Electricity Authority's
Market Monitoring Review of
Structure, Conduct & Performance in the
Wholesale Electricity Market

Contact Energy Submission

22 December 2021

Executive Summary

1. Contact Energy supports the Authority's wholesale market competition review. The Authority has an important role in monitoring the efficient operation of the electricity market.

2. Overall the review appears to show that the market is operating well. Market power as measured by the HHI is moderate and declining, there is no clear evidence of any problems stemming from vertical integration, significant new generation continues to be built, and prices tend to reflect underlying supply and demand conditions.

3. Furthermore the market is producing good outcomes for New Zealanders. New Zealand ranks ninth in the world in the World Energy Council's energy trilemma of Security, Sustainability and Equity.

4. The sector is now entering into a period of intense investment to both decarbonise existing generation and develop new generation to meet future demand. It is more important than ever that the market is provided with reasonable certainty on regulatory settings, and that government intervention only happens when there is a demonstrable issue to address.

5. The Authority appears to be expecting a level of perfection in the market that is simply not attainable in a dynamic market that operates in real time. No concrete substantive issues have been identified.

6. The Information Paper tentatively concludes that 'prices *may* not be being determined in a competitive environment' over a relatively short period between 2019 to mid 2021. However, the paper acknowledges that none of the suggested reasons in isolation provide concrete evidence of a structural, competition or performance problem. The analysis ignores the links to the wider environment, and high-level metrics demonstrate that New Zealand continues to deliver to the energy trilemma.

7. A more thorough review of the evidence shows that the concerns found by the Authority are better explained by a risk premium related to uncertainty in the gas market, rather than any market power issues. The Authority's models will be very sensitive to the input assumptions, and the gas price it uses does not include a risk premium.

8. The Authority also suggests that the New Zealand Aluminium Smelter contract may have resulted in some allocative inefficiencies. We disagree. The Smelter contract was negotiated under very unusual circumstances in January 2021. It should not be taken as evidence of a more systemic issue. Contact asked NERA to assess the Authority's model and conclusions reached. NERA's attached report concludes that "the evidence is not sufficient to make such a finding in respect of the Meridian and Contact CFDs."

9. The Authority has not built a sufficient evidence base, nor considered wholesale market performance and the link to long term market outcomes, that would support any of the interventions put forward. The risk of unintended consequences is significant.

Introduction

10. Contact Energy welcomes the opportunity to submit on the Electricity Authority's wholesale market competition review. While we support the Authority's important role monitoring the performance of the market, Contact does have concerns with the process, analysis and preliminary conclusions reached.

11. This submission provides broader context on the electricity market, the energy trilemma, the government's climate priorities and our ambitions in the transition to a more sustainable electricity system. New Zealand continues to perform extremely well on the highest-level metrics captured by the energy trilemma of security, sustainability and equity. The sector is also entering a period of intense investment to both decarbonise existing generation and develop new generation to meet future demand. Market certainty is more important than ever.

12. The submission then responds to both:

    - the information paper regarding the market monitoring review (**Information Paper**) on the structure, conduct and performance in the wholesale electricity market since the Pohokura outage in 2018; and
    - the discussion paper regarding inefficient price discrimination in the wholesale electricity market (**Price Discrimination Paper**).

13. Neither paper identifies concrete substantive issues, but rather puts forward potential indicators and suppositions. Regulatory or government intervention on this basis is likely to cause greater inefficiencies than it is intended to solve.

Contact is focussed on the transition to a more sustainable electricity system

> *Our policy to bring forward decarbonisation of our electricity system faster - to 2030 instead of 2035 – is ambitious, but is exactly the kind of purpose we need to urgently address the drivers of climate change…*
>
> *Transitioning to a net-zero economy will require significant system change and the energy sector will have to do some heavy lifting.*
>
> Minister of Energy and Resources, Speech to Carbon and Energy Professionals NZ 26 May 2021.[1]

14. The energy sector is undergoing one of the most significant changes in its history. The Climate Change Commission estimates that electricity generation will need to increase by 50% by 2035. The sector must also make significant investment to replace thermal plant with more sustainable energy sources.

15. While the Authority's objective does not expressly include decarbonisation, it is the Government's stated ambition that New Zealand will move to 100% renewable generation by 2030, and additionally that electrification will be pivotal to broader decarbonisation of New Zealand, including the electrification of process heat, reduction in residential fossil fuel gas use and transportation.

16. Contact is committed to playing our part in this change. It is central to our Contact26 strategy to lead New Zealand's decarbonisation. We have established science-based emissions reduction targets, committed to decarbonise our generation portfolio, and have formal Board oversight of climate related matters.

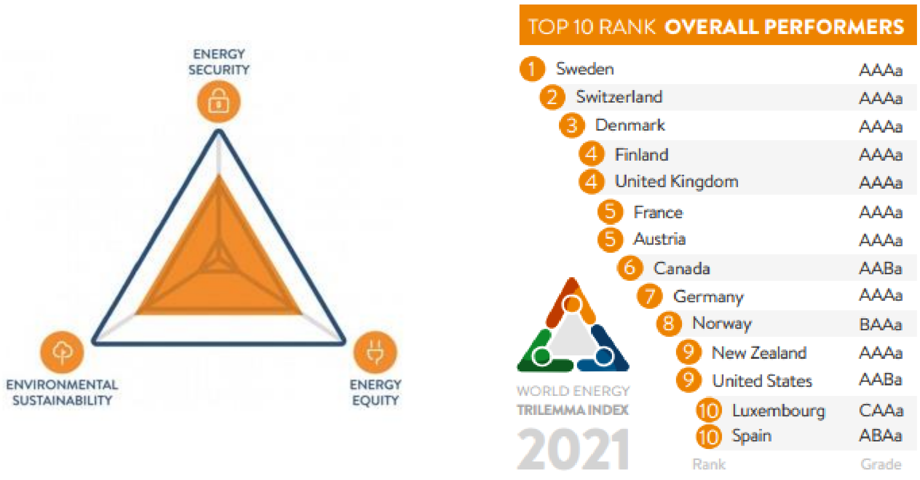
The electricity market is starting this transition from a solid foundation

17. The sector is starting this journey in a strong position, ranking in the top 10 of the World Energy Council's energy trilemma, and is the only country outside Europe to achieve an AAA rating across the three metrics. In its analysis, the Authority fails to link either its tentative findings or proposed changes to either the Authority's own statutory purpose or the broader market context.

