA%20Final%20%28publish%29.pdf?VersionId=zsFR4e7sdn73V36LkRZrL2ztLJjnJkbf

The role of thermal electricity generation through transition (Chapters 3 and 4)

49. MEUG supports an increase in renewable electricity generation but believes that gas, and in particular thermal electricity generation, will continue to play a role for the foreseeable future.

50. New Zealand has historically relied upon coal and natural gas generation to meet peak demand, to make up the shortfall from reductions in intermittent generation (wind, and solar) and to support the system through dry years.[45] Going forward, we see thermal generation no longer providing baseload energy, and moving into a peaking role.[46]

51. We note that there has been discussion around the potential need for investment into building new peaking plant. Forsyth Barr has outlined how the "*the early September [2022] cold snap highlights the need to retain Huntly's Rankine units to meet peak demand, but it also shows that New Zealand would benefit from better forms of peaking generation*".[47] Earlier this month, Mercury's generation Portfolio Manager also stated that the "*electricity system needs to build new fast-fired gas electricity generation plan now, on a similar scale to the existing Huntly power station, to avoid blackouts and to decarbonise*".[48] MEUG believes that there is still a case for gas peakers, where it has been evidenced that when they don't run, there can be extremely high prices and excessive use of market power.[49]

<u>Continued need to address New Zealand's dry year issue</u>

52. New Zealand has well-documented issues with dry years and the impact this can have on electricity supply – whether it is high prices, blackouts, or energy conservation campaigns. This led to the establishment of the "NZ Battery project" within MBIE that has been investigating the ability of pumped hydro, and alternative technologies, to address New Zealand's dry year electricity problem.

53. However, this project's strong focus on Lake Onslow has not been well received by the electricity sector. Stakeholders have criticised the proposed cost of the project ($15.7 billion), the time to build (seven to nine years) and its location (in the lower South Island, distant from peak demand in the North Island). It has also been a source of regulatory uncertainty, deterring investment in both flexible generation and storage, and stakeholders questioning how its operation would impact on the wholesale electricity market.[50]

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[45] As discussed on page 27, *Gas Transition Plan,* MBIE, https://www.mbie.govt.nz/dmsdocument/27255-gas-transition-plan-issues-paper-pdf

[46] *Ensuring a Orderly Thermal Transition,* 13 June 2023, Electricity Authority, *https://www.ea.govt.nz/documents/3148/Ensuring_an_Orderly_Thermal_Transition_6_June_20231397102.1_1.pdf* and supporting analysis *Potential demand for thermal generation in the transition to a renewables-based electricity system,* May 2023, Concept Consulting, https://www.ea.govt.nz/documents/3147/Appendix_C_-_Concept_Consulting.pdf

[47] https://www.energynews.co.nz/news/energy-security/128402/nz-needs-more-gas-peakers-forbarr

[48] https://businessdesk.co.nz/article/policy/new-gas-fired-electricity-generation-needed-now-to-reduce-emissions

[49] As discussed in Fonterra's submission on this MBIE paper, history has shown that as thermal generation leaves the market, the remaining marginal thermal generation is concentrated to set the price which also flows through to the water value for hydro generation. Also refer to https://www.energyresources.org.nz/news/reduced-natural-gas-supply-led-to-higher-prices-and-emissions/

[50] https://www.energynews.co.nz/news/pumped-hydro/135737/investigation-157b-onslow-scheme-continue

54. MEUG believes that there is still a need to address dry year risk. We therefore recommend that "NZ Battery Project" be rescoped and incorporated into the Strategy, with a focus on:

- Removing Lake Onslow from consideration as a viable option to address dry year risk.
- Focus on exploring multiple options for energy storage (i.e., batteries, further gas storage fields, greater use of hydro lakes as reserves rather than constant baseload supply), with selection of options driven by the market and the technical / commercial opportunities. We believe that decentralised and more modular solutions, located closer to consumer demand, provide a more optimal solution, rather than a single large project.
- This should include looking at how hydro generators could act as a battery in the system, rather than run as baseload, while still considering the market concentration concerns raised by MDAG.

55. This rescoped project should continue to be a priority for MBIE, with greater input from the Electricity Authority, the System Operator, and sector participants.

<u>Other potential measures to aid with the transition</u>

56. In addition to the discussion above, MEUG also has the following observations:

a) We have reservations around introducing a reserve energy scheme like the Whirinaki power plant, that was introduced in 2004. Whirinaki was set up to "*run only when the limits of the electricity system are tested by problems like low inflows to the hydro lakes, or perhaps a major generation or transmission breakdown. It [was] effectively a form of insurance against the risk of power shortages*."[51] However, Whirinaki was sold back into market, when "*in 2009 the government accepted a recommendation from the Ministerial Review of the Electricity Market that the reserve energy scheme be abolished and the Whirinaki plant sold*."[52] It was concluded that the reserve energy scheme "*reduced security of supply by encouraging market participants to rely on the then Electricity Commission to ensure security, and by discouraging investment by electricity generators in peaker plants*." We believe that these conclusions remain valid for today's market and note that both MDAG and the BCG independently concluded that this type of intervention would increase costs and undermine investment incentives without materially improving energy security.

- We consider that consideration should be given to a new ultra-fast reserves class for participants that can respond within a cycle, as raised in Fonterra's submission.[53] Fonterra note that in overseas jurisdictions, the deployment of utility scale batteries has been shown to successfully catch disturbances in the grid by both injecting and removing energy as the frequency bounces.

[51] https://www.beehive.govt.nz/release/whirinaki-power-plant-adds-electricity-supply-security
[52] https://www.beehive.govt.nz/release/whirinaki-plant-be-sold
[53] See Fonterra's submission on MBIE's issues paper *Measures for transition to an expanded and highly renewable electricity system,* 2 November 2023.

- The electricity sector should continue to explore opportunities to convert thermal plant over to renewable fuels, such as that being trialed at Huntly with biomass. As noted above, Government should focus on providing a supportive environment to enable this and leave it to market to determine what efficient alternatives will be available at scale required.
- We would support a requirement for market participants to disclose information on thermal plant closure. Market participants are already required to provide information on thermal fuel risks. This further information would provide greater insight into the market and forward planning of any security of supply risks that could arise from exits.

Chapter 5: The role of large-scale flexibility

57. MEUG welcomes the discussion of large-scale flexibility and demand response as one of the mechanisms that can help support the transition of the electricity market. However, we do not believe that the current market mechanisms are sufficient to incentivise large-scale participation by businesses.

58. Considerable work has been undertaken by the electricity sector on the merits and benefits for greater demand side participation in the wholesale market. The MDAG[54] and Dr Batstone's most recent reports[Error! Bookmark not defined.] have added to this body of knowledge, outlining the potential increase in demand-side flexibility (DSF) that could be enabled through improvements in smart controls and technology, and quantifying the scale of potential benefits to the wholesale market.[55] For example, as outlined by MDAG, there is a broad set of benefits:

> *"For example, if an additional 5-6% of system load was responsive (as per the enhanced demand flexibility case) that would save around $120 to $170 million per year in generation system costs (i.e., excludes any additional savings from reduced network costs).*

<u>Discussion of current regulatory measures</u>

59. However, despite the insight we have into demand side response and the potential benefits, it is clear that very little progress has been made over the last 20 years. As outlined by Dr Batstone, Norske Skog was the only participant to have registered as a "dispatch capable load station" in the New Zealand market under the prior arrangements and ripple control of hot water, although reduced in scale, has historically been the only significant demand-side tool used across the country.

60. The Electricity Authority recently introduced new market mechanisms, dispatchable demand and dispatch notification, which built on the welcome introduction of real time pricing. A summary of this measure is provided in Figure 4 below. This mechanism is intended to encourage demand side participation. But to date, we understand that there are only two market participants involved with this mechanism, and with MEUG members seeing the cost of disruption to production exceeding any potential financial incentives with the current scheme.

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[54] *Price discovery in a renewables-based electricity system – Options paper*, Market Development Advisory Group, 6 December 2022, https://www.ea.govt.nz/assets/dms-assets/31/MDAG-options-paper-final-2.pdf
[55] See pages 11 – 13, *Enhancing wholesale market demand-side flexibility: Framework for Option Development*, November 2022, Stephen Batstone, https://www.ea.govt.nz/assets/dms-assets/31/DSF-framework-paper-FINAL-1.pdf

Figure 4: Extract from Electricity Authority guide on Real Time Pricing[56]

From April 2023 the dispatch notification product will enable the inclusion of Distributed Energy Resources and aggregated demand management in the wholesale market, subject to approval by the system operator. Enhancements to dispatchable demand will allow large industrial consumers to bid in demand management in a way that better suits the physical constraints of their plant and processes.

This will enable:

- better management of spot price volatility
- an alternative to financial hedges to manage spot price exposure
- better outcomes for large industrial participants bidding dispatchable demand and/or offering interruptible load to the instantaneous reserves.

61. Over the last year, two of MEUG's members have entered into demand response arrangements through bi-lateral agreements:

- **NZ Steel** negotiated a Power Purchase Agreement with Contact Energy that provides them with 30MW average of renewable electricity in a flexible off-peak arrangement which lets them scale down production in times of peak demand or supply shortages.[57]
- **New Zealand Aluminum Smelter (NZAS)** and Meridian Energy Limited have entered into an agreement for the smelter to reduce its consumption of electricity at the Tiwai Point smelter by up to 50MW and provide demand response flexibility during 2023 and 2024.[58]

62. This is a positive step forward, and we note that this type of arrangement is also being pursued by other parties.[59] For example, on 30 October 2023, Meridian has partnered with Open Country Dairy and secured an agreement for demand flexibility:

> *"Open Country Dairy will be compensated for reducing demand by up to 27MW when required to remove pressure from the electricity systems, such as in winter peaks or periods of low hydro storage"*[60]

<u>**Current incentives are insufficient**</u>

63. While successful bi-lateral arrangements have been made, MEUG believes that the current market mechanisms for demand response are insufficient. We do not consider the benefits of participating in the market currently outweigh the costs placed on businesses from participating:

a) Large industrial users, such as MEUG's members, are likely to require additional equipment and systems to be able to effectively engage in the market and meet the requirements of the System Operator. Many do not have 24 / 7 control rooms, meaning additional resourcing could be required.

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[56] https://www.ea.govt.nz/documents/3430/RTP_brochure_cqYyDmr.pdf
[57] Page 29, *30 Voices on 2030: The future of energy in Aotearoa,* October 2023, KPMG, https://assets.kpmg.com/content/dam/kpmg/nz/pdf/2023/10/30-voices-on-2030-v2.pdf
[58] https://cdn.sanity.io/files/jhthdezs/production/61dd7e5f00392c807fd140fa99d145ee1932787d.pdf and https://www.meridianenergy.co.nz/news-and-events/meridian-and-nzas-demand-response-agreement

[60] https://www.meridianenergy.co.nz/news-and-events/supporting-the-decarbonisation-of-open-country-dairy

b) While businesses save electricity during a period that they are dispatched off, they still need to meet the ongoing operational costs incurred during the period – i.e., staff, overheads.

c) If businesses are dispatched off for significant periods, this can affect the operation of equipment and impact on business delivery (i.e., meeting orders for external clients).

64. There is something intrinsically wrong with the electricity market, if we are asking businesses on a regular basis to stop consuming electricity and sacrifice productive activity and revenue, to balance the electricity system due to a lack of investment in generation. MEUG has met with Electricity Authority staff to discuss our concerns and to start discussions around alternative ways forward that would better incentivise large user participation.

65. Primarily, MEUG consider that **demand side response arrangements should be mutually beneficial and balance system needs with economic productivity.** We consider that demand-side participants should be able to receive a form of payment that reflects the full benefits of the service provided and reflects the costs to the participant (i.e., lost production). This could be equivalent to the spot market electricity price for the volume participants have bid into the price stack at the final settlement price by the System Operator (i.e., the same as a generator). We believe that this would allow clearer price discovery in the electricity market[61] and would incentivise large users to make the types of investments needed to partake in the market.

66. MEUG observes that many consumers, including our members, would actively respond to the regional coincident peak demand (RCPD) signals under the previous Transmission Pricing Methodology (TPM) and reduce demand. The RCPD process provided a clear signal, where costs were known in advance, with Transpower previously estimating that responses to RCPD signals contributed to approximately 2% reduction in gross demand. In contrast, when considering offering demand side response into the wholesale market, consumers do not have visibility of the spot price beyond that of the first trading period where an offer is made - – in reality, beyond the next SO (nominally 5 minute) dispatch period. This makes it difficult for a possible participant to estimate the impact on a consumer or business over multiple trading periods. This is where the concept of settlement per dispatch period, rather than trading period, may be more beneficial.

67. We encourage the Electricity Authority to look at improvements to the existing mechanisms, including progress made in other countries. In its recent submission to the Electricity Authority, Enel X New Zealand mad several useful observations about the role of dispatch notification and dispatchable demand mechanisms in other jurisdictions, and whether they are the most effective mechanism for incentivising participation in the electricity market:

> *"…..demand bidding mechanisms have failed to see any meaningful uptake. This is because the benefits rarely outweigh the costs, complexity, and risks of participating……In Enel X's view, there are other, more effective ways to bring demand flexibility into the energy market."*[62]

[61] http://www.meug.co.nz/node/1324

[62] https://www.ea.govt.nz/documents/3848/Enel_X_submission_-_Dispatch_notification_enhancement_and.pdf

68. MEUG supports these observations and views raised by Enel X. We also refer MBIE to the work done by the Australian Energy Market Operator (AEMO) on implementing a Wholesale Demand Response (WDR) mechanism in the National Electricity Market (NEM):[63]

> *"The WDR mechanism allows demand side (or consumer) participation in the wholesale electricity market at any time, however, most likely at times of high electricity prices and electricity supply scarcity. 'Demand Response Service Providers' (DRSP) classify and aggregate the demand response capability of large market loads for dispatch through the NEM's standard bidding and scheduling processes.*
>
> *The DRSP receive payment for the dispatched response, measured in Mega-Watt hours (MWh) against a baseline estimate, at the electricity spot price."*

69. We consider that there is merit in the Electricity Authority learning from the introduction of this mechanism and the insights from the AEMO.

Recommendations

70. Given the points raised above, we recommend that the Electricity Authority, in conjunction with MBIE and the System Operator, look at improvements to the current market mechanisms to ensure that **demand side response arrangements are mutually beneficial and balance system needs with economic productivity.** This should involve work on measures where participants are fairly compensated, where settlement could be over the dispatch period (not half hour trading period), and where learnings from others markets such as AEMO could be incorporated. There are also learnings that can be garnered from the bi-lateral agreements currently in place and why these may be preferable to market measures.