18. The energy trilemma is a three-dimensional problem that involves balancing the security of energy supply with environmental sustainability and affordability. It neatly provides a framework for articulating the areas where Contact puts its energy to create sustainable value for New Zealanders; we're working hard to improve accessibility, demonstrate reliability and look after the environment. The trilemma also demonstrates the competing demands and trade-offs at play. Pushing harder on one dimension of the trilemma may require concessions from the others.

[1] https://www.beehive.govt.nz/speech/speech-carbon-and-energy-professionals-nz

Figure 1: World Energy Council trilemma



Source: World Energy Council

19. This ranking is supported by other key metrics of industry performance.

- MBIE data shows that energy prices have fallen in real terms. Since 2014 the average annual residential power bill has fallen by almost $200 in real terms. New Zealand household power prices are the 8th cheapest in the OECD.
- Renewable investment - Annual renewable electricity use has increased by 9,000 GWh in the last 15 years. In 2021 alone, three significant renewable generation projects have begun construction.

We are committed to the decarbonisation challenge

20. The New Zealand energy sector cannot rest on its current performance. We share the Government's ambitions to decarbonise our economy and are fully aware of the size of the challenge.

21. Significant investment in new renewable energy is required to both displace existing thermal generation and meet expected new demand. To achieve this will require a market environment that provides reasonable certainty to support investment decisions made over a time horizon of 20 – 30 years, not based on the short timeframe of the Authority's current analysis. Critical market conditions include:

- **Undistorted wholesale market price signals** which provide a critical incentive for investment in new generation. Renewable generation is lower cost and will displace existing thermal generation – resulting in lower cost energy in the long term for New Zealanders.

Box 1: What is Contact doing to meet the decarbonisation challenge?

- We have set science-based emissions reduction targets to
  - reduce our Scope 1 and 2 greenhouse gas emissions by 45% by 2026
  - reduce our Scope 3 emissions from use of sold products by 34% by 2026
- We have recently released a report recommending the development of an industry-led ThermalCo to manage and reduce future volatility through the transition to fully renewable generation in New Zealand.
- We are planning a number of new renewable generation plants, such as the $580m Tauhara investment, a 152MW geothermal station near Taupō

- **Reasonable demand certainty over the long term.** While demand has been comparatively flat for a significant period, expectations are that demand will begin to grow over time. Significant and sudden reduction in demand (such as a rapid Tiwai or industrial exit in the short term), or failure to grow demand in the medium term, will both reduce the need for, and investment case, to build new renewable generation to meet decarbonisation objectives.
- **Reasonable regulatory certainty**. Certainty will accelerate commitment to further generation investments. Constant changes to either regulatory settings or inconsistent views on the structure of the industry such as vertical disintegration will have a chilling impact on investment.

22. New renewable generation will not be built where there is insufficient demand or market-based pricing signals don't occur. Investor confidence will also be significantly impacted by uncertainty.

23. A clear case in point was the announcement of multiple renewable generation projects after confirmation that NZAS had committed to staying until at least December 2024. This included:

    - Contact's $580m Tauhara investment in a 156MW geothermal station near Taupō. This project had previously been put on hold because of NZAS uncertainty.
    - Meridian's $395m Harapaki investment in a 176MW 41 turbine windfarm in the Hawkes Bay. In August 2020, the Meridian Board had shelved the project because of the Tiwai exit[2] but was confirmed in February 2021.[3]

[2] https://www.nzherald.co.nz/hawkes-bay-today/news/hawkes-bay-windfarm-shelved-because-of-tiwai-point-closure-plan/KUBJSMBRCI5TFMEK4R57XWTY7A/

[3] https://www.meridianenergy.co.nz/news-and-events/meridian-to-build-395-million-wind-farm-in-hawkes-bay

Other market changes already underway

24. Alongside the decarbonisation challenge, there are a number of other workstreams already underway that should be factored into the Authority's analysis. Many of these changes should ameliorate the Authority's preliminary concerns and further reduce any justification for further intervention.

25. They include:

- The new High Standard of Trading Conduct rule that the Authority has put in place. This must be allowed sufficient time to be embedded and tested. The Authority has the tools and experience to increase compliance should it be necessary for those periods where the Authority considers the spot market has materially departed from competitive outcomes
- Changing domestic demand from further electrification of the home including electric vehicle uptake, transition away from gas to electricity for heating and cooking, partially offset by improvements to home energy efficiency.
- Changing demand from industrial users – changes to industrial allocations of NZUs for HITE (High Intensity, Trade Exposed) industry impacting demand, new technologies and the electrification of process heat.
- MDAG price discovery project in the wholesale electricity market under 100% renewable electricity supply. MDAG note that "projections generally suggest that new renewable generation will need to be built at a rate materially faster than the industry achieved over the market's first 15 years."
- Upcoming changes to the Transmission Pricing Methodology (TPM) that will materially impact the allocation of transmission charges.
- Significant investment required to upgrade both transmission and distribution networks to support future demand and rebalancing of the network.

The Authority's review has not found significant issues in the market

26. This part of our submission responds to the Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market since the Pohokura Outage in 2018: Information Paper.

27. The Information Paper found an unexplained uplift in the spot market since the Pohokura outage that the Authority could not explain in its analysis. The Authority concludes there is "some evidence to suggest that prices may not have been determined in a competitive environment".4

28. Our submission explains that the Authority's tentative conclusion is not supported by the evidence.

    - The analysis does not sufficiently demonstrate a case that meets any reasonable threshold for intervention.
    - Gas uncertainty explains the uplift in spot prices since 2018 rather than any posited market power issues.
    - The Authority already has sufficient tools to monitor, investigate and correct any trading periods where it considers the market has departed from competitive outcomes.

The case for intervention has not been sufficiently made

29. The Authority's analysis seeks to understand the wholesale market's performance over a short period from January 2019 to mid-2021. During this time there was significant volatility in the gas market; and low water levels in both the South and North Islands. The Authority identifies that this led to historic volatility and high prices.

30. While the report appears to acknowledge the market is performing adequately, the report concludes that there are periods where these competitive dynamics are less clear, while also recognising the limitations of the analysis it has undertaken.

31. This is an extremely weak basis on which to consider intervention. We have two main areas of concern with the approach the Authority has taken to this analysis:

    - Expecting perfection in a highly complex real-time market.
    - Failing to adequately consider the impact on longer term dynamic efficiency.

The electricity market performs well – perfection is not the right standard to aim for.

32. The Authority's analysis of the structure conduct and performance of the market shows that the market is generally performing well. As noted by the Authority "the performance of a competitive market is ultimately one that satisfies the conditions of allocative, productive and dynamic efficiency".

[4] EA Market Monitoring Review – Information Paper, October 2021, page ii.

- HHI has been steadily declining since 2004, and currently sits just below 2000, which is generally considered as only mildly concentrated.
- Meridian is required to meet demand 90% of the time, however, its market share is well below common thresholds for considering market power.
- The largest generators are vertically integrated, however there is no evidence that this causes adverse outcomes. As the Authority notes, vertical integration “can often be efficient because it can reduce transaction costs, lower the cost of capital for building new generation, or facilitate better risk management.”[5]
- Significant new generation has been built and continues to be built by large generators, which is expected given their knowledge of the market and access to capital. However, during the review period, all three new generation plants were built by new entrants (one has subsequently changed ownership to Mercury).
- Over the review period prices have tended to reflect underlying supply and demand conditions.
- A high percentage of offers are above cost in the review period. This is explained by the treatment of gas supply risk as we discuss in the following section.
- There are some instances of higher Lerner indices, however, as the Authority notes these are very sensitive to cost estimates, and typically do not persist over time.
- No dependable evidence that economic withholding has occurred.

33. This analysis does not include any empirical support for the Authority’s tentative suggestion that ‘prices may not be being determined in a competitive environment’. As the Authority acknowledges, none of the suggested reasons in isolation provide concrete evidence that there is a problem.

34. On a forensic examination any market will be found to have some imperfections. The electricity market operates 24/7 with generators simultaneously managing both real time and future demand requirements for generation, alongside operational and safety requirements including managing fuel and weather volatility. Ex post 20/20 hindsight will always identify periods where the market could have operated more effectively. And indeed, the Authority has the tools with the UTS and High Standards rules to address these concerns should they arise.

The Analysis fails to adequately consider longer term dynamic efficiency

35. The Authority has undertaken a comparatively short-term analysis of the wholesale market. The analysis appears to completely ignore the wider environment, and high level metrics demonstrating that the market is achieving the energy trilemma (as covered in part 1 of this submission).

36. Any minor imperfections found in this static analysis need to be considered in the context of the material impact that government intervention can have on long-term dynamic efficiency, such as harming the incentives for investment required in new renewable generation, transmission, and distribution.

[5] EA Market Monitoring Review – Information Paper, October 2021, para 5.27.

37. As covered above, the electricity market is going through one of the most significant transformations in its history as it looks to deliver on the Government's decarbonisation ambitions. Contact is committed to playing our part, but doing so requires a robust regulatory system consistent with the principles for regulatory best practice.

38. The stated intention to explore further options for intervention on the back of such weak evidence (and despite the strong performance of the sector shown in Part 1 of this submission) does not provide the right conditions for investment. It risks creating a perception that the regulatory regime is not certain, predictable, or proportionate.

39. While Contact supports the Authority's role in monitoring competition in the market, we believe that the Authority has failed to link short term static analysis to broader competition indicators in the market, and the Authority's own statutory objective "to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers" [emphasis added].

Box 2: The Treasury's principles for best practice regulation

- Durable
- Certain and predictable
- Proportional
- Growth focussed
- Transparent and accountable
- Capable regulators
- Flexible

Gas uncertainty explains the uplift since 2018

40. The Information Paper concludes that "Spot prices appear to have reflected underlying supply and demand conditions, but a sustained upwards shift has occurred since the Pohokura outage,"6 and that "[t]he detection of a structural break in later 2018 supports the proposition that some of the sustained upwards shift in prices post-Pohokura could be due to gas supply issues."7

41. We agree with this assessment. Our estimates (detailed at the end of this section) show that the increase in gas supply risk since the Pohokura outage is responsible for an increase in the spot price of at least $44/MWh. This fully explains the $39/MWh uplift seen on the dummy variable.

42. The lack of consideration of gas supply issues means that the Authority's model under-estimates the value of stored gas, particularly during periods of low storage. This is because some offers are made to reflect the risk that gas supply may become restricted, and diesel would have to be used instead (the energy supplier of last resort in the NZEM). In other words, the true opportunity cost of stored gas could far exceed the forward ASX electricity price curve price that the Authority have used.

43. Uncertainty in the gas market will then feed through into the value placed on any stored fuel, be it hydro, coal or gas. This is because all fuels act as substitutes.

[6] EA Market Monitoring Review - Summary Paper, October 2021, p.3
[7] EA Market Monitoring Review – Information Paper, October 2021, para 2.8.

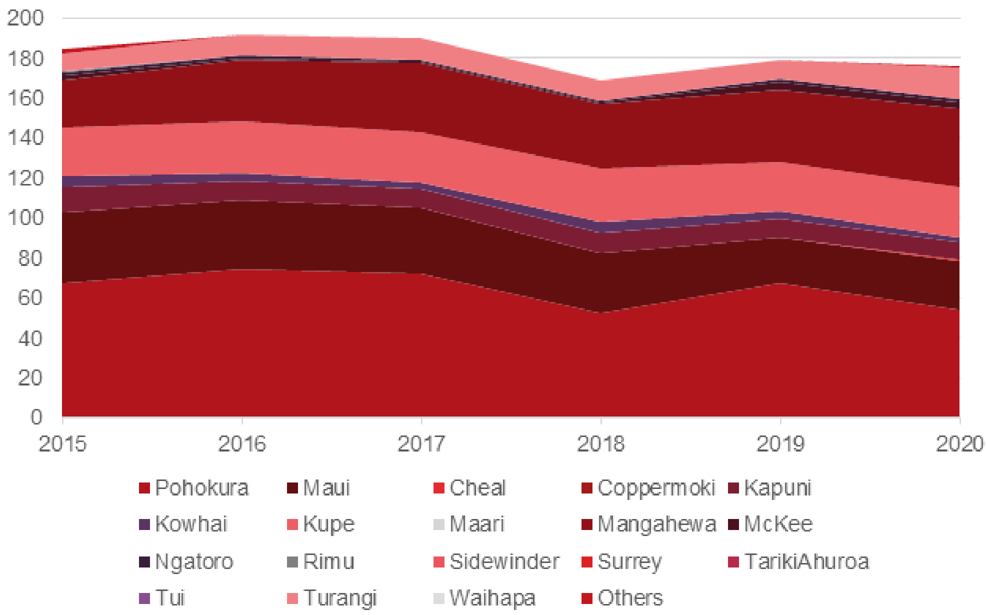
44. In addition, offers are likely to exceed SRMC due to the high maintenance costs associated with thermal units being dispatched on and off in short time frames which is more likely to occur if units are offered at close to SRMC.

45. These two effects explain the Authority's finding that Contact has a high Lerner index (margin above estimated SRMC) during periods of low storage. During periods of low storage the risk of gas shortages (and therefore the true opportunity cost of gas) is larger because there is a greater chance that diesel needs to be used instead.