Investment in electricity infrastructure to support the transition – affordability issue

71. To enable the level of new generation forecasted to enter the market and to meet the increasing demand for electricity, significant investment is required in both the transmission system run by Transpower and the distribution networks run by 27 electricity distribution businesses (EDBs).[64] Boston Consulting Group (BCG) estimated in their 2022 report that delivering the electricity system needed for the future will require an unprecedented investment of $42 billion in the 2020s, including:

- **$8.2 billion in transmission infrastructure** to enable new renewable and flexible generation. Investments in key projects like Central North Island, Wairakei Ring and an additional HVDC cable will be critical.
- **$22 billion in distribution infrastructure** to enable electrification in the 2020s and prepare networks for rapid electrification and multi-directional flows of electricity in the 2030s. Total investment needed in 2026–2030 is forecast to be 30% higher than 2021–2025.[65]

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[63] https://aemo.com.au/en/initiatives/trials-and-initiatives/wholesale-demand-response-mechanism and https://aemo.com.au/-/media/files/initiatives/submissions/2020/wdrm/wdrm-high-level-design-june-2020.pdf

[64] https://www.ena.org.nz/about/members/

[65] Page 3, Boston Consulting Group. (October 2022). *The Future is Electric - A Decarbonisation Roadmap for New Zealand's Electricity Sector*. Available at: https://web-assets.bcg.com/b3/79/19665b7f40c8ba52d5b372cf7e6c/the-future-is-electric-full-report-october-2022.pdf

72. This will require a significant uplift in skilled workforce across the electricity sector to deliver this scale of investment. This is a key issue that both Transpower and EDBs are focusing on, with the Independent Verifier's report on Transpower's next regulatory control period (RCP4) noting:

> *Transpower has reasonable plans in place to acquire the resources to deliver RCP4 on the above components. However, it is likely that Transpower will face significant competition for skilled and experienced electricity transmission industry resources from external companies and jurisdictions that offer greater renumeration.*[66]

73. The discussion of attracting talent and growing a skill base was also raised in KPMG's recent report *30 Voices on 2030: The Future of Energy in Aotearoa.*[67]

74. Importantly, this will see **an increase in transmission and distribution costs for all consumers**, in an environment within which wholesale electricity prices have already more than doubled in recent years. The outgoing head of the Electricity Networks Association forecast that households will be "*paying twice as much as they do now on electricity within five years*"[68]

75. The **key question will be how increasing costs are recovered from the same base – electricity customers**. Under the current Part 4 framework, Transpower and the price-quality regulated EDBs[69] are allowed to recover the full costs of operating their networks via their maximum allowable revenue determination. It is the Transmission Pricing Methodology (TPM) for Transpower, and the various Distribution Pricing Methodologies (DPM) set by the EDBs that set out how these costs are shared amongst the different consumer groups and recovered over time.

76. We consider that there are several improvements that could be made to the pricing methodologies to ensure that these decisions are communicated well to consumers, that the methodologies are transparent, and customers feel that costs are allocated fairly and representatively across different types of consumers. We set out these recommendations in the sections below. As with the wholesale electricity prices, it is important transmission and distribution pricing reflects the cost of electricity delivery more closely, if the market is to retain consumer confidence in the sector.

77. Over the next regulatory period, we expect that there is going to be increased discussion around the approach of "just in time"" delivery of infrastructure, where build follows demand, versus building ahead of time or "anticipatory investments" that will support and enable expected growth. We question whether the Commerce Commission's Part 4 regime is designed to adapt to this type of approach – and deliver growth at a pace that meets customers' needs, while ensuring an affordable and reliable supply

78. We recommend that the Government work with Transpower and the EDBs to ensure that there is transparency around infrastructure pricing, consumers can have confidence that costs are allocated fairly, and transmission and distribution prices reflect the cost of supply.

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[66] https://static.transpower.co.nz/public/2023-10/Independent%20Verifier%20stakeholder%20presentation%2010%20and%2011%20Oct%202023.pdf?VersionId=FQgYEkVQYWjxfiGXOLtjXDtANRFRGczf
[67] https://assets.kpmg.com/content/dam/kpmg/nz/pdf/2023/10/30-voices-on-2030-v2.pdf
[68] https://www.stuff.co.nz/business/132006257/household-electricity-bills-will-double-over-5-years-forecasts-departing-lines-association-boss
[69] Consumer owned electricity distribution businesses are exempt from price-quality regulation, https://comcom.govt.nz/regulated-industries/electricity-lines/our-role-in-electricity-lines/consumer-owned-electricity-distribution-businesses

Chapter 7: A transmission system for growth

79. Many of MEUG's members are directly connected to Transpower's network, while others pay their transmission charges via their distributor or retailer. There are several transmission-related issues that we consider should be addressed through the Strategy, as set out below.

Progressing the Transmission Pricing Methodology (TPM)

80. The introduction of the new TPM and associated charges from 1 April 2023 has had a significant impact on the sector. A key concern from MEUG's is the pass-through of transmission charges from distributors, and the extreme price increases that many members with Time of Use (ToU) sites have faced from this change in TPM. Communication of this change before 1 April 2023 has been varied from EDBs, with increases from 40% up to 190% in transmission charges observed, often with limited explanation.

81. We remained concerned with the removal of Regional Coincident Peak Demand (RCPD) and the impact that this change is having on peak demand. We refer to the Authority's report that found that:

> *"….underlying peak consumption has been increasing. Peak consumption (the highest 300 total consumption trading periods) has been growing by between 10-20MW (or 0.4%) per year over the last nine years. However, the increase in peak consumption in 2022 was higher than this underlying growth would suggest and not accounted for by colder weather, given 2022 was a relatively warm year".*[70]

82. The approach with the TPM also seems counter to what the Authority is seeking through its work on distribution pricing.[71] We consider that this is an issue that the Authority must continue to monitor, to ensure that consistent signals are sent around the impact of peak electricity usage on the system. Transpower's 2018 analysis[72] provides an example of what an increase in peak demand can mean for network investment.

83. Members are also finding it increasingly difficult to forecast future TPM costs due to the more complex approach taken with the new TPM. This adds an additional layer of complexity when looking at decarbonisation and electrification investments, with businesses unclear on future input costs.

Development of transmission infrastructure

84. As noted above, we support the Government taking urgent action around the RMA to address the issues that the sector is facing when they seeks to develop and consent renewable electricity infrastructure.[73] It is critical that Transpower can build infrastructure in line with the timeframes for bringing new generation assets online and the growth of electricity demand. At present, the timeframes to consent a new transmission line are considerably greater than the time required to build new generation (i.e., a windfarm). This timing needs to be better aligned.

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[70] Page 2, The impact of the RCPD charge removal on peak demand, Electricity Authority, https://www.ea.govt.nz/documents/2338/The_impact_of_the_RCPD_charge_removal_on_peak.pdf
[71] Refer to this paper: https://www.ea.govt.nz/documents/3367/Issues_Paper_-_Target_reform_of_Distribution_Pricing.pdf
[72] https://tpow-corp-production.s3.ap-southeast-2.amazonaws.com/public/uncontrolled_docs/TCC-workshop-pre-reading-2018-Grid-Owner-case-studies-relating-to-RCPD-removal.pdf?VersionId=azO7Mc220FXGzEINn1p3u_Sd_Q0TAyyK
[73] MEUG submission to MBIE - Renewable generation and transmission | Major Electricity Users' Group

Importance of resilience

85. System resilience will become increasingly more important as more sectors rely on electricity to meet their energy needs, and New Zealand faces more climate-related weather events, such as Cyclone Gabrielle. We support the Government's work on critical infrastructure, including DPMC's work on its critical infrastructure workstream[74] and the New Zealand Infrastructure Commission's development of Rautaki Hanganga o Aotearoa, New Zealand's infrastructure strategy.[75]

86. It is encouraging to see Transpower adapt its approach, with a focus on a resilience programme for the Regulatory Control Period commencing in 2025 (RCP4). We query whether the sector needs to look at the current "N-1" security approach and whether this is sufficient during natural disasters. As noted in Fonterra's submission,[76] its' two circuits on two separate transmissions lines running side by side might technically be N-1, but if they are both exposed to the same natural hazard potential, then they are not fully N-1. We consider that this is a matter to be considered through Transpower's Net Zero Grid Pathways (NZGP) programme.[77]

Evolution of the Part 4 regime

87. As discussed above, the regulatory framework established under Part 4 of the *Commerce Act 1986* was established at a time when there were relatively stable market conditions. The electricity market has now changed, with the need for much greater generation and infrastructure to meet the growing demand from consumers, and new sectors that are looking to electrify.

88. We recognise that the Commerce Commission is concluding the 2023 Input Methodologies (IMs) review and beginning consultation on Transpower's RCP4, with the publication of a process, framework, and approach paper.[78] However, we question the level of change that may be pursued through this work, as we have felt that there has been limited engagement with the Commission to date and low visibility around how work is progressing. We noted these concerns in our cross-submission to the Commerce Commission in August 2023:

> *MEUG is concerned that stakeholders have not been given sufficient time to provide detailed and robust input on the 2023 IMs review. This consultation comes at a time when several other government agencies are also consulting on energy and climate change policies that will affect both regulated monopolies and the broader energy sector – for example, the Electricity Authority's targeted reform of distribution pricing, the Ministry of Business, Innovation and Employment's (MBIE) consultation package on advancing the energy transition and the New Zealand Emissions Trading Scheme (NZ ETS) review.*
>
> *Stakeholders such as MEUG, alongside gentailers and EDBs have also had to review the large volume of consultation material and submissions relating to the draft IMs decisions for EDBs, alongside the proposals for Transpower. This has required MEUG*

[74] https://consultation.dpmc.govt.nz/national-security-group/critical-infrastucture-phase-1-public-consultation/user_uploads/dpmc--summary-dd--strengthening-the-resilience-of-ci.pdf
[75] https://media.umbraco.io/te-waihanga-30-year-strategy/mmahiykn/rautaki-hanganga-o-aotearoa-new-zealand-infrastructure-strategy.pdf
[76] See Fonterra's submission on MBIE's issues paper *Measures for transition to an expanded and highly renewable electricity system,* 2 November 2023.
[77] https://www.transpower.co.nz/projects/net-zero-grid-pathways-programme-nzgp
[78] https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpowers-price-quality-path/2025-transpower-individual-price-quality-path

to focus on a selected number of key issues, and often provide only high-level comments.

It is disappointing and telling to see that only one party (Vector) besides Transpower was able to provide a submission on Transpower's draft IMs determinations.[79] This brings into question whether the Commission has received sufficient feedback to inform its decisions for the IMs review"[80]

89. These concerns were echoed by several parties including Vector and Electricity Networks Aotearoa (ENA). We would welcome a more collaborative working approach with the Commerce Commission, as we move forward with action towards the Strategy. We believe that this will enable the Commission to garner more detailed input and insight from the sector and consumers, and test out regulatory approaches in a timelier manner.

Chapter 8: Distribution networks for growth

90. As outlined in recent submissions to the Electricity Authority and the Commerce Commission, MEUG considers that there are several issues that need to be explored in depth with electricity distribution, to ensure it can support and enable an effective energy transition. We summarise each of these below, with links to prior submissions where we have discussed the issue provided i:

    a) There is a **lack of transparency around how distribution pricing is established**, **including how costs are allocated amongst customer groups**. More accessible pricing information is essential for industrial and business customers as they expand and electrify their operations and seek cost-reflective, efficient pricing.[81] MEUG acknowledges the concern that some consumer groups may be paying more than their share, as evidenced in the 2019 Electricity Price Review,[82] and as discussed in our submission on Wellington Electricity pricing.[83]

    We set out below some observations of recent experiences across our members regarding yearly pricing updates and EDB pricing methodologies:

    > *"We have observed widely different pricing approaches adopted by EDBs. Some EDBs simply send out letters setting out the new prices for the coming year, with no consultation and limited explanation ("take it or leave it" approach).*
    >
    > *In contrast, some EDBs, such as Powerco, take the time to meet with customers and consult openly on their pricing. This often involves a clear presentation that steps through the drivers for pricing changes and the methodology.*
    >
    > *Some EDBs have indicated that the percentage of price increases not been equal across all customer segments and residential increases have been lower.[84]"*

[79] MEUG advised the Commission that it was unable to finalise a submission on the Transpower IMs Determinations by 26 July 2023, and therefore would only be able to provide comment through a cross-submission.
[80] http://www.meug.co.nz/node/1310
[81] http://www.meug.co.nz/node/1319
[82] Paragraph 6.12 of the Issues Paper.
[83] Paragraph 6.14 – 6.15 of Issues Paper.
[84] MEUG submission to the Authority - Targeted reform of Distribution pricing | Major Electricity Users' Group

b) There is **inconsistency with how EDBs operate across regions**, including how they consult and share information on distribution pricing. These issues are particularly apparent for MEUG members who have operations across the country (for example, Fonterra and Woolworths), and it highlights the variation in both the performance and customer-focus of EDBs. There has been a consistent focus on standardisation, with both the Electricity Authority and Electricity Networks Aotearoa making positive progress on this matter.

c) There is a need to **improve the connection processes** for new customers, given the increase in demand, particularly from electrification of transport and process heat. As the Authority has noted, there is a great variation in the share of capital contributions required by EDBs, and some EDBs have concerningly required new customers to "*contribute to the cost of upgrading capacity beyond their immediate connection*."[85]). This is the much discussed "first mover disadvantage" issue.

MEUG members have experienced this issue when working on both greenfield and brownfield projects, with EDBs requiring members to pay disproportionately high costs to expand a network's overall capacity in an area (beyond what is needed for a particular project or site. Also, with large Time of Use (ToU) sites, pricing is most often "price on application" (POA), with members noting that the process can be very uncertain.

The connection process was an area of debate through the recent consultation on the Commerce Commission's draft decisions for the 2023 IMs review, and the specific proposal to introduce a large customer connection "(LCC) mechanism. As noted in our submissions[86] to the Commerce Commission, we support a new LCC mechanism that can "provide a timelier option and process for customers looking to enter into large contracts with EDBs".

d) There is need for **greater information on network capacity and visibility on the low voltage network**. For MEUG members, it is important to understand what capacity is available on the distribution network and areas of possible congestion or system weakness, as we look to establish or grow operations, or convert process heat over to electricity.