Gas production has decreased

46. As shown in figure 2, total net gas produced has fallen from 190 PJ in 2017 to 176 PJ in 2020. Electricity generation accounts for approximately 31% of gas use in New Zealand so generation lost equates to at least 340-570 GWh/year. The reduction is particularly prominent at Pohokura, a field strongly linked with electricity generation in the past, where the reduction is 18 PJ from 2017-2020 which would be the equivalent of ~2TWh

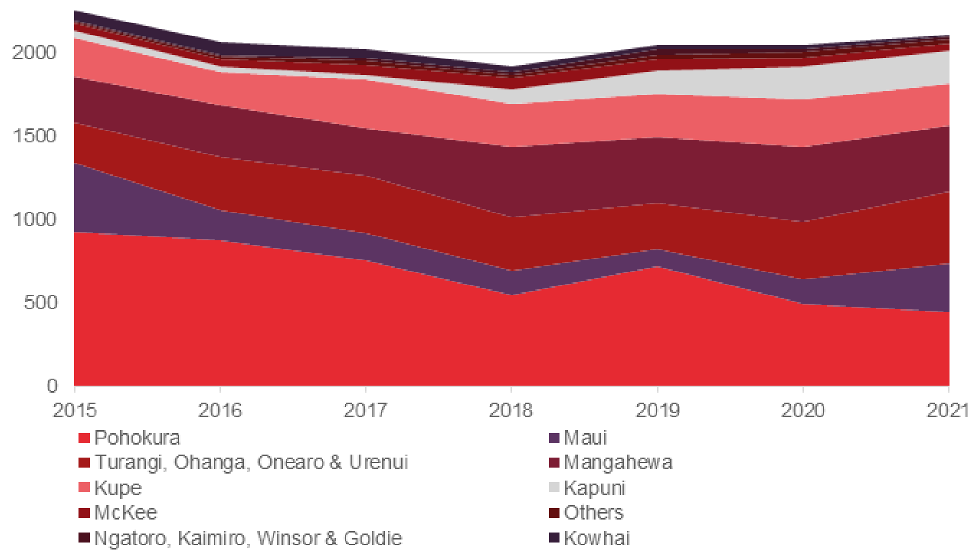
Figure 2: Net Gas Production (PJ/Annum)



Gas reserves availability remains clouded

47. Future gas available from Pohokura has decreased by 311 PJ since 2017. At the time Pohokura accounted for 37% of New Zealand's gas reserves. In 2021 Pohokura now accounts for only 21% of all reserves. Figure 3 shows that the decrease in Pohokura reserves has been offset by increases at Kapuni, Mangahewa and Maui however it remains to be seen how much of this gas makes its way to the electricity market.

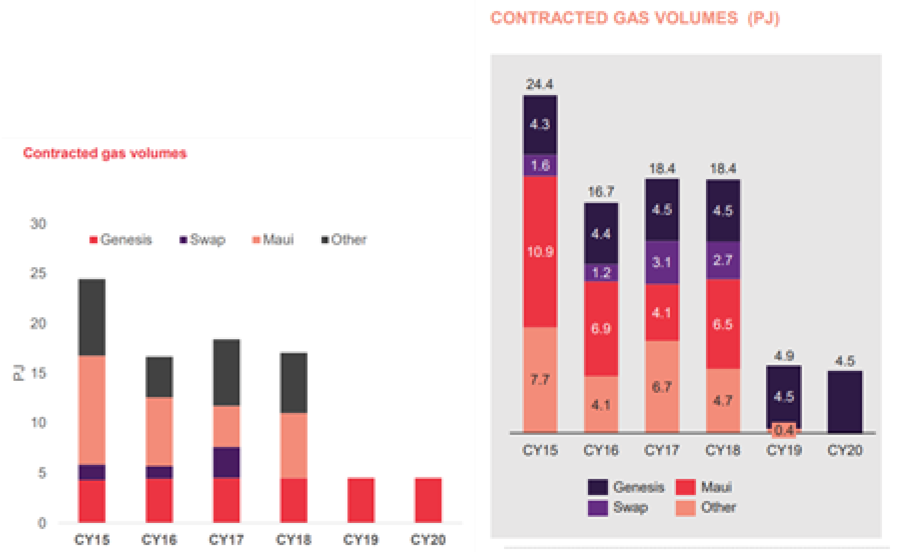
Figure 3: 2P Reserves (PJ)



Contact's ability to secure gas during this period was limited

48. Further evidence of gas uncertainty over this period is an excerpt from Contact Energy's 2019 Annual results showing the reduction in contracted gas volumes

Figure 4: Excerpts from Aug-18 and Feb-19 Annual Results



Recent gas production hasn't been as reliable as we would have expected and we continue to operate cautiously as we manage short-term supply constraints. Contact is engaging with suppliers to contract gas for calendar year 2019 and beyond. In addition to the gas we expect to contract, we have access to stored gas in AGS and other contractual options that will give us appropriate access to energy for our customers.

EMS gas price volatility has increased by over 300% since September 2018

49. Since September 2018 average EMS prices have doubled, but standard deviation has quadrupled (table 1 and figure 5). Volumes have increased but so has the volatility of daily volumes (table 1).

50. At the 90th percentile prices have increased by $12/GJ post September 2018, whilst at the 50th percentile they have increased by only $4/GJ (table 2).

51. The tightness of the gas market since September 2018 is also evident in Figure 5. Six of the seven months with average prices greater than $15/GJ (excluding carbon cost) had volumes traded that were below mean.

52. Figure 6 shows the monthly price distribution (as a boxplot) and overlays the Whirinaki break even gas price (at this gas price Contact is indifferent to dispatching the gas Peakers or burning diesel at Whirinaki). In some of the months with higher gas prices, the upper percentiles have begun to converge with the Whirinaki breakeven price.