We support the Commerce Commission's proposed information disclosure amendment that would require EDBs to provide information on the worst performing feeders on their networks. This measure will further enable the Commission to track EDBs progress addressing weak areas within their network and enable more informed discussions around current and future expenditure directed towards strengthening and maintaining the network.

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[85] Paragraph 7.16 of the Issues Paper.

[86] MEUG's primary submission here https://comcom.govt.nz/__data/assets/pdf_file/0021/323139/Major-Electricity-Users-Group-MEUG-Submission-on-IM-Review-2023-Draft-Decisions-19-July-2023.pdf and cross-submission here http://www.meug.co.nz/node/1307.

One emerging issue is the level of visibility EDBs have over the demand response arrangements and DER operating on their network, and the impact this is having on operations of their networks. For example, in a recent submission, ENA noted that:

> *As more consumers' distributed energy resources (DER) are managed in response to wholesale market signals, EDBs need visibility of the individual resource participating in the dispatch notification process, its location on the network and the aggregator that controls that resource.*
>
> *To avoid risks to consumer safety and network assets, EDBs will need a way to communicate to aggregators which actions can safely be accommodated by the host network, at that location and point in time. Throughout the development of the dispatch notification process, there appears to have been an incorrect implicit assumption that the actions of aggregators will not impact EDBs' networks. This is not the case, especially at the low-voltage level; where network headroom is dynamic and can quickly change (e.g., due to car versus pole outages).*[87]

Alongside this issue, we support the Electricity Authority's looking at how and what data Metering Equipment Providers provide to distributors and flexibility traders, to enable greater innovation in the market and ensure greater visibility over network operation.[88]

- **Evolution of the Part 4 regime:** The case to evolve the Part 4 regime for EDBs is as applicable as it is for Transpower. EDBs need a regime that is more adaptive to the current growth in demand and action on decarbonisation and can enable EDBs to respond to customer requests more effectively.

  In the recent IMs review consultation process, MEUG outlined our support for refinements to DPP reopeners, as we believe that the DPP reopener mechanism is one way to deal with the uncertainty that EDBs are facing in their operating environment, while still ensuring that EDBs' expenditure is adequately scrutinised by the Commission. We suggested several improvements that would provide consumer groups more insight into the process.[89]

91. We consider that these issues need to be addressed in depth, before moving to introducing any further solutions. There are already several workstreams underway at the Electricity Authority and the Commerce Commission, as well as proactive work led by the ENA and its members. It is important for the sector to leverage off this existing work, make sure we coordinate action across the EDB sector, focus on setting clear objectives for the work and what we look to achieve over what timeframe, and ensure that the customer perspective is considered at all stages.

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[87] https://www.ea.govt.nz/documents/3843/ENA_submission_on_dispatchable_load_enchancement.pdf

[88] We refer MBIE to the Electricity Authority decision paper *Delivering key distribution sector reform: Work programme*, 16 October 2023, https://www.ea.govt.nz/documents/3929/Work_programme_Oct_231406907.13.pdf. This sets out the work that the Electricity Authority intend to do in the distribution area to response to identified challenges.

[89] http://www.meug.co.nz/node/1302

Government arrangements to support the energy transition

92. MEUG would like to convey one point, regarding the ideas and concepts discussed in Chapter 9 (Is the government's sustainability objective adequately reflected for market regulators?) and Chapter 11 (Setting priorities and improving coordination).

93. Across the energy sector, there is a perception that government agencies or regulatory bodies may not be addressing the key issues facing the sector, that there is an unwarranted optimism in a smooth transition, and whether some policy and regulatory interventions will operate successfully in practice. There is also discussion of some overlap in regulatory functions (i.e., between the Electricity Authority and the Commerce Commission, particularly in the EDB space[90]) and whether greater government direction would be achieved through the establishment of a Ministry of Energy.[91]

94. Rather than looking at structural changes, or adding additional government frameworks or mechanisms, MEUG recommends that the Government focus on making the existing government arrangements work.[92] We consider that this will require:

    a) A clear focus on problem definition, before moving to policy or regulatory options.

    b) A need to engage with stakeholders throughout the process – from policy scoping through to implementation of options.

    c) The need for cross-government projects or working groups, where there is an overlap in responsibilities.

    d) The continued use of sector advisory groups, such as the MDAG and the Security and Reliability Council.

    e) Resourcing better aligned to the key priorities within each agency, and a focus on regularly reviewing projects at completion, and monitoring progress and learnings.

    f) Ensuring a diverse customer voice is considered in policy decisions, with energy affordability and economic productivity properly weighted in decisions.

95. We have observed positive improvements across government agencies over the last year, but it is important that MBIE and regulatory agencies continue to focus on successful delivery so that we can deliver on the net-zero emissions target by 2050.

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[90] For example, Contact Energy has stated that "there are features of connection costs that overlap with the powers of each of these organisations (Electricity Authority and Commerce Commission), and slowly batting consultation papers back and forth is likely to lead to an inefficient and lengthy process", submission here: https://www.ea.govt.nz/documents/3585/Contact_Energy_-_Targeted_Reform_of_Distribution_Pricing_-_Submission_Aug_2023.pdf

[91] As raised by Vector, see https://www.stuff.co.nz/business/130286785/ministry-of-energy-needed-to-pave-way-for-42b-of-investment-says-vector

[92] This is consistent with the the findings of the 2019 Electricity Price Review, which found that adding to these core objectives with other non-discretionary considerations would pull them in too many directions, require difficult trade-offs between competing objectives, and blur accountability.

2. Measures for implementing a ban on new fossil-fuel baseload electricity generation

Key recommendations from MEUG

- MEUG does not believe that there is a need for a ban on new fossil-fuel baseload electricity generation, to meet the Government's emissions targets. We consider that the market, and the price signals through the ETS, will determine the optimal electricity generation mix, and the role that thermal generation plays in the foreseeable future.
- If the Government decides to proceed with this ban, we recommend that co-generation is fully excluded from the scope of the ban. Co-generation is an efficient choice for businesses, maximizing energy streams by using waste streams to get heat or electricity.

Market will drive the optimal level of thermal generation

96. MEUG does not believe that the Government needs to ban new fossil fuel baseload electricity generation or predetermine the level of fossil-fuel electricity generation that is required in the electricity market.

97. We consider that there is an extremely low likelihood of New Zealand generators investing in baseload or slow start thermal generation going forward. Concept Consulting's modelling for the Electricity Authority's consultation paper *Ensuring an orderly thermal transition* shows results consistent with this, projecting that:

> *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, compared with the last five years, when thermal generation averaged 14% of total supply.*[93]

98. MEUG considers that the electricity market, and the price signals from ETS will see more renewable electricity generation coming onboard, displacing the fossil-fuelled generation currently used for baseload generation. However, as noted in the sections above, we consider that there will still be a clear need for gas peakers for the foreseeable future. We believe that the market and the ETS will drive the optimal mix of generation fleet to meet electricity demand, rather than Government determining a set percentage or level.

Concern with co-generation specification

99. If the Government decides to proceed with this ban, we recommend that co-generation is fully excluded from the scope of the ban.

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93 https://www.ea.govt.nz/documents/3148/Ensuring_an_Orderly_Thermal_Transition_6_June_20231397102.1_1.pdf

100. Several MEUG members currently have co-generation on their sites to meet their energy needs. For example, Oji Fibre Solutions' Tasman Mill has a Renewable Geothermal Steam Energy Co-Generator which processes steam to drive a turbine generator and then supplies process steam. New Zealand Steel also takes advantage of hot waste gas to produce energy for the production process:

> *The Cogeneration process involves the multi hearth furnace waste gas being burnt in an afterburner to provide heat for the boilers. This superheated steam from the boilers drives two steam turbines to produce electricity. The Cogeneration plant provides approximately 20% of the site electricity requirements. In 1997, the company commissioned a second Cogeneration plant, taking waste hot gases from another part of the ironmaking process, the rotary kilns. This now means up to 60% of the steel mill's electricity is generated on site.*[94]

101. The decision to use co-generation at industrial sites is driven by efficiency. Co-generation plants maximise the efficient user of energy streams produced on site, using waste streams to produce heat or electricity, meeting the multiple energy or heat requirements of an industrial or chemical process. It also reduces the need for additional energy supplies to site, reducing carbon emissions and energy costs.

102. For these reasons, we believe that new co-generation should not be banned, regardless of whether it is used for baseload or peaking requirements.

[94] NZ Steel website: https://www.nzsteel.co.nz/sustainability/our-environment/energy-resources-and-recovery/#:~:text=The%20Cogeneration%20process%20involves%20the,steam%20turbines%20to%20produce%20electricity.

3. Gas Transition Plan

Key recommendations from MEUG

- There will be an ongoing role for gas into the foreseeable future. In particular, there is a pressing need for thermal gas peakers to aid the transition of the electricity system to a greater level of renewables, while maintaining a reliable electricity supply.
- We support the investigation into the viability of renewable gases such as hydrogen and biogas for the New Zealand market, and the potential for Carbon Capture, Utilisation and Storage (CCUS). We believe decisions around these technologies and fuels should be driven by the market (economics of projects, technical feasibility) and guided by the price signals sent through the ETS.

Introduction

103. Natural gas has played an important role in New Zealand's economy. As the discussion paper notes "*fossil gas users in New Zealand are diverse, ranging from very large petrochemical plants like Methanex….through to the residential sector…within 306,000 household connections*."[95] Many of MEUG's members also use natural gas or LPG in their businesses to meet their energy needs.

104. MEUG endorses the generally held view that the role of natural gas consumption will decline over time, in line with the Government's emissions targets, and businesses will look to transition to other fuels, where economically and technologically feasible. A Gas Transition Plan can help with this shift, by setting out the Government's expectations, providing a supportive environment and ensuring the needs of consumers are considered at all steps of this transition.

Important role of gas within electricity system

105. MEUG is primarily focused on the issues paper's discussion around the use of natural gas in electricity generation. As we have noted in our comments above on the issues paper *Measures for Transition to an Expanded and Highly Renewable Electricity System*, we consider that gas, and in particular thermal electricity generation, will continue to play a role for the foreseeable future.

106. New Zealand has historically relied upon coal and gas generation to meet peak demand, to make up the shortfall from reductions in intermittent generation (wind, and solar) and to support the system through dry years. Going forward, we see thermal generation no longer providing baseload energy, and moving into a peaking role. This will be critical to firm intermittent renewable electricity generation, ensuring that we continue to have a reliable supply of electricity. This includes enabling investment in new gas peaking capability, where existing fleet is near the end of its operational life.

[95] https://www.mbie.govt.nz/dmsdocument/27255-gas-transition-plan-issues-paper-pdf

Keeping options open

107. MEUG considers that that Government should provide an enabling environment through the Gas Transition Plan by providing:

- Up to date policy and regulations to support the changes in the gas market.
- Frameworks and regulations for any new renewable gases, emerging gas markets or technologies that are demonstrated to be viable within New Zealand.
- A steady regulatory environment that enables businesses to make investment decisions with a level of confidence.

108. We do not support a prescriptive, central planning type approach to the Gas Transition Plan. We consider that it will be more effective for decisions around gas to be guided by the market (economics of projects, technical feasibility) and the price signals sent through the ETS. By putting a carbon price on gas, this incentivises parties to explore alternatives to gas (renewable gas or electrification) at the right price points, or look at options for offsetting their emissions, where there are no viable alternatives.

109. Given this approach, we support the Gas Transition Plan including support for trials of renewable gases (biogas and hydrogen) and the potential for Carbon Capture, Utilisation and Storage (CCUS). We welcome the use of trials to test the viability and suitability of these fuels and markets for the New Zealand market, with the preference for these trials to be led by the market (rather than Government driven).

110. We note that the production of hydrogen will require access to a considerable level of electricity supply. Therefore, a viable hydrogen industry would require more investment in generation and infrastructure, above that already required to meet increased electricity demand and the electrification of the transport sector and process heat. We consider that hydrogen producers would require lower priced electricity to make hydrogen a viable investment. With the current prices (both spot and futures), we query if the market conditions would support hydrogen development. We also question how the electricity sector would manage and recoup the cost of overbuilt electricity infrastructure if the hydrogen market did not eventuate to the levels expected. This could see additional costs placed on consumers.

Regulatory framework must evolve

111. As with electricity distribution and transmission, we believe that the Part 4 framework must evolve to address the market conditions facing the gas sector. In contrast to EDBs and Transpower, gas pipeline businesses may be facing a reduction in gas demand and a shortened economic life for their assets. Alternatively, if renewable gases are viable, these businesses may need to invest in further assets, possibly outside the scope of currently regulated natural gas.

112. We encourage the Gas Transition Plan to include work around the regulatory framework for gas, to ensure it can support future possible scenarios.

4. Developing a Regulatory Framework for Offshore Renewable Energy

Key recommendations from MEUG

- We support Government developing a regulatory framework to enable the introduction of offshore renewable energy into the wholesale electricity market. The introduction of offshore wind, alongside other renewable electricity generation, will be beneficial, putting downward pressure on wholesale pricing.
- MEUG does not support introducing support mechanisms specifically for offshore renewable electricity. We consider that if Government wants to continue to encourage development of renewable electricity generation, then it should not provide incentives or measures for only selected energy types (i.e., avoid picking winners) and rather provide a level playing field.

Support for regulatory framework

113. MEUG supports the development of a regulatory framework for offshore renewable energy. As outlined in our comments on the MBIE paper *Measures for Transition to an Expanded and Highly Renewable Electricity System,* introducing offshore wind will not only support the goal of reducing energy sector emissions but it will also help increase competition in the generation market, applying downward pressure on the wholesale electricity prices.

114. We understand that offshore wind can have higher capacity factors than onshore wind farms, making it a useful addition to the generation fleet. Work by the University of Canterbury and ISC has quoted high capacity factors in the range of 40 – 60%,[96] while Concept Consulting's work for NZWEA found that "*having a diversity between different types of variable renewables (i.e. having a mix of wind and solar) materially reduces the extremes of low and high generation*."[97]

115. We note the proposed development of offshore wind in the South Auckland / Waikato region proposed by BlueFloat Energy, Energy Estate and Elemental Group. A recent article states that:

> *"Offshore wind in the South Auckland-Waikato region will benefit from close proximity to the Huntly power station and the Glenbrook substation in South Auckland, next door to NZ Steel's operations, offering a direct route to the grid and the potential to provide new supplies of clean energy to consumers and industry in the Waikato and greater Auckland area.*[98]

116. We consider that New Zealand is well placed to learn from countries that are already utilising offshore wind and can adapt their learnings to optimise our regulatory framework. Like other renewable generation, it will be important for the Government to address the RMA and planning issues with consenting. It will be important to speed up the process for considering applications, as well as providing clear signals for

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[96] https://www.otago.ac.nz/__data/assets/pdf_file/0022/332446/developing-offshore-wind-in-new-zealand-technical-socio-economic-and-environmental-issues-in-relation-to-a-post-pandemic-759837.pdf
[97] https://www.windenergy.org.nz/industry-studies
[98] https://www.bluefloat.com/major-investment-planned-to-develop-south-auckland-waikato-offshore-wind-industry/

potential investors. Improvements to the RMA are also needed to ensure that the necessary transmission infrastructure can be built at similar timeframe to connect the offshore wind infrastructure.