Table 1: EMS gas prices (excluding carbon) and volumes before and after the first Poho outage

	Average price $/GJ	Price std dev $/GJ	Daily average TJ	Daily TJ std dev
before_outage	5.6	1.4	10.6	23.8
post_outage	11.6	5.8	18.5	52.4
post_outage_increase	6.0	4.4	7.9	28.6

Table 2: EMS gas price percentiles (excluding carbon) before and after the first Poho outage

	0%	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
before_outage	0.0	3.3	4.0	4.3	4.5	4.7	5.0	5.2	5.5	6.0	19.5
post_outage	0.2	5.7	6.7	7.5	8.1	8.7	9.5	11.1	13.7	18.2	55.4
post_outage_increase	0.2	2.4	2.7	3.2	3.6	4.0	4.6	6.0	8.2	12.2	35.9

Figure 5: EMS gas price distribution (excl carbon cost) before and after September 2018

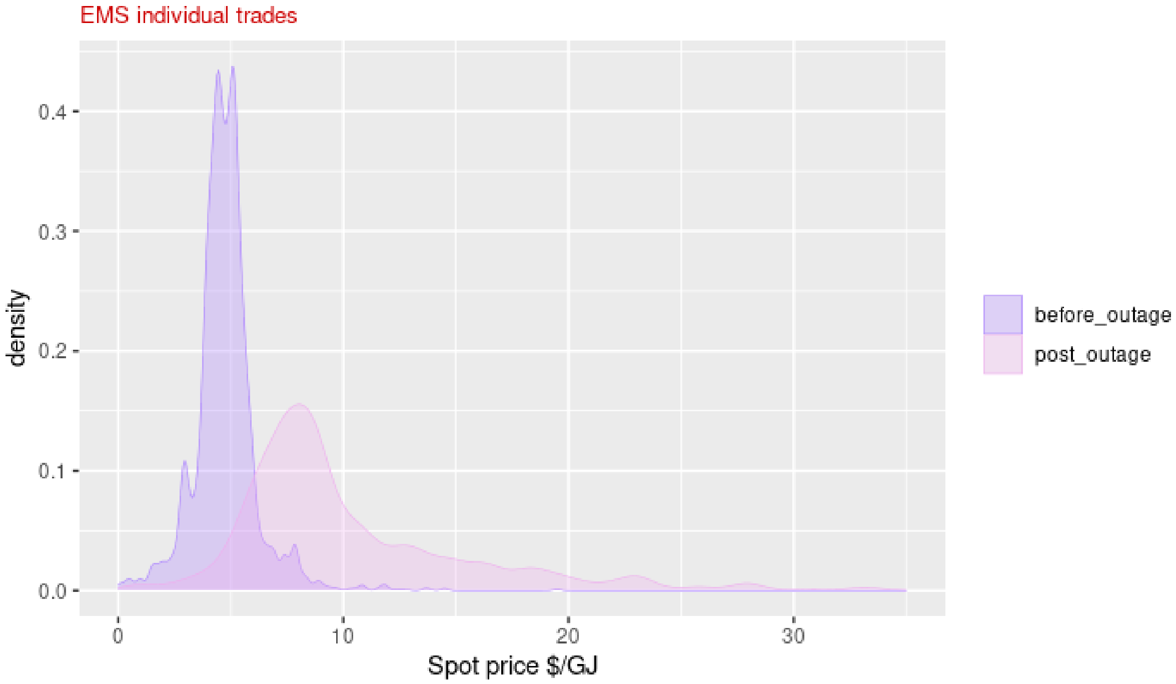


Figure 6: EMS monthly gas price boxplot distribution

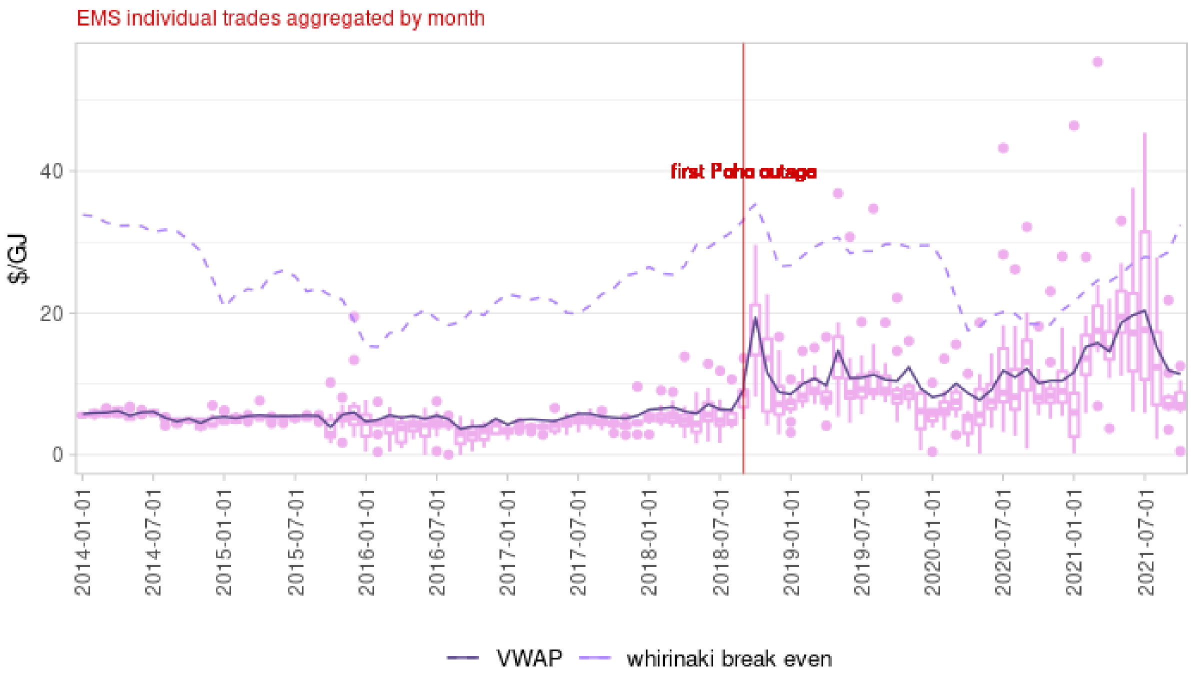
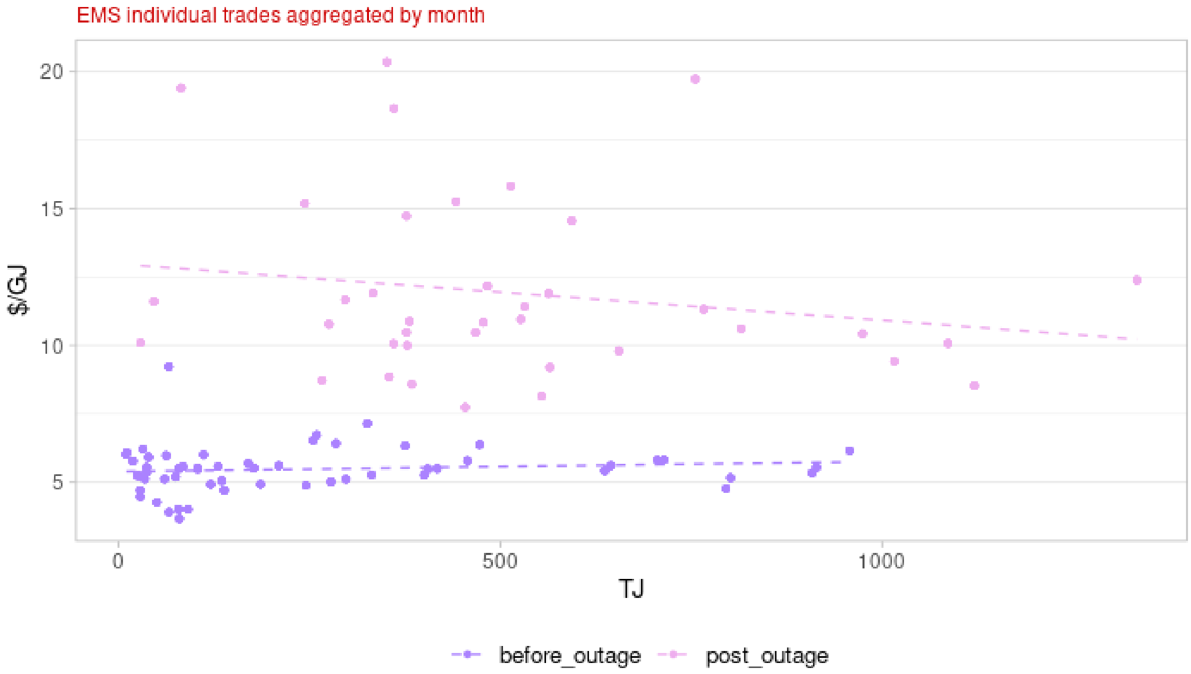


Figure 7: EMS monthly gas price versus volumes



Measuring the value of gas uncertainty

53. In the sections above we have shown that uncertainty in both the prices and volumes traded via EMS mean that marginal fuel purchases (on EMS) will include a risk premium, resulting in gas price assumptions that are higher than the EMS VWAP.

54. Precisely measuring the risk premium is difficult, however, we have identified a number of proxies that help determine the magnitude of the premium. These estimates of the risk premium more than account for the $39/MWh dummy variable in the Authority's structural break regression.

- The margin between the 50th and 90th EMS price percentile has increased by more than $6/GJ. Post October 2018, we can be 90% confident of purchasing gas at $18.20/GJ or less (table 2) from EMS, which is a $6.60/GJ premium over the mean price of $11.60/GJ. Before October 2018, the equivalent risk premium is only $0.40/GJ.
- The standard deviation of EMS gas prices has increased by $4.40/GJ since October 2018 (table 1)
- If generators cannot source sufficient gas from EMS, and AGS extraction and gas contracts are insufficient to meet demand, then a fungible product such as diesel should set the opportunity cost of stored gas (i.e. Whirinaki generation) which in turn sets the SRMC for the gas peakers. This would be a risk premium in excess of $10/GJ.

The Authority already has in place sufficient tools to address market issues

55. The Authority has the tools in place to monitor, investigate and correct any trading periods where it considers the market has departed from competitive outcomes. This includes the Undesirable Trading Situation and High Standard of Trading Conduct rules. Contact supports the Authority's increasing focus on monitoring and enforcement of these rules. The new trading conduct rules came into effect in 2021, following significant analysis and consultation by the Authority's Market Design Advisory Group. Time must be allowed for the Authority to increase its monitoring and enforcement function of this rule - a test requiring that operators always offer into the market on the basis that they face competition to dispatch their generation.

56. The Authority must remain vigilant for the misuse of these mechanisms by competing parties to use for personal promotion and competitive positioning rather than addressing any underlying issues in the operation of the wholesale market in both the short and long term.

The New Zealand Aluminium Smelter contract is not an indicator of a systemic issue

57. In this part of our submission we respond to the paper Inefficient Price Discrimination in the Wholesale Electricity Market – Issues and Options.

58. The Authority has undertaken a deep dive into the arrangements reached between New Zealand Aluminium Smelter (NZAS), Meridian Energy and Contact. The paper raises concerns that this contract, and others like it, have the potential for inefficient price discrimination.

59. This is not a systemic issue as suggested by the Authority. The attached analysis from NERA shows that any potential effect is materially smaller than estimated by the Authority and may not have occurred at all. If any inefficiency did occur it has only been found with detailed assessment in hindsight that is placing an unrealistic expectation of perfection.

60. In the following sections we:

- explain the unique nature of the NZAS contract meaning that the Authority's concerns identified in hindsight are unlikely to be repeated and should not be generalised;
- summarise NERA's attached analysis which shows there is a large amount of uncertainty in the Authority's conclusions; and
- conclude that the proposed intervention options are not a proportionate response.

The 2021 New Zealand Aluminium Smelter contract was negotiated at a unique point in time

61. In July 2020, Rio Tinto concluded a strategic review of the smelter at Tiwai Point and decided to wind down operations by August 2021. Rio Tinto noted that the business was no longer viable given high energy costs and a challenging outlook for the aluminium industry.[8]

62. This kicked off a series of negotiations between NZAS, Meridian, and the New Zealand Government. Ultimately, on 14 January 2021, NZAS reached an agreement with Meridian to provide 570MW of electricity to allow the Tiwai Point aluminium smelter to continue to operate until December 2024.9 Contact provided a hedge contract of 100MW of capacity to Meridian, in support of the NZAS contract.

63. The unique context and timing of the NZAS review is important and the resulting contract and terms heavily reflect the challenges faced at the time, including:

- transmission constraints;
- credible threat of exit;
- no viable alternative demand opportunities;

[8] Rio Tinto Media Release, *NZAS terminates electricity contract and plans to wind-down operations following strategic review*, 9 July 2020

[9] Rio Tinto Media Release, *NZAS reaches deal with Meridian to extend operations to 2024*, 14 January 2021

- a one year exit clause in the previous contract; and
- ongoing uncertainty about the transmission pricing.

Energy Minister Megan Woods said … "We know we can't fully dispatch Manapouri generation out of the area without an upgrade to the grid. So what we have is the Clutha-Waitaki upgrade (which) has been approved by Transpower, about $100 million, that's already approved. It can be completed in three years."

Woods said the government was "actively looking to see" whether the work on the bottleneck in the grid could be brought forward even further using the recently legislated RMA fast track process.

Transmission Constraints

64. Currently the transmission grid has a significant constraint limiting the amount of electricity that can be transported from the lower South Island to where the greatest demand pressures are in the North.

65. If NZAS had closed based on the notice period, transmission constraints would have meant New Zealand businesses and consumers in other parts of the country would not have been able to benefit from large amounts of the additional supply freed up.