Economics of the offshore regime

117. MBIE's paper discusses the range of economic models associated with offshore renewable energy. One feature discussed is a support mechanism where a payment flows from government to the offshore renewable energy project.[99]

118. MEUG appreciates the additional complexity of offshore wind farm development, but queries why the Government would determine it necessary to support this generation type more favourably than other renewable generation (i.e., solar, or onshore wind). In principle, we do not support the use of subsidies and do not recommend policies where government is effectively "picking winners".

119. If the Government wants to accelerate the level of renewable electricity in New Zealand, we consider that it would be prudent to look at what measures or actions (further to that discussed in the other MBIE papers) would be prudent to introduce for the entire electricity sector. While the discussion paper provides examples of Contracts for Differences (CfDs), as used in the United Kingdom, we consider that there are considerable issues to address if seeking to add this type of Government led CfD measure to the New Zealand electricity market.

[99] Chapter 6, https://www.mbie.govt.nz/dmsdocument/26913-developing-a-regulatory-framework-for-offshore-renewable-energy-pdf

Appendix A: Referenced MEUG documents and submissions

120. The followings submissions and documents from MEUG were reference during this submission and provide supporting information for our submission.

- *Dispatch notification enhancement and clarifications*, MEUG submission to the Electricity Authority, 13 October 2023
- *Targeted Information Disclosure Review (2024) – EDBs*, MEUG submission to the Commerce Commission, 14 September 2023
- MEUG presentation to NZWEA Summit, 12 September 2023
- *Targeted Reform of Distribution Pricing*, MEUG submission to the Electricity Authority, 15 August 2023
- *Draft decisions for Transpower: Input Methodologies Review 2023*, MEUG cross-submission to the Commerce Commission, 14 August 2023.
- *Open letter to Energy and Resources spokespeople*, Sector letter from key energy advocacy bodies, 26 July 203
- *Ensuring an orderly thermal transition*, MEUG submission to the Electricity Authority, 25 July 2023
- *Draft decision: Part 4 Input Methodologies Review 2023*, MEUG submission to the Commerce Commission, 19 July 2023
- *2023 Draft advice to inform the strategic direction of the Government's second emissions reduction plan*, MEUG submission to the Climate Change Commission, 23 June 2023
- *Electricity Demand and Generation Scenarios 2023*, MEUG submission to MBIE, 9 June 2023
- MEUG presentation to the Security and Reliability Council, 1 June 2023.
- *Strengthening national direction on renewable electricity generation and electricity transmission*, MEUG submission to MBIE, 1 June 2023
- *Price discovery in a renewables-based electricity system – Options paper*, MEUG submission to the Market Development Advisory Group, 6 March 2023.
- *Options to strengthen competition: Price discovery in a renewables-based electricity system*, NZIER report to MEUG to support submission to the Market Development Advisory Group, 6 March 2023.
- *Issues Paper—Updating the Regulatory Settings for Distribution Networks*, MEUG submission to the Electricity Authority, 28 February 2023
- *Wholesale Market Competition Review*, MEUG submission to the Electricity Authority, 14 December 2022
- *Wholesale market review: Comment on thermal generation*, NZIER report to MEUG to support submission to the Electricity Authority, 14 December 2022
- *Price Discovery under 100% Renewable Electricity Supply – Issues Discussion Paper*, MEUG submission to the Market Development Advisory Group, 15 March 2022.
- *MDAG Issues discussion paper: Price discovery under 100% renewable*, NZIER report

to MEUG to support submission to the Market Development Advisory Group, 10 March 2022.

121. All MEUG's submissions are available on our website here: www.meug.co.nz

122. All iterations of the Ireland, Wallace & Associates (IWA) Economic Profit Analysis (EPA) work on Meridian Energy and Contact Energy are also published on our website, with links below.

Meridian Energy	• http://www.meug.co.nz/node/1280 • http://www.meug.co.nz/node/1244 • http://www.meug.co.nz/node/1175 • http://www.meug.co.nz/node/1159 • http://www.meug.co.nz/node/1157 • http://www.meug.co.nz/node/1151 • http://www.meug.co.nz/node/1150
Contact Energy	• http://www.meug.co.nz/node/1282 • http://www.meug.co.nz/node/1282 • http://www.meug.co.nz/node/1184 • http://www.meug.co.nz/node/1182

Appendix B: NZIER report

Energy Strategy – electricity markets

MBIE Electricity market transition measures

NZIER report to Major Electricity Users Group (MEUG)

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Key points

Overall, the approach in the MBIE paper Measures for Transition to an Expanded and Highly Renewable Electricity System' (EMM) is more descriptive and less quantitative than the analysis already completed by MBIE for the NZ Battery Indicative Business Case (IBC), or the analysis completed by the Electricity Authority (EA) and its Market Development Advisory Group (MDAG). The analysis is also vague about the time for the transition from thermal to renewable generation. Therefore the key messages from NZIER are:

- To use the analysis from the NZ Battery IBC and the EA and MDAG work as a foundation for the definition and quantification of issues such as wholesale price volatility, generation capacity required to meet peak demand, likelihood of renewable generation spill and challenges for the measurement of market power.
- The MDAG and NZ Battery IBC present point forecasts for 'now' and 2030 or 2035 when the transition to 100 percent renewables is assumed to be complete. For the development of a strategy, these forecasts need to be supplemented by more detailed modelling and analysis of what could happen during the immediate transition period (2023 to 2030).
- The need to address conflicting objectives (for example 100 percent renewable generation by 2035 versus maintaining firming capacity during the 'transition) and gaps in the strategy (lack of description of the outlook for system supply, demand, prices, and reliability).
- Clearly specify the timeframe considered by the strategy and then separate it into periods that reflect the shorter of major changes in demand/supply conditions or five years and linked to changes require3d under the greenhouse gas emission reduction plans.

The key challenges for the electricity system in the replacement of the existing natural gas fuelled thermal generation with wind and solar generation alongside the increased demand for electricity from economic growth and the electrification of passenger vehicles and process heat are:

- The intermittency of wind and solar generation is much harder to predict and will on a larger scale than the fluctuations in capacity of the existing generating plant. This will make the system's generating capacity less predictable and increase the risk of a mismatch between demand and supply
- The existing coal and natural gas fuelled capacity which has been used to 'firm' (cover shortfalls in the reliability of renewable generation) in the past will be less capable of performing this task. It will also be more expensive to run over the assumed phase-out period due to reduced capacity, increased fuel and emissions costs and the increased requirement for firming capacity as demand grows. As an example of the cost pressures an increase in the NZU price from the current quarterly average of about \$60 per tCO_2e to \$160 per tCO_2e (the level projected by the Climate Change Commission for 2035) would increase the fuel cost of:
  - gas generation at Huntly Unit 5 by \$42 per MWh to about \$145 per MWh

- coal generation at Huntly Units1, 2 and 4 by $105 per MWh to $194 per MWh.

  This pure cost increase attributable to the rise in NZU prices is much lower than the modelled increase in wholesale prices at peak periods which will be necessary to clear markets in 2035 operating without natural gas fuelled peakers, as indicated by the MDAG modelling price duration curves for 2035 and 2050 compared to simulated recent history[1].

- New thermal plant considered in the NZ Battery and MDAG forecasts will be much more expensive to run and make much smaller contributions to generation capacity and reliability than the existing thermal capacity. This implies a much larger task for battery storage and demand response, but there is very little discussion about how this capacity could be developed let alone made sufficiently responsive to match the much wider range of fluctuations in solar and wind output.
- Both the MDAG modelling, and NZ Battery IBC indicate average wholesale electricity prices in 2035 will be $77 per MWh in 2035 - lower than the historical average over 2000 to 2020 of $86 per MWh[2] and will be $88 per MWh in 2050 (without the dry-year risk options considered in the NZ Battery IBC. The MDAG modelling notes that prices will be more volatile, price duration curves will be much steeper and the level of spill from hydro, wind and solar generation will be much higher than 'now'.
- The projections of average wholesale prices are the product of countervailing forces. The falls in the per MWh costs of wind and solar generation and battery storage and the willingness of owners of these assets to accept very low prices in off-peak periods rather than 'spill' generation capacity will exert downward pressure on wholesale prices. The shortage and high cost of firming capacity and the high cost of demand response will put upward pressure on wholesale prices. The net effect of these forces will depend on the competition between generators.
- Based on the EA analysis of price movements over 2018 to 2021 (following the Pohokura gas outage), the current level of competition between generators delivered an increase in average wholesale prices of $38 per MWh that could not be explained by changes in fuel costs. However, the EA could not unequivocally attribute this to the exercise of market power.
- The MDAG modelling projects that the transition to 100 percent renewables will concentrate control of and reduce competition in the provision of peak generation capacity and that the capacity will fall from 4,984 MW to 3,563 MW – a fall of 26 percent by 2035[3]
- The NZ Battery IBC did not have a new strategy for modifying generation capacity to deal with dry-year risk before the early 2030's. In the absence of this strategy, the system is reliant on the existing capacity. The phase-down in coal and natural gas-fuelled thermal capacity required by the strategy objective of 100 percent renewables by 2030 implies the system's capacity will be reduced by 2030. Consideration of how

1 'Price Discovery with 100% Renewable Electricity Supply, Final, Prepared for MDAG, 10 December 2021' page 20

2 'Price Discovery with 100% Renewable Electricity Supply, Final, Prepared for MDAG ,10 December 2021' page 18

3 '100% renewable electricity supply – competition issues, Material for MDAG meeting, 24 August 2022'. Page 13 predicts that the share of ownership flexible hydro and thermal capacity will change from three with roughly equal shares 'now' (Genesis 30%, Meridian 28%, Contact 24% followed by Mercury with 14%) to one dominant supplier (Meridian 40% followed by Contact 19%, Mercury 19% and Genesis 17%). The balance of 4% 'now' and 5% in 20235 is owned by other generators.

to manage dry year risk over the transition period should be added as specific question for the strategy discussion.

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1 Scope

Purpose

This note suggests key messages for the Ministry of Business, Innovation and Employment (MBIE) consultation paper 'Measures for Transition to an Expanded and Highly Renewable Electricity System'[4] referred to in this note as Electricity Market Measures (EMM) consultation paper.

2 Strategy introduction

2.1 Introduction

This should define the problem that the strategy is intended to address. Instead it provides a very broad overview of the range of demand forecasts and considers key dates of 2030 and 2050. Table 1 below summarises the main points in chapter 1

[4] In addition to this paper MBIE has also published the following consultation documents on 9 August 2023: 'Advancing New Zealand's energy transition (an overview paper), 'Gas Transition Plan issues paper', 'Interim Hydrogen Roadmap', 'Developing a regulatory framework for offshore renewable energy', and 'Implementing a ban on new fossil-fuel baseload electricity generation'. (The Interim Hydrogen Roadmap was supported by 'Hydrogen Economic Modelling Results' This report provides much more quantitative detail on the outlook for demand for natural gas than the gas transition plan) The consultation papers all available from https://www.mbie.govt.nz/have-your-say/consultation-on-advancing-new-zealands-energy-transition/ . The ''Hydrogen Economic Modelling Results' is available from' https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-strategies-for-new-zealand/hydrogen-in-new-zealand/roadmap-for-hydrogen-in-new-zealand/ . See **Error! Reference source not found.**

Table 1 Introduction

Transitioning to a renewable energy that is affordable and reliable

Strategy	Comment
Objectives: • net zero emissions of long-lived greenhouse gases by 2050 and three emissions budgets • 50 per cent of total final energy consumption to come from renewable sources by 2035 • aspirational target for 100 per cent renewable electricity by 2030.[1]	Need to focus on issues over the next 5 to 10 years. Focus on trilemma – supporting economic development/ productivity is inferred. Aspirational target of 100 percent renewable by 2030 does not fit with modelling scenarios and is expensive to achieve. Leaving the system without fast response peaker plant is a material change to volatility and price risk. (Para 26 refers to significant progress.) Check MDAG forecasts for assessment of reliability.
Electricity demand could grow by 18 to 78 percent between 2018 and 2050 across five different scenarios (MBIE 2019 forecasts). Transpower estimates 43 TWh in 2020 to 70 TWh by 2050 - 14 per cent increase in base electricity demand, a 38 per cent increase in electricity demand from vehicle electrification and a 16 per cent increase in demand from electrification of process heat and industry.[2]	Massive variation in the range of forecast demand and therefore the exposure of the system to intermittent generation. The forecasts need to be translated into effect on ability to meet peaks and dry year risk and the impact on wholesale prices. EV and process heat are structural changes with different drivers from the growth in base demand. Transpower's forecast of 70 TWh of demand by 2050 is in line with but about 5 TWh higher than the forecast by both MDAG and the forecast for the NZ Battey business case.
Other policy initiatives: include accompanying consultation papers, IM and wholesale market review, and EV charging requirements, GIDI and emissions reduction plan.	List of initiatives is a mix of routine regulator work and peripheral decarbonisation policies. No clear direct effect on generation investment or management of volatility.
NZ energy only market and ETS	Connection between the ETS and energy only market refers to effect of ETS on thermal SRMC – superficial.
Notes: 1 Paragraph 2 page 11 2 Paragraph 11 pages 11 to 12	

Source: NZIER

2.1.1 Scenario issues

The situation and issues being considered in the EMM consultation paper can be usefully separated into the following phases:

- Replacement of slow start coal and natural gas fuelled thermal with renewables over 2025 to 2030.
- Replacement of natural gas fuelled peakers with biofuel peakers over 2030 to 2037
- Post NZ Battery 2038 to 2050.

During the first two phases covering the period 2025 to 2037, the market must manage dry-year risk using available thermal capacity and over-build of renewables. The key drivers of market conditions over this period are:

- Retirement of coal and natural gas fuelled thermal plant and the availability of unretired plant (due to factors such as fuel supply, equipment availability)
- Speed at which new renewable capacity is constructed and management of spilled capacity.