66. Furthermore, the closure would have resulted in the generation capacity in the lower South Island exceeding demand, forcing Meridian and Contact to spill water.

67. Contact has long recognised this constraint and the associated risk of spill in the event that NZAS stopped operating. We had been actively working with Transpower to address this constraint prior to the NZAS termination announcement.

68. In particular, the Clutha Upper Waitaki Lines project (CUWLP) was originally approved by the Electricity Commission in 2010. There were five sections to the CUWLP that involved the duplexing of four circuits and the thermal upgrade of another.

69. Prior to the announced closure of NZAS Transpower had indicated that they would not fund an acceleration of the CUWLP project, and that it would be unlikely to meet the target commissioning date of June 2022.[10] At the time Transpower indicated that "[f]or us to complete the project, we need sufficient certainty of the need to remove transmission constraints and allow excess generation in the region to be exported further north".[11]

70. In December 2019, Contact and Meridian each paid $5m to allow enabling works to commerce. Then in July 2020 Transpower advised that it would be continuing with the remainder of the CUWLP indicating that the work was likely to be completed by winter 2023.[12]

71. We also note that the completion of the CUWLP would not fully resolve practical transmission constraints to get supply north. Bottlenecks such as the HVDC would remain for example.

[10] https://contact.co.nz/aboutus/media-centre/2020/05/03/transpower-work-on-clutha-upper-waitaki-lines-delayed

[11] Transpower media release, *Transpower seeks input on Clutha Upper Waitaki Lines Project*, 7 May 2020.

[12] https://contact.co.nz/aboutus/media-centre/2020/06/30/update-on-clutha-upper-waitaki-lines-project

The threat of exit was very credible

72. At the time the review was announced, and through the negotiation period aluminium prices were at their lowest levels in the previous 10 years (figure [8]). This made the threat of NZAS exit very credible, giving NZAS a stronger negotiating position.

Figure [8]: Global price of Aluminium (USD per metric tonne, monthly average)[13]

73. Furthermore, at the time the review was announced, NZAS was ranked in the top quartile of global aluminium smelters by cost and was among the least competitive of Rio Tinto's aluminium smelters. This made the threat of exit particularly credible. Electricity and alumina are by far and away the largest individual cost items of aluminium smelting. With alumina being a globally traded commodity, electricity costs are typically the key cost variable between aluminium smelters. The size of this effect is shown in figure [9] and table 3.

74. In order to avoid the semi-regular but highly disruptive strategic reviews of NZAS, Rio Tinto wanted to shift NZAS's global competitiveness into the bottom half of global aluminium smelters by cost. To achieve this, a highly competitive electricity price was required.

[13] *International Monetary Fund, Global price of Aluminum [PALUMUSDM], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/PALUMUSDM, December 16, 2021*

Figure [9]: Ex-China aluminium smelter cash breakeven US$/t

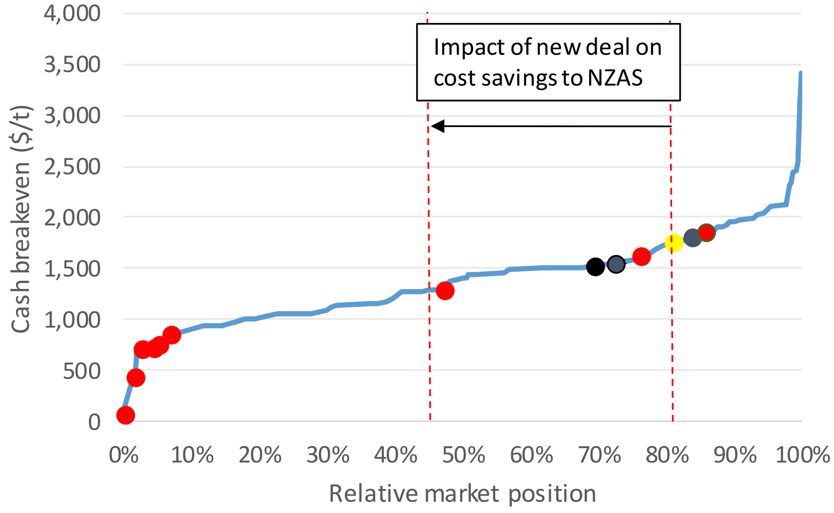


Table 3: Impact of cost savings to Tiwai's global ranking

NZ$ million pa	**Pre-deal**	**Post-deal**
	Percentile ranking	
Cash cost		
Tiwai	81%	44%
Bell Bay	84%	84%
Tomago	77%	78%
Boyne Island	73%	74%
Full operating cost		
Tiwai	81%	35%
Bell Bay	85%	85%
Tomago	56%	57%
Boyne Island	80%	81%
Energy		
Tiwai	58%	26%
Bell Bay	88%	88%
Tomago	53%	54%
Boyne Island	31%	32%
Cash breakeven		
Tiwai	81%	45%
Bell Bay	84%	84%
Tomago	73%	74%
Boyne Island	70%	71%

Source: Deutsche database from Woodmac

Cash cost = alumina + other raw materials + energy + labour + other costs

Full operating cost = cash cost plus depreciation

Energy = delivered electricity

Cash breakeven = revenue - cash cost

No alternative demand opportunities

75. At the time of the extension negotiations, there were few significant opportunities that would have been able to replace the load of NZAS. There are now significant new demand options in the pipeline including:

- Green Hydrogen – Contact and Meridian have been exploring the opportunities for the development of a large-scale green hydrogen facility in the lower South Island. In addition to a feasibility study, Southern Green Hydrogen called for expressions of interest from potential partners both domestically and internationally. Over 80 expressions of interest were received, and Southern Green Hydrogen have shortlisted a number of candidates and is undertaking more analysis with the shortlisted candidates with final proposals expected in mid-2022.
- Data centres – there is significant international interest in New Zealand's highly renewable generation to power data centres. Contact has recently signed an agreement to supply flexible renewable electricity for a new 10MW data centre

with Lake Parime near the Clyde Dam.[14] In the later stages of the negotiations, initial work had also begun on the viability of a $700m hyperscale data centre at Makarewa. This facility is now expected to be in service by 2023 and will use up to 100MW in its first stage. Extensions to this facility are a viable option when the NZAS contract expires in 2024.

- Electrification Projects – there is increasing focus around the electrification of process heat away from thermal fuels to electrification and biomass, with significant funding available from government including with the GIDI fund. This includes the replacement of gas and coal boilers to electricity.