The forecasts prepared for the Electricity Authority (EA) by its Market Development Advisory Group (MDAG) and by MBIE in the development of the NZ Battery IBC tend to provide average point estimates for 'milestone' years (such as 2035 or 2050). The forecasts do not provide detailed analysis of conditions in the intervening transition years, the potential range of output and capacity required from back-up generation, storage or demand response or estimates of the likelihood that the forecast range of capacity and output will be sufficient to match demand and supply for electricity.

2.1.2 MDAG and NZ Battery forecasts

To narrow the range of forecast generation

Table 2 Demand forecasts excluding NZAS

Gross demand component in TWh

Source	2020 100% Renew	2020 Business case	2035 100% Renew	2035 Business case	2050 100% Renew	2050 Business case	2065 Business case
Base[1]	37.3	37.3	40.0	40.0	45.2	45.1	49.3
EV load	0.0	0.0	5.3	5.2	12.4	12.4	14.2
Dairy process heat[2]	0.0	0.0	1.8	1.8	2.8	2.8	2.3
Other process heat	0.0	0.0	2.4	2.4	5.2	5.2	6.2
Total	**37.3**	**37.3**	**49.5**	**49.4**	**65.6**	**65.5**	**72.0**

Note:

1 The 'Base' demand for the business cannot be read from the chart for 2020, 2035 and 2050 but is calculated as the residual of total demand less the other components.

2 The value for 'Dairy process heat' is not included as a label on either chart. In this table 'Dairy process heat' is calculated as 'Total' less the other demand components for 100% Renew.

Source: NZIER

We treat the generation capacity, output and spill forecasts from 100% Renew as an initial estimate of the forecasts used in the business case.

Table 3 Core generation capacity and output forecasts excluding NZAS

Capacity in GW and gross output In TWh

	Capacity (GW)				Output (TWh)		
Type -fuel	2020	2035	2050	Type -fuel	2020	2035	2050
Thermal	0.3	0	0	Thermal	0.3	0	0
Cogen	0.3	0	0	Cogen	1.2	0	0
HydroRR	0.6	0.6	0.6	HydroRR	2.2	2.2	2.1
Hydro	4.5	4.5	4.5	Hydro	19.8	19.2	18.7
Geo	1.3	1.4	1.8	Geo	10	11	13.8
Wind	1.3	3.5	6.2	Wind	4.4	11.7	20.1
Solar	0	1.7	4	Solar	0	3	6.7
Rooftop PV	0.4	1.3	2.4	Rooftop PV	0.4	1.6	2.9
Peaker (Green)	0.6	0.7	0.9	Peaker (Green)	0.1	0.1	0.2
Total capacity	**9.3**	**13.7**	**20.4**	**Total Generation**	**38.4**	**48.8**	**64.5**
				Total Demand	**35**	**48.5**	**64**

Source: 'Price Discovery with 100% Renewable Electricity Supply Final', page 85

3 PART 1: GROWING RENEWABLE GENERATION

3.1 Overview of Part 1

Part 1 of the EMM consultation paper refers to the pace of growth in renewable generation but is primarily concerned with responding to the retirement of thermal generation and the resulting mismatch between peak demand and the lower reliability of intermittent generation. The recent experience of the construction of onshore wind and the projections of wind and solar farm construction in the Concept Consulting report suggest the level and capacity of wind and solar generation will meet forecast requirements over the next 5 to 10 years. There does not seem to be a market failure that requires government intervention.

Table 4 Growing renewable generation

Mismatch between thermal retirement assumptions and growth in renewable generation

Strategy	Comment
Challenges	
Sufficient new renewable generation to replace retiring thermal and meet increasing demand	Need to discuss the estimates of demand and supply to quantify the gap. Also some recent wind farm development built less capacity than consented.
Sufficient firming capacity	No commercial alternative to natural gas has been identified at least before 2035. Direct clash with 100% renewable goal
Manage pace of fossil fuel retirement	Base and peak load thermal are separate issues. (Effectively natural gas-fired given total coal cost.) Thermal generation owners have strong incentives to develop replacement generation capacity to preserve other business lines.
Work underway	
MDAG price discovery	Should be used in the analysis. Particularly estimates of price duration curves and effect of 'hedging' on wind and solar revenue volatility.
EA: 'Ensuring orderly thermal transition' and promoting competition in the wholesale market	Thermal transition does not consider outages. Promoting competition analysis does not consider effect of loss of competition to supply at peak periods on peak wholesale prices or shoulder prices.
Further possible measures	
New generation to run in peak demand periods, at short notice	Problem is identifying acceptable generation with these characteristics and then assessing impact on wholesale prices.
New renewable generation (that runs most of the time)	Not clear what this means or achieves.
New fossil gas fired generation that can generate at short notice if needed in the short-term during transition	The economics for this would be challenging. Need to explain how this fits with aspirational 100% renewable and 'Hydrogen Economic Modelling Results' for natural gas supply. EA assumes new investment unlikely before 2032.
Manage phasedown of existing fossil fuel generation for security of supply	Phase down is driven by commercial imperative, plant availability and for Huntly Rankine units cost of biofuel (torrefied[5] wood pellets).

Source: NZIER

3.2 Accelerating supply of renewables (chapter 2)

The gap between the expected supply of renewables and the expected growth in demand is not clearly defined. The discussion is stuck at an aggregated level:

- There could be a risk that renewable capacity will not be high enough to generate enough GWh to meet a poorly defined demand growth and vaguely defined retirement of thermal capacity

[5] Torrefaction involves heating wood chips in a high-pressure oxygen-free chamber to extract moisture and collapse the wood cell structure. The pellets produced from this process have higher energy density than wood pellets, and do not absorb water when stored outside.

- The alleged slow pace of investment is implicitly attributed to investor uncertainty about revenue due to wholesale price volatility

The EA and MDAG work provides an evidence base for considering these issues. Other factors such as the NZ Battery decision, uncertainty about EV take-up and process heat electrification and the steady improvement in efficiency of wind and solar generation are also likely to be factors affecting the time of investment in new renewable generation.

Interventions to accelerate investment in generation (like CfD) need to be based on a clear definition of market failure and have their costs and benefits analysed especially where they supplant existing market arrangements (PPA) or favour one form of generation over another. The examples of CfD provided in the strategy paper also need to consider how to avoid paying for any capacity that will be spilled (either directly by the generator operating under the CfD or if the spill is displace to other generators not operating under a CfD).

Table 5 Accelerating supply of renewables Questions 1 to 3

[insert caption subheading]

Question	Answer
1. Are any extra measures needed to support new renewable generation during the transition? Please keep in mind existing investment incentives through the energy-only market and the ETS, and also available risk management products. Any new measures should add to (and not undermine or distort) investment that could occur without the measures.	No. The planned investment in renewable generation is responding to demand and appears to be in line with the expectations for transition away from thermal capacity. The declining costs of wind and solar generation combined with the rising cost of coal and gas, as well as supply risks for both coal and gas are encouraging the development of new wind and solar capacity. The factors delaying investment in new wind and solar generation are likely to included resource consent application processes, availability of equipment and construction staff and the prospect of future efficiency gains.
2. If you think extra measures are needed to support renewable generation, which ones should the government prioritise developing and where and when should they be used? What are the issues and risks that should be considered in relation to such measures?	If any extra measures are chosen, they should focus on addressing causes of construction delays. Of the measures listed in the consultation paper CfD and PPA offered through tenders are likely to be the least distorting foe the NZ market. However the examples of overseas practice provided are not directly relevant to the New Zealand market. The CfD examples taken from the UK apply to a market where most of the generation is thermal. PPAs are already in use in New Zealand.
3. If you don't think further measures are needed now to support new renewable generation, are there any situations which might change your mind? When and why might this be?	A potential application of the measures discussed in the consultation paper is the application of the New South Wales approach to securing renewable capacity that is more suited to firming.

Source: NZIER

3.3 Ensuring sufficient firm capacity during transition Chapter 3

The transition period for the phase-out of natural gas use is poorly defined. The characteristics of the generation or storage capacity that could replace the thermal capacity are not described at all and neither is the effect of the phase out of natural gas generation on the management of excess peak demand discussed. If the issue of firming capacity is not resolved, then the system has to rely more heavily on demand curtailment to manage unexpected dips in supply which is likely to shift the risk of high spot prices to industrial users with 24-hour demand.

Table 6 Firming capacity during transition

MDAG and EA analysis forecast a decline in thermal capacity over the strategy period

Strategy	Comment
Challenges	
Maintaining security of supply and affordability.	Security of supply will be eroded due to reduced reliability of generation. Effect on affordability will depend on valuation of secure supply and allocation of cost to meet security expectations.
Avoid challenges for intermittent renewables investors to find buyers for their output.	With the level of increased demand forecast for EV and process heat electrification -selling the output is not the problem. Limiting the price for supply at peak periods (if continuous supply is required) is the issue.)
Work underway	
Recent modelling by MDAG and BCG and earlier Climate Change Commission Modelling	The MDAG works estimates the wholesale price volatility caused by increased reliance on renewables. The BCG and Climate Change Commission modelling only consider the high-level requirement for thermal generation but provided little detail on the modelling assumptions.
Analysis of battery electric storage systems	Previous modelling suggests limited role for batteries. Need a clearer explanation of how this technology complements reliable generation.
Further possible measures	
Mechanisms from Ch2	Building firming capacity is harder than the issues the Ch2 interventions are designed for.
Capacity markets	Rejected by MDAG. Do not solve core problem of physical lack of reliable controllable generation capacity.
Retailer reliability obligation	More likely to shift risk to another consumer group than improve the reliability of generation. Useful to discover customer valuation of reliability.
Govt investment in peaking plant	Need to also have secure supply of natural gas.

Source: NZIER

3.3.1 ENSURING SUFFICIENT INVESTMENT IN PEAKING AND FIRMING CAPACITY

The consultation paper needs to consider the options for extending the life of existing thermal plant and the range of fuel costs for the plant. This needs to be discussed outside the assumption in the consultation paper of 100 percent renewable electricity by 2030 or the assumption in the reference cases for both the MDAG and the NZ Battery business case that the natural gas fuelled thermal generation will cease by 2035. (The NZ Battery IBC notes that coal may still be a potential thermal generation fuel beyond 2035[6].) The key issues that need to be included in the discussion are the volume of fuel available and the price per GJ compared to other generation options.

6 '…it is not guaranteed that the market would – with no incentives other than carbon prices – close off coal as an option.' NZ Battery Indicative Business Case, 6.6.2 Fossil fuel peakers', page 286.

The problem of ensuring sufficient investment in peaking and firming capacity is complex and the interdependencies vary over time. While the discussion in this paper is focused on the economics of thermal generation in the electricity sector it assumes that a suitable thermal generation fuel will be available. However, none of the recent analysis has identified a commercially viable alternative thermal fuel to natural gas for slow-start[7] let alone fast-start (peaker) thermal generation. The estimated price of the fuels is very high compared to the natural gas price even with the price of emissions. This means that the reliability and price of future gas supplies are a necessary condition for the discussion of the adequacy of future peaking and firming capacity and the likelihood of investment in new capacity. The reliability and price of future gas for electricity generation are primarily driven by demand for gas by the production of methanol, fertiliser and industrial process heat. The Gas Transition Plan consultation plans does not quantify scenarios for the phase out of natural gas – aside from restating the Climate Change Commission reference case. The most detailed quantification of the potential reduction in the use of natural gas is presented in the modelling that supports the Interim Hydrogen Roadmap[8].

In the 'transition phase' for existing thermal generation (up to 2032) none of the major forecasts include the development on any new thermal capacity The available scenarios for the transition to renewables do not assume the continuation natural gas fuelled thermal generation beyond 2035 and do assume the commissioning of bio fuelled peakers from 2030 to 2035 but are not explicit about the fuel that could be used or its costs:

- NZ Battery assumes retirement of thermal capacity ahead of the commissioning of new peaker capacity:
  - New biofueled peaker capacity of 2,060 MW by 2035- 360 MW in 2030 and 1,700 MW in 2035. This capacity has a forecast[9] variable operating and maintenance costs for $480 per MWh and annualised fixed costs $100,000 per MW. The NZ Battery IBC estimates a range of green peaker generation in 2035: 50.0 GWh[10], 92.8 GWh[11] or 1,965.8 GWh[12]. This range of output implies a wide variation in the recovery of fixed annualised costs.
  - Retirement of
    - 1,109 MW by 2025: Huntly Rankine (729 MW) and Taranaki combined cycle (380 MW) units in 2025

7 The Genesis trial of biomass fuel to generate 1.5 GWh of electricity reported emissions of 895 tonnes CO_2, '*51% less emissions than would have been produced from burning coal.'* See 'GENESIS ENERGY LIMITED INTEGRATED REPORT 2023, Our biomass trial', page 24, available at https://media.genesisenergy.co.nz/genesis/investor/2023/genesis_fy23_integrated_report.pdf?_ga=2.10641204.1475539279.1697664155-414064390.1695866795&_gac=1.241910326.1697664155.EAIaIQobChMIkPmP5MOAggMVABCDAx3l3wsFEAAYASAAEgLPBvD_BwE . We interpret the Genesis statement as emissions form torrefied wood pellets being 49 percent of emissions from coal. We understand that the CO_2 emissions factor for natural gas 58.38 percent of the emission factor for coal which implies that the CO_2 emissions factor for torrefied wood pellets is a about 84 percent of the CO_2 emissions factor for natural gas. We have not been able to confirm the cost of the biofuel used for the trial. However, literature reviews and recent website searches suggest a factory gate costs of USD 8 to USD 10 per GJ which at the current exchange rate would be about NZD 13.70 to NZD 18.00 per GJ plus transport costs.

8 Hydrogen Economic Modelling Results, Final Report, 03 August 2023, Ernst Young

9 NZ Battery Indicative Business Case, Table 39: Green peaker CAPEX assumptions and Table 40: Green peaker OPEX assumptions, pages 285 to 286. The recovery of fixed annualised costs does not make a material difference to the cost of electricity per MWh and the estimated number of hours that operate per year is 24.3.

10 NZ Battery Indicative Business Case, Option 1: Counterfactual 'Green peaker fuel use' page 332 and 'Supply chain:' page 325

11 NZ Battery Indicative Business Case, Option 2: Counterfactual 'Green peaker fuel use' page 324 and 'Supply chain:' page 325

12 NZ Battery Indicative Business Case, Option 3: Counterfactual 'Green peaker fuel use' page 324 and 'Supply chain:' page 325

- 265 MW by 2033: Whirinaki (155 MW) in 2029 and McKee (100 MW) and Edgecumbe (10MW) in 2033
- 752 MW by 2035: Huntly E3p (403 MW), Huntly P40 (40 MW), Stratford Gas Turbine (200 MW), Junction Road (100 MW) and Bream Bay Peaker (9
- MW).

- MDAG forecasts assume retirement of the existing thermal capacity by 2035 with the construction of biofueled peakers (700 MW) by 2035 and a further 200 (MW) by 2050.

Table 7 Ensuring sufficient firming and peaking capacity (Questions 4 to 7)

MDAG and EA (Concept Consulting) modelling suggest retirement of new thermal capacity over 2025 to 2032

Question	Answer
4. Do you think measures could be needed to support new firming/dispatchable capacity (resources reliably available when called on to generate)? If yes, which kind of measures? What needs do you think those measures could meet and why?	No. The question needs to be prefaced by an assessment of the firming and peak capacity shortfall and a list of new firming capacity and dispatchable resources and the circumstances under which the commissioning could be accelerated. The MDAG and NZ Battery scenarios provide an estimate of average wholesale prices and price volatility in 2036 on the assumption that there is no natural gas fuelled thermal generation.
5. Are any measures needed to support storage (such as battery energy storage systems or BESS) during the transition? If yes, what types of measures do you think should be considered and why?	No. The consideration of measures to support storage needs to be preceded by an analysis of what role battery storage can perform in supplementing the reliability of renewable generation. The NZ Battery IBC made an initial assessment of the potential role of battery storage compared to the other storage options but this was focused on dry year risk..
6. If you answered yes to question 4 or 5 above, should the support be limited to renewable generation and renewable storage technologies only or made available across a range of other technologies? Keep in mind that fossil fuels are generally the cheapest option for firming, though this may change over time as renewable options (particularly batteries) become more efficient and affordable.	The development of any ‘support’ measures needs to be based on a clear problem definition and a cost benefit analysis that demonstrates that the ‘insurance’ provided by the measure against unmet demand ins effective and efficient. The uncertainty about the intermittency of renewable energy supply and the timing of the retirement of natural gas fuelled thermal generation makes it very difficult to complete an accurate cost benefit analysis. To limit the potential for market distortion, the measure should not be restricted to ‘renewable’ generation technologies. The uncertain outlook for gas supplies is likely to discourage investment in new natural gas fuelled gas generation. However biofuels which are ‘renewable’ but have high emissions should not be excluded.
7. If you answered yes to question 6 above, what are the issues and risks with this approach? How could these risks and issues be addressed?	The main risk with measures to support renewable generation is that it creates a less efficient (allocative and dynamic) solution to generation uncertainty than would be delivered by the market

Source: NZIER

3.3.2 Investment in natural gas peaking plant during the transition

Table 8 Natural gas peaking plant during the transition Questions 8 to 11

EA (Concept Consulting) modelling suggests build of new thermal peaking capacity over 2025 to 2032 is unlikely

Question	Answer
8. Are any measure(s) needed to support existing or new fossil gas fired peaking generation, so as to help keep consumer prices affordable and support new renewable investment?	The primary measures that are required are the removal of the uncertainty about the use of gas for electricity generation from the aspirational objective of 100 percent renewable generation within a set time and the uncertainty in the gas transition plan.
9. If you answered yes to question 8 above, what measures should be considered and why? What are the possible risks and issues with these measures?	See above answer. Assuming the availability of gas for electricity generation can be confirmed for a set period, the form of measure is likely to be some form of capacity market. MDAG has advised against these measures to firm wind and solar generation because they are not fit for purpose.
10. If you answered yes to question 8 above, what rules would be needed so that fossil gas generation remains in the electricity market only as long as needed for the transition, as part of phase down of fossil gas?	The duration and shape of the transition period is ill-defined and is affected by the cost and reliability of alternatives such as renewable storage and demand response. This makes it very difficult to design effective rules to discourage use of natural gas outside the transition period. The two main factors affecting the use of natural gas during the ill-defined transition period are the reliability of supply and the price of natural gas including the cost of NZU to cover emissions. These factors will be largely determined by drivers outside the electricity market.
11. Are there any issues or potential issues relating to gas supply availability during electricity system transition that you would like to comment on?	The gas transition plan and its effect on the outlook for gas demand from methanol and fertiliser production are the main factors that influence the continuation of a reliable and affordable supply of natural gas for electricity generation.

Source: NZIER

3.4 Managing slow-start thermal capacity during the transition Chapter 4

The transition period for the phase-out of slow-start coal and natural gas generation is poorly defined. Genesis has already signalled that it intends to fully phase out coal use for electricity generation by 2030[13]. However the outlook for natural gas fuelled generation is less clear.

13 Genesis intends to stop using coal for electricity generation from 2025 under normal hydrological conditions.

Table 9 Natural gas peaking plant during the transition Questions 12 to 14

EA (Concept Consulting) modelling suggests existing thermal peaking capacity over 2025 to 2032 will be commercially viable

Question	Answer
12. Do you agree that specific measures could be needed to support the managed phasedown of existing fossil fuel plants, for security of supply during the transition?	No, the evidence for this is mixed. Genesis owns the bulk of slow start-thermal capacity that is not due for retirement. This capacity is required by Genesis to supply a substantial part of its retail customer base, as well as providing competition for hydro generation at peak periods. Genesis is also trialling torrefied wood pellets as a replacement fuel for coal.
13. If you answered yes to question 12 above, what measures do you think could be appropriate and why? What conditions do think you should be placed on plant operation? For example, do you have any views on whether there should be a minimum notice period for reductions in plant capacity, and/or for placing older fossil fuel plant in a strategic reserve?	Assuming the availability of gas for electricity generation can be confirmed for a set period, the proposed measures are likely to be some form of capacity market. MDAG has advised against using capacity markets to firm wind and solar generation because they are not fit for purpose. A minimum notice period for shutdown does not guarantee the level of output that will be provided by the operator or the price at which the output will be offered during the notice period.
14. If you answered yes to question 12 above, what are the issues and risks with these measures and how do you think these could be addressed?	The main issue with the measures such as minimum notice period or placing them in a strategic reserve are that they reduce the flexibility with which these resources can be deployed in the market and impose a cost on the market for a collective insurance policy that may not be efficient.

Source: NZIER

3.5 Role of large-scale flexibility chapter 5

The focus of this chapter is on how large-scale industrial users could manager their exposure to peak electricity prices. The comments overlook two issues:

- Established industrial users have faced a structural increase in average wholesale prices since about 2018 due to shortage of thermal capacity forcing which meant that prices were set based on scarce hydro resources.
- The benefit of avoiding short term unpredictable price spikes is much lower than the cost of lost production and restarting production processes.

The objective of the measures is to avoid the cost of constructing high-cost generation by encouraging industrial users to reduce their demand in response to intermittent reduction in supply from wind and solar generation. The paper does not provide any information to compare the demand and supply profiles.

Table 10 Role of large-scale flexibility Questions 15 to 17

The task (speed, capacity and duration) that large scale flexibility needs to perform is ill-defined

Question	Answer
15. What types of commercial arrangements for demand response are you aware of that are working well to support industrial demand response?	There are a small number of bi-lateral arrangements for NZAS and NZ Steel to shed load and Solar Zero is participating in the EA dispatchable demand initiative. These examples make a small contribution to reducing industrial load. (The dispatchable demand model is not attractive to large industrial users because it does not provide a material benefit.)
16. What new measures could be developed to encourage large industrial users, distributors and/or retailers to support large-scale flexibility?	New measures are difficult to develop for large users because at most the benefit offered is based on the avoidance of high wholesale spot prices for the period of the demand reduction. This is much lower than the cost to large users of the disruption caused by the need to stop and restart production processes. The pricing tranches assumed by MDAG and the NZ Battery IBC for demand response are too low to reflect the costs to large users of participating.
17. Do you have any views on additional mechanisms that could be developed to provide more information and certainty to industry participants?	The recent EA analysis of the change in peak demand after the change in transmission cost allocation from regional coincident peak demand (RCPD) to the new transmission pricing methodology provides an example of the benefit required to encourage load shifting over a small number of periods that could be predicted well in advance based on historical patterns. The demand response required to address shortfalls from wind and solar generation is much more frequent and occurs at much shorter notice than the demand response required to reduce load during RCPD. Also the benefit is limited to avoidance of higher wholesale electricity prices. It is difficult for participants that reduce load to measure this gain and it is shared by all load customers.

Source: NZIER

4 PART 2: COMPETITIVE MARKETS

The MBIE paper reports that the phase-out of thermal generation might weaken competition in some parts of the market *‘particularly for firm resources that can balance non-firm resources over periods longer than a few days.’*

The comment in the MBIE paper is an understatement of the risk of increased wholesale prices as system reliance on hydro resources to ‘firm’ intermittent wind power increases and is based on comments by the EA and MDAG. The EA analysis barely acknowledges the existence of an issue. The MDAG papers provide an initial simulation of the potential effect of the 100 percent renewable generation on the shape of wholesale prices but do not comment on the mismatch between their projections and recent market experience.

Table 11 Competitive markets

Strategy	Comment
Challenges	
Market concentration of providers of dispatchable generation or other flexible resources could increase as the use of fossil fuel generation reduces	This will occur, but the wholesale price impacts are uncertain. The experience from the gas outage in2018 was that wholesale prices were 'reset' with higher prices in both peak and off-peak periods that were sustained after the gas outage was resolved.
Resulting reduction in competition could adversely affect electricity prices and reliability during and after the transition	This will also occur. The MDAG analysis provides a simulation of the change in shape of price duration curves but suggests a fall in average electricity prices. The forecast fall is not consistent with recent experience.
Work underway	
EA work to improve wholesale price discovery and competitive access to flexible services	EA solutions address second order issues but are not focused on the market power of hydro generators in setting prices during peak or shoulder periods. They are: • Not focussed on comparing EA models of water values with hydro generator models • Not suitable for assessing the impacts of the much higher levels of spill that will occur in a 100 percent renewable system.
EA market monitoring	A key part of the current monitoring is the SRMC of thermal generators which has become less important since 2018 and will become irrelevant during the transition.
MDAG recommendations to improve competition	MDAG recommendations are essentially close monitoring and do not address the issues of shortage of reliable peak capacity and the need for much higher levels of spill under 100 percent renewables.
Further possible measures	
Range of specific conduct or structural measures including:	There is a low appetite and long lead times for structural change measures. Analysis of hydro generator approaches to setting wholesale prices during peak periods and the stickiness of high prices for shoulder and off-peak periods would be a useful intermediate step. This would include analysis of how hydro generators 'value' water compared to the models used by the EA.
Horizontal separation of generators with significant market share in flexible hydro storage,	Success of this measure relies on the ability to separate the physical operation of parts of hydro systems so that they can be run as competitors.
Vertical separation of gentailers controlling hydro storage	
Regulated access pricing for flexibility services/contracts provided by generators that control flexible resources, and/or central procurement of new and existing flexible resources	Central procurement carries high risks of inefficient outcomes and unintended consequences.

Source: NZIER

4.1 Workably competitive electricity markets chapter 6

Table 12 Workably competitive markets issues Questions 18 to 20

MDAG analysis suggests that the transition to renewables will concentrate ownership of flexible hydro and thermal generation

Question	Answer
18. Do you agree that the key competition issue in the electricity market is the prospect of increased market concentration in flexible generation, as the role of fossil fuel generation reduces over time?	Yes. The shift to reliance on hydro generation to meet peak demand means that generators with this capacity effectively set the price for generation during these periods. In these situations the 'price of fuel' is set by the generators based on their expectation of future water values. These values can vary widely depending on demand and hydrological forecasts and there is no independent objective way to test these values. Accordingly, it is very difficult to distinguish the exercise of market power from the price outcomes that would be delivered by workably competitive markets as has been demonstrated by the recent EA review of competition in wholesale markets. Further, wholesale prices set in periods of constrained generation can be sticky as was demonstrated in the aftermath of the 2018 Pohukura gas outage where the EA regression equation of price drivers included a dummy variable to explain some of the step change in wholesale prices that occurred after the outage.
19. Aside from increased market concentration of flexible generation, what other competition issues should be considered and why?	In addition to the concentration of flexible capacity with one to two generators the market will also have much higher levels of spill of hydro, wind and solar generation. This will make it much harder to identify when prices in the off-peak periods are being lifted by spill.
20. What extra measures should or could be used to know whether the wholesale electricity market reflects workable competition, and if necessary, to identify solutions?	The MDAG report has suggested a range of measures that are helpful to improve the amount of information available to the market, but its final recommendations will not be completed until the end of this report. Ultimately a necessary but not sufficient condition for the market to deliver more competitive wholesale prices is access to scalable thermal generation with a fuel cost that can be measured independently and is competitive with peak hydro resources.

Source: NZIER

Table 13 Measures to address competition issues Questions 21 to 25

Question	Answer
21. Should structural changes be looked at now to address competition issues, in case they are needed with urgency if conduct measures prove inadequate?	Both MDAG and EA analysis have suggested that structural separation will be difficult to achieve and is unlikely to deliver benefits. While the option should be discussed, the discussion needs to build on the analysis already done. Structural separation will not address the root cause of the problem which is lack of reliable peaker capacity.
22. Is there a case for either vertical separation measures (generation from retail) or horizontal market separation measures (amending the geographic footprint of any gentailer) and, if so, what is this?	See answer to question 21.
23. Are measures needed to improve liquidity in contract markets and/or to limit generator market power being used in retail markets? If yes, what measures do you have in mind, and what would be the costs and benefits?	Yes, the MDAG recommendations are a good starting point for this.
24. Should an access pricing regime be looked at more closely to improve retail competition (beyond the flexibility access code proposed by the Market Development Advisory Group or MDAG)?	Yes, this worth further discussion, but the capacity problems in the telecommunications market are different to those in the electricity market.
25. What extra measures around electricity market competition, if any, do you think the government should explore or develop?	The work already done by MDAG and the NZ Battery IBC on assessing the incidence of wholesale price volatility and the increased likelihood that generation cannot always meet demand as the proportion of renewables needs to be explicitly included in the strategy discussion and used as a starting point for the feasibility of demand response by retail consumers.

Source: NZIER

Table 14 Single buyer model Question 26

Question	Answer
26. Do you think a single buyer model for the wholesale electricity market should be looked at further? If so, why? If not, why not?	No. A single buyer model does not resolve the key challenges facing the system of lower predictability of generation capacity, concentration of market power with hydro generators and exposure to dry- year risk at least until 2038 (under the current schedule for the NZ Battery Indicative Business Case).

Source: NZIER

Appendix A Thermal generation cost

A.1 Cost factors for existing thermal generation

The cost of thermal generation is a hybrid of different costs depending on the:

- type of plant slow start/baseload (like the Huntly and Taranaki Combined Cycle) plants or peaker plant
- the type of fuel: coal which has double the emissions of natural gas and is being phased out, natural gas which is used by most of the thermal plants but has price and supply uncertainty and diesel which is the most expensive.

The differences are important because they create step changes in the price of thermal generation depending on the availability of plant which in turn affects the role of thermal capacity in ensuring reliable supply of electricity during peak periods and in moderating upward pressure on wholesale prices during peak periods.

The main factors affecting the costs of thermal generation used by the EA in its modelling of the short-run marginal cost (SRMC)[14] for its weekly trading conduct reports[15] are:

- Variable operating and maintenance costs (VOM) expressed in $ per MWh
- Fuel cost expressed in $ per GJ of fuel energy input multiplied by the heat rate (fuel energy input required per unit of electricity generated.
- Emissions costs which are the emissions from the fuel multiplied by the costs of the NZU

The VOM and heat rate are from the '2020 Thermal Generation Stack Update'[16] prepared for MBIE. The CO_2 equivalent (CO_2e) emissions for coal, natural gas and diesel are from Ministry for the Environment data[17].

The factors for the main thermal units are listed in Table 15 below.

14 'APPENDIX C: CALCULATING THERMAL SHORT-RUN MARGINAL COSTS' available at https://www.ea.govt.nz/documents/3111/Appendix_C_Calculating_thermal_SRMC.pdf

15 Available at https://www.ea.govt.nz/industry/monitoring/

16 '2020 THERMAL GENERATION STACK UPDATE REPORT, PREPARED FOR THE MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT, 29 OCTOBER 2020' available at https://www.mbie.govt.nz/dmsdocument/12554-2020-thermal-generation-stack-update-report-pdf#page=66

17 'Ministry for the Environment. 2022. Measuring emissions: A guide for organisations: 2022 detailed guide. Wellington: Ministry for the Environment.', Published in April 2022 and updated in August 2022, Table A1: Underlying data used to calculate fuel emission factors, pages 131-132. Available at https://environment.govt.nz/assets/publications/Measuring-emissions-guidance-August-2022/Detailed-guide-PDF-Measuring-emissions-guidance-August-2022.pdf

Table 15 Existing thermal generation

Capacity and SRMC drivers

Plant	Capacity	Type	VOM ($/MWh)	Fuel	Heat rate (GJ/MWh)	Emissions (tCO2e/GJ)
Huntly 1,3 and 4	750	Baseload	11.6	Coal	10.900	92.52
Huntly 1,3 and 4		Baseload	9.6	Gas	10.900	54.01
Huntly 5e3P	403	Baseload	5.2	Gas	7.400	54.01
Huntly 6 P40	40	Baseload	9.7	Gas	10.525	54.01
Taranaki Combined Cycle	377	Baseload	5.5	Gas	7.400	54.01
Stratford	210	Peaker	9.4	Gas	8.907	54.01
McKee	100	Peaker	9.4	Gas		54.01
Junction Road	100	Peaker	9.4	Gas		54.01
Whirinaki	155	Peaker	11.6	Diesel	10.906	69.39

Notes:

1 Table 3-12 Thermal generation plant operation designation, p53

2 Table 3-15 Previous and 2020 Recommended GEM variable operating costs (VOM), NZD/MWh, page 58

3 Table 3-13 Thermal generation plant heat rate, page 55

4 Estimates based on Ministry for the Environment data

Source: NZIER

The EA uses these factors to estimate an SRMC for thermal generation and use this as a one of its crosschecks of the competitiveness of wholesale electricity markets and analyse the impact of these costs on wholesale electricity prices in its weekly market monitoring reports.

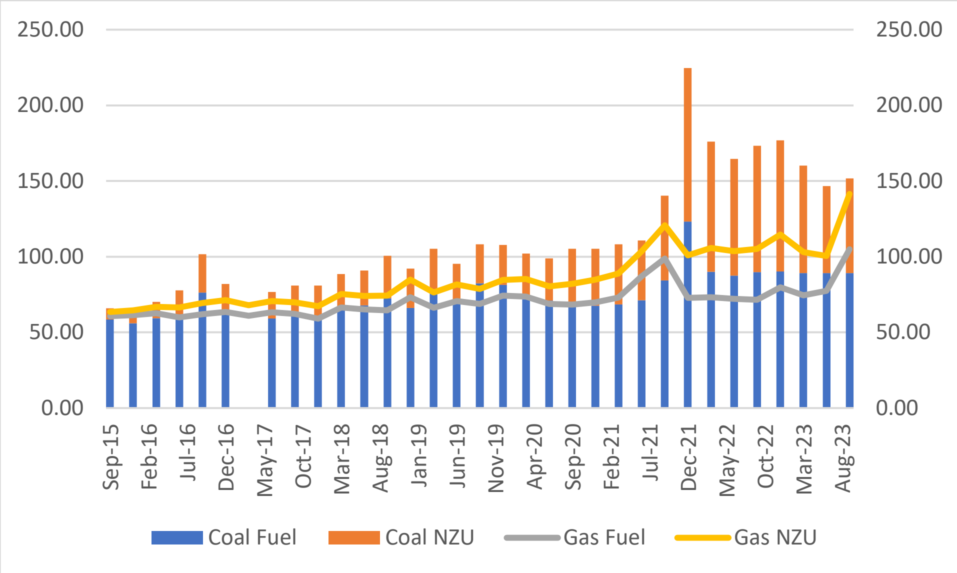
A.2 Genesis reported thermal generation cost

The operating reports provided by Genesis and Contact provide a cross-check of the assumptions used in the monitoring reports while a comparison of the reported thermal prices alongside the wholesale prices provides a crosscheck of the impact of thermal SRMC on wholesale prices. Figure 1 below shows the estimated quarterly average cost of fuel and emissions per MWh based on data reported by Genesis in its quarterly operating reports. These reports are not audited; however they provide a contrast to the SRMC estimation approach used by the EA. The main points are reported:

- Coal fuel cost is not based on market prices and lower than that used in the EA SRMC calculation.
- Gas generation (fuel plus emissions) cost is generally lower than coal generation cost. The increase in NZU prices from the second half of 2021 increased the average cost of electricity generated from coal by $40 per MWh more than electricity generated from gas. (This differential was almost eliminated in the three months to 30 September

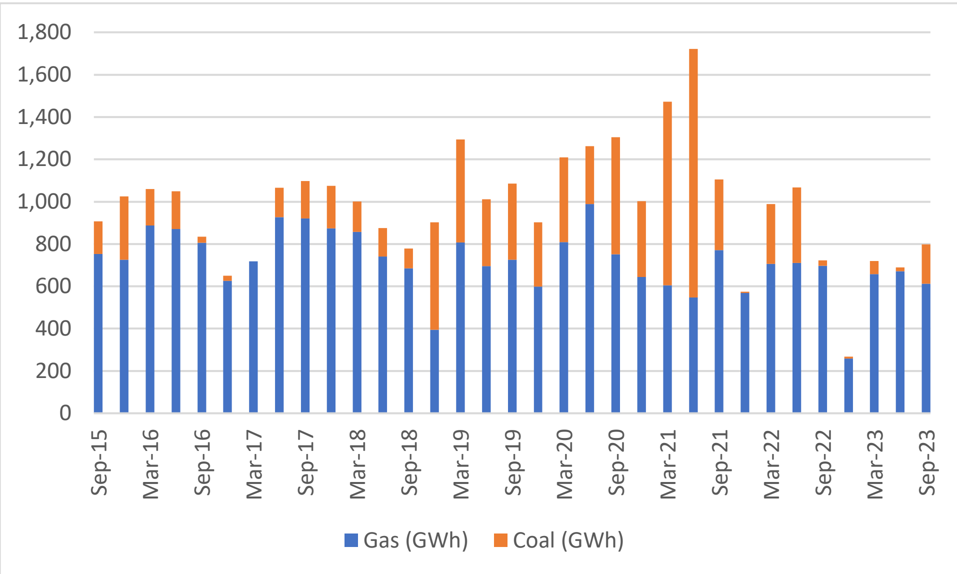
2023 because the Huntly Unit 5 outage forced Genesis to switch generation to the much (about 50 percent) less efficient[18] Huntly Units 1, 2 or 4 (Rankine Units).

Figure 1 Estimated Genesis generation fuel and emissions costs in $/MWh



Source: NZIER

Figure 2 Genesis thermal generation by fuel type in GWh



Source: NZIER

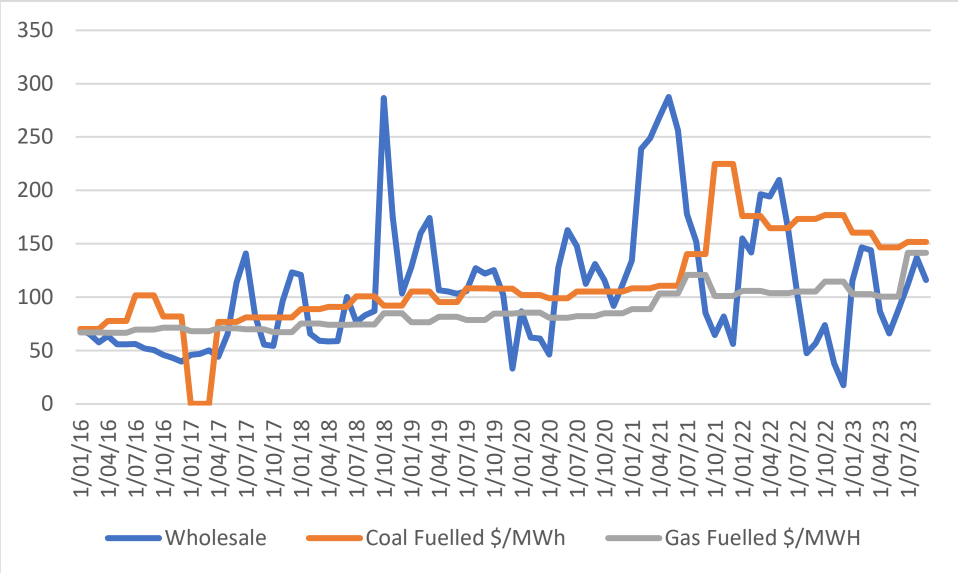
As illustrated in Figure 2 above in Genesis has used gas generation first to meet demand when it is available and only used coal as a generation fuel when gas capacity was fully committed or in situations such as the six months ended 30 June 2021 when Genesis was responding to a system-wide shortage of capacity. While the use of thermal capacity is

18 The heat rate for the Rankine Units is 10.9 GJ per MWh on coal or gas which is 47 percent higher than the heat rate for Huntly Unit 5 e3P of 7.4 GJ per MWh.

associated with higher wholesale prices the SRMC thermal capacity does not appear to automatically 'drive' or 'cap' wholesale electricity prices as illustrated by the simple analysis in in Figure 3 below which compares the quarterly average fuel cost (coal or gas plus emissions) reported by Genesis with generation weighted average monthly wholesale electricity prices obtained from the EA dataset[19]. A few key observations from Figure 3 are:

- During the period December 2019 to April 2020 when wholesale prices were low gas and coal generation were running at normal levels for Genesis but the average wholesale prices were below the average fuel cost.
- During the period January to June of 2021 Genesis electricity output was unusually high but average wholesale prices were more than double the estimated fuel costs.
- From the end of October 2021 coal fuel costs have been at or well above wholesale electricity prices but the volume of coal fired generation has varied between average (January 2022 to June 2022) and near zero for July to 2021 to September 2021 and September 2022 to June 2023.

Figure 3 Wholesale prices and Genesis fuel cost ($per MWh)



Source: NZIER

Nearly all of the Genesis thermal capacity is slow start baseload generation. This should mean that the generation weighted average wholesale price is a reasonable comparator for the average fuel price.

For the fast start thermal peaker capacity a more granular analysis would be required based on trading period (half hourly) price and generation data. The Contact operating reports suggest that the actual heat rate averaged between 10 and 14 GJ per GWh which is above the heat rates for the Stratford peaker and Taranaki Combined Cycle reported in Table 15. (The operation of Taranaki Combined Cycle plant in combined cycle (more efficient than open cycle) is limited and the remaining life of the plant is uncertain with plans to retire the plant in 2023.)

19 See https://www.emi.ea.govt.nz/Wholesale/Reports

A.3 Impact of ETS on thermal generation SRMC

The ETS has a direct impact on the fuel cost of operating thermal generation through increase in the price of NZU and an indirect impact through its influence on investor decision about the development of fuel sources (extending production from existing natural gas fields) and choice of new generation plant. The direct effect can be reliably calculated based on emission factors (see Table 16) and does not shift the SRMC for existing peaking thermal generation outside the range for wholesale prices modelled in the MDAG analysis.

Table 16 Impact of NZU price on coal and gas cost

NZU cost in $ per tonne of CO2e, Coal and Gas ‘Fuel’, ‘NZU’ and ‘Total’ costs in $ per MWh

	Emissions cost		Coal fuel SRMC			Gas fuel SRMC		
NZU	Coal ($/GJ)	Gas ($/GJ)	Fuel	Emissions	Total	Fuel	Emissions	Total
			89.13			75.97		
60	5.55	3.24		62.57	151.70		25.09	101.06
75	6.94	4.05		78.29	167.42		31.40	107.37
100	9.25	5.40		104.39	193.52		41.87	117.84
125	11.57	6.75		130.49	219.62		52.34	128.31
150	13.88	8.10		156.59	245.72		62.81	138.77
160	14.80	8.64		167.03	256.16		66.99	142.96

Source: NZIER

The indirect effect of investor decisions on the increased cost of natural gas and the reduced reliability of supply are harder to estimate. Modelling by Concept Consulting for the EA consultation on an orderly transition away from thermal generation[20] assumed a gas cost of $8.30 per GJ in 2025 (which is lower than the current cost of $ 9.80 per GJ reported by Genesis for the year to 30 June 2023) rising to $13.10 per GJ by 2032 (plus $8.10 per GJ for emissions). This total gas fuel cost of $21.20 per GJ translates to a fuel cost for generation of $164.40 per MWh in 2032.

The Concept Consulting base case modelling for thermal generation returns in 2025 and 2032 which uses 40 years of weather patterns also includes the following observations:

- Thermal generation will fall from an average of 12 percent of output (within a band of 5 percent to 20 percent of output) in 2025 to an average of about 2 percent of output (within a band 0 percent to 5 percent of output) in 2032.
- There is no commercial case for investment in new thermal capacity over the period modelled. Although all existing thermal plant should have positive cash flows in 2025, only one of the Huntly Rankine Units will be required (a reduction in baseload capacity

[20] ‘Potential demand for thermal generation in the transition to a renewables-based electricity system, Prepared for the Electricity Authority, May 2023’, Concept Consulting available at https://www.ea.govt.nz/documents/3147/Appendix_C_-_Concept_Consulting.pdf . The report ‘Potential demand for thermal generation ….’ was published by the EA as ‘Appendix C’ of its report ‘Ensuring an Orderly Thermal Transition, Consultation paper, Published on: 13 June 2023’ available at https://www.ea.govt.nz/documents/3148/Ensuring_an_Orderly_Thermal_Transition_6_June_20231397102.1_1.pdf

of 250 MW. Huntly Unit 5, the existing gas peakers and Whirinaki will all still generate positive net cashflows in 2032.

- While most the net cashflows for most of the weather year simulations in both 2025 and 2032 are tightly clustered around the mean, in 2025 and 2032, there are 5 and 4 outliers respectively with cash flows substantially above the mean indicating a high demand for thermal for generation capacity in about 10 percent of the weather years modelled for the base case scenario.

Appendix B Effect of intermittency

B.1 Problem definition

The long run average output of wind and solar generation is relatively stable but is often well below the name-plate capacity and can remain at low levels for multiple trading periods. This creates two challenges for maintaining reliability of output in a generation system with high levels of intermittent capacity:

- Forecasting when other generation capacity or demand response to allow time to activate these resources. (The EA and System Operator are both working on measures to improve weather forecasting and altering bidding and dispatch processes to better manage the difference between expected and actual intermittent generation as part of the generation dispatch decision-making).
- Ensuring the right levels of either additional generation capacity or demand responses are available to cover a generation shortfall and can be sustained for the duration of the shortfall. This is a more difficult problem to address than improving the forecasting primarily because the possible range of required additional capacity is large and the system reliance on intermittent capacity is projected to increase from less than 10 percent in 2020 to more than 40 percent by 2035.

The MDAG and EA modelling work address the problem of intermittency by modelling different weather years, but the results tend to be reported as averages and ranges shown in charts. This makes it difficult to assess the size and scale of the back-up generation or storage or demand response required. Transpower in its Security of Supply Assessments[21] allows for the intermittency risk by assessing the 'Capacity Contribution' from new generation as a percentage of its nameplate capacity[22]. The capacity contribution from new wind generation is 25 percent of nameplate capacity and for solar is 5 percent of nameplate capacity compared with 91.7 percent and 97 percent of nameplate capacity for new geothermal and battery capacity respectively.

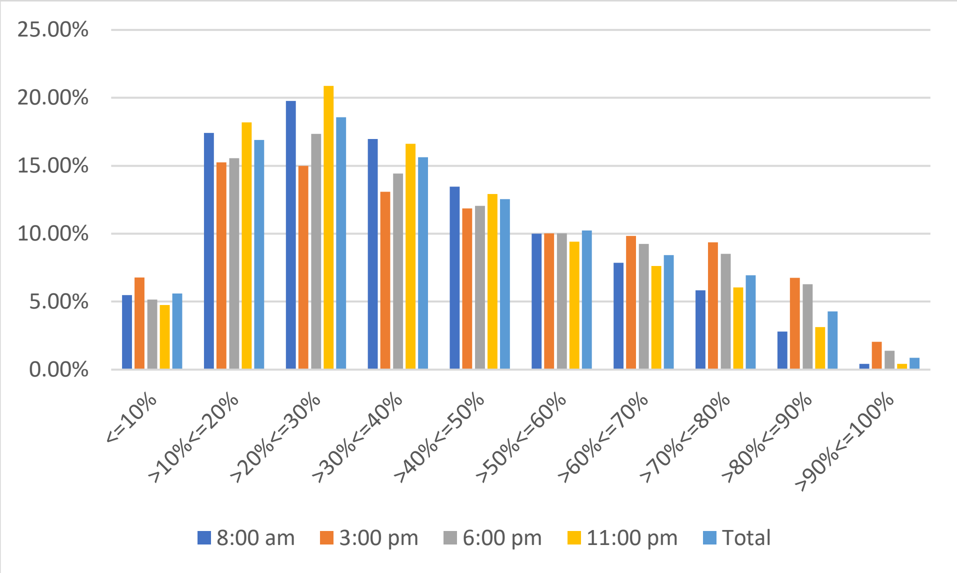
Figure 4 below provides an illustration of the variability in simulated wind generation output for exiting wind farms by showing the proportion of time (shown on the vertical axis) for a given time of day (trading period) over the simulation period 1 January 1995 to 31 December 2016 that a wind farm would be generating at a given proportion of its nameplate capacity (show in 10 percent bands on the horizontal axis. For example the simulation indicates that:

21 Security of Supply Assessment 2023, System Operator, Version: 2.0, Date: 26 June 2023

22 2023 SOSA - Final Supplementary Data - Final Version.xlsx" 'New Supply', A20:S26.

- About 5 percent of the time wind farm output will be less than or equal to 10 percent of nameplate capacity but that they seldom operate above 90 percent capacity
- About 45 to 50 percent of the time wind farms will generate between 10 percent and 40 percent of their nameplate capacity.

Figure 4 Proportion of time generating at each capacity range



Source: NZIER analysis of wind simulation data for existing wind farms t from Poletti & Staffell, 2021[23]

Appendix C MDAG Competition analysis

MDAG analysis of competition issues in 2022 found evidence for the following propositions:

- Established generators with large flexible generation resources are likely to have the capacity to increase 'volatility of volatility' and are insulated from the cost of increasing 'volatility of volatility'.
- Increased 'volatility of volatility' is likely to deter the entry of new intermittent generators which in turn is likely to increase the returns earned by established generators with large flexible generation resources.

In reaching these conclusions, MDAG estimates the size of the incentives for incumbent generators to block entry of new competitors. The measures used by MDAG are changes in mean gross margin and cashflow at risk (based on modelled price duration curves

In addition MDAG notes the following:

23 Stephen Poletti and Iain Staffell (2021). Understanding New Zealand's Wind Resources as a Route to 100% Renewable Electricity. Renewable Energy, Renewables.ninja dataset from Poletti & Staffell, 2021. The dataset is available at https://zenodo.org/records/4314878,

- Flexible peak capacity falls from 4,984 MW now to 3,563 MW in 2035. Although the competition issues analysis compares 2022 to 2035 – the retirement of gas and coal fired thermal capacity is expected to occur before 2035 (limiting the thermal capacity to 600 MW of biofuel or hydrogen).

Price duration curves will become steeper than they are now and compared to the initial 2021 modelling. This will make the cost of 'firming' intermittent generation capacity much higher than at present and increase the proportion of wholesale electricity cost at peak period beyond the already levels described below.

C.1 MDAG price duration curve scenarios

The MDAG competition analysis paper presents graphs of price duration curves for five scenarios[24]:

- Base – central reference case with two sensitivity cases:
  - Less bang-bang – lower volatility than base
  - More bang-bang – higher volatility than base
- Entry new generators:
  - Deterred
  - Encouraged.

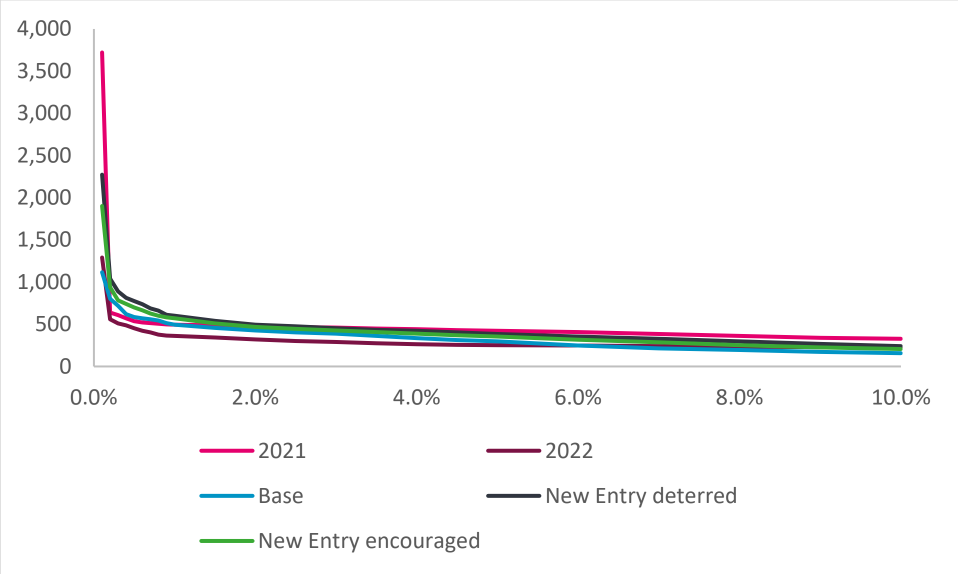
The trading period bands are reported in the following sizes:

- 0.1 percentage point for <=1 percent of trading periods
- 0.5 percentage point for >1 percent to <=5 percent of trading periods
- 1.0 percentage point for >5 percent to <=99 percent of trading periods
- Final bands of >99.0 to <=99.5 percent, >99.5 to <=99.9 percent and >99.9 to <=100.0 percent

The forecast price duration curves have a much steeper left-hand side (10 percent of trading periods with the highest prices) but are flatter with lower prices for the remaining 90 percent of trading periods than recent years. Figure 5 and Table 17 show the MDAG competition analysis 2022 price duration curve scenarios and the 2021 and 2022 price duration curves.

24 MDAG competition issues 2022, page 20. The MDAG price duration data in the following charts and tables was extracted from the MDAG competition issues 2022 paper by displaying and copying the data labels from the slides.

Figure 5 Price duration curves 10 percent of trading periods with highest prices



Source: NZIER

The projected prices for the 10 percent of trading periods with the highest prices for the base reference case are lower than the prices for either of the new generator scenarios. The prices for the new generator deterred are about 10 percent above new generator encouraged scenario. The actual prices for 2021 and 2022 have a similar shape to the MDAG projections for the 10 percent of trading periods with the highest prices. (Table 17 is included because the very high prices for 0.1 percent of trading periods obscure the differences between price for the next highest priced 9.9 percent of trading periods.

Table 17 MDAG Price duration curve – top 2

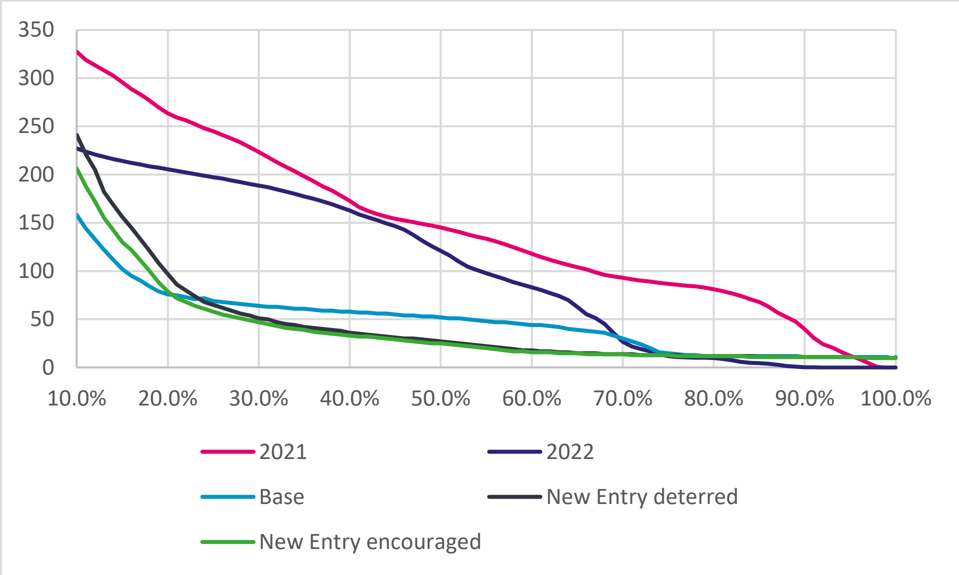
All data reported in $ per MWh unless otherwise stated.

Trading period band	Less bang-bang	Base	More bang-bang	New Entry encouraged	New Entry deterred	2021	2022
<= 0.1%	1,040	1,116	1,973	1,900	2,273	3,719	1,290
>0.1% to <= 0.2%	761	804	1,005	940	1,042	638	559
>0.2% to <= 0.3%	686	719	852	784	888	610	510
>0.3% to <= 0.4%	597	621	776	743	814	572	489
>0.4% to <= 0.5%	567	586	747	699	776	537	455
>0.5% to <= 0.6%	536	572	709	665	739	522	425
>0.6% to <= 0.7%	520	561	679	628	689	514	404
>0.7% to <= 0.8%	498	544	622	600	661	506	378
>0.8% to <= 0.9%	474	515	607	584	612	501	369
>0.9% to <= 1.0%	460	496	588	571	603	498	363
>1.0% to <= 1.5%	414	457	523	509	540	489	345
>1.5% to <= 2.0%	380	426	482	469	496	480	320
>2.0% to <= 2.5%	356	405	456	445	477	470	303
>2.5% to <= 3.0%	323	389	436	426	453	460	289
>3.0% to <= 3.5%	302	363	421	409	436	451	275
>3.5% to <= 4.0%	275	336	406	391	424	442	265
>4.0% to <= 4.5%	256	315	386	369	406	432	258
>4.5% to <= 5.0%	235	297	369	355	385	424	254
>5.0% to <= 6.0%	207	251	337	317	355	408	248
>6.0% to <= 7.0%	186	217	304	287	328	386	241
>7.0% to <= 8.0%	171	195	275	255	298	362	236
>8.0% to <= 9.0%	162	174	243	228	267	342	231
>9.0% to <= 10.0%	156	158	225	206	241	327	227

Source: NZIER analysis of EMI data

Figure 6 shows that recent actual prices for the remaining 90 percent of trading periods are generally higher than the MDAG projected prices. Also, the reference base case scenarios switches from being below to being above the new generator scenarios for the middle range of trading periods (25th to 75th percentile).

Figure 6 Price duration curves 90 percent of trading periods with lowest prices



Source: NZIER