> *The four-year deal will help protect jobs and incomes in Southland and provides a timeline for the Southland community to work alongside the Government to map out a clear transition plan for the region for the time the Tiwai smelter is shut down…*
>
> *Today's news is particularly welcome given the economic uncertainty created by the global COVID-19 pandemic.*
>
> The Minister of Finance commenting on the agreement to extend NZAS to December 2024[15]

One year exit clause in previous contract

76. The previous supply contract to NZAS provided electricity to Tiwai through to 2030. However, a termination clause within the contract allowed Rio Tinto to terminate the contract with 12 months-notice. Rio Tinto triggered this clause in July 2020, with operations to cease by August 2021.

77. This clause provided Rio Tinto with significant leverage in subsequent negotiations with its suppliers, the Southland community and the Government.

78. As a result the Government's 'Just Transitions' unit was deployed to help the Southland Community manage the closure.[16] There was wide-spread recognition that a 12-month termination would not be sufficient time for a managed transition.

Transmission Pricing Methodology – ongoing uncertainty

79. In assessing the economics of Tiwai, we expect that NZAS was considering the total cost of energy supply - which includes both the electricity cost as well as its direct connection to the grid.

[14] See: https://contact.co.nz/aboutus/media-centre/2021/08/30/contact-energy-to-supply-flexible-renewable-electricity

[15] Minister of Finance, Hon Grant Robertson, and Minister of Energy & Resources, Hon Dr Megan Woods joint media release, *Tiwai deal gives time for managed transition*, 14 January 2021

[16] https://www.mbie.govt.nz/business-and-employment/economic-development/just-transition/just-transitions-for-southland/

[Ministers] "recognised the fact that Rio [Tinto] exiting quickly would have pushed transmission costs on to other customers, which would have had a flow-through to New Zealand consumers".

Statement from the Minister of Energy and Resources.[17]

80. Rio Tinto has long argued that it pays a disproportionate share of Transpower's costs. In FY22, NZAS annual transmission costs are $58.3m. If NZAS was to exit Tiwai, these transmission costs would be reallocated across all other transmission customers – raising costs.

81. The new Transmission Pricing Methodology (TPM) will significantly reduce these costs for Tiwai,[18] however, at the time of the renewal it was not clear that these changes would go ahead. The government appears to have specifically considered whether to provide NZAS relief on transmission costs on the basis that the TPM would not have.[19] These changes are now expected to take effect from April 2023.

NERA show that there is a large degree of uncertainty regarding the Authority's conclusions

82. We commissioned NERA to review the Authority's analysis. They concluded that it is not clear if the Authority's propositions are true, and even if they are, the magnitudes are overstated. Nera's key findings are summarised below.

- **It is unlikely that the CFD price is below the opportunity cost of Meridian and Contact.** The Authority has materially over-estimated the price Meridian and Contact would have received under the exit scenario. NERA finds that the exit price would have been around $40/MWh, rather than the $70/MWh estimated by the Authority. This means other customers would not have paid significantly (or any) more than the price paid by NZAS, largely eliminating the allocative efficiency concerns.
- **The uncertainty regarding grid upgrades is not accounted for** at the time of negotiating the CFD the timing of the CUWLP upgrade was **unclear**. Contact and Meridian would have assumed some probability that more water was stranded for longer than assumed by the Authority
- **The cost of lost option value was not counted** once NZAS exits they would have been lost as a customer forever, whereas if they were **persuaded** to stay then there is a probability that a deal could be negotiated in the future that is more favourable to Meridian and Contact. Given the volatility of the aluminium

[17] https://www.nzherald.co.nz/business/government-was-preparing-to-directly-subsidise-rio-tintos-transmission-costs/BLB4C4IVMH5GILK4Y7Z6K3SVOE/

[18] Based on the Electricity Authority's near final draft decision, NZAS annual transmission cost would reduce to $44.3m. They may also be able to apply for a prudent discount which may bring charges down to $20m per year.

[19]New Zealand Herald, *Government was preparing to directly subsidise Rio Tinto's transmission costs*, 17 April 2021: https://www.nzherald.co.nz/business/government-was-preparing-to-directly-subsidise-rio-tintos-transmission-costs/BLB4C4IVMH5GILK4Y7Z6K3SVOE/

market, and the low price at the time of the deal, it is likely that this option value would have been material.

- **Value of increased certainty of a four-year contract is not considered** the new contract effectively bought out the option in the previous contract to exit with one year's notice.
- **The offsetting profits are unclear** NERA question the $90/MWh price under the stay scenario. The also highlight that there were a variety of other factors **affecting** prices across the relevant time period, such as the gas supply issue highlighted in this submission.
- **The willingness to pay for NZAS is constantly changing and may often be sufficiently high for there to be no allocative efficiency problem** The allocative efficiency problem supposed by the Authority relies on the willingness to pay of NZAS being materially below the price paid by the rest of New Zealand P^{STAY}, such that another user would have a more valuable use for the electricity. However, as the Authority notes, NZAS' willingness to pay is not easily known, and it is likely very volatile in line with the price of aluminium. Enerlytica has estimated the October 2021 NZAS EBITDA breakeven power price to be $158/MWh. A breakeven power price at this sort of level would suggest the willingness-to-pay of NZAS would likely be above the Authority's assumed value for PSTAY ($90/MWh) and there would be no allocative inefficiency from the CFD.
- **The Authority should have applied a discount rate** It is very unusual for any financial **analysis** to assume a discount rate of zero, even when interest rates are very close to zero. Applying an appropriate discount rate would materially reduce the size of the issue found by the Authority.
- **The NZAS contract is unique** similar to our argument above, NERA **also** observes that the NZAS contract has features that mean any conclusions cannot be generalised to the wider market.
- **The NZAS contract can help improve dynamic efficiency** by improving security of supply via an incentive to **retain** flexible thermal plant, and NZAS demand-side response capability.

83. Putting this analysis together shows that neither the allocative inefficiency nor the benefits to Meridian and Contact are as clear cut as suggested by the Authority. The uncertainty on all these metrics was well known when the NZAS contract was negotiated, which did not provide the basis for the theoretical loophole identified by the Authority to even be considered.

A case has not been made for intervention

84. The Authority has not sufficiently made the case for any intervention. The issue identified by the Authority may have some theoretical validity, however, there are many unmeasured factors that together mean generators could not manipulate the market in the way envisioned.

85. The Authority must therefore choose the status quo as the only reasonable option.

86. NERA's paper considers the other options but finds that none are proportionate to the problem. Contact Energy therefore recommend that this investigation is closed.

NERA
ECONOMIC CONSULTING

Review of Electricity Authority's "Inefficient Price Discrimination" Discussion Paper

Contact Energy

21 December 2021

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[1] With comments provided by George Anstey.

CONFIDENTIALITY

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Contents

1. Introduction and executive summary

1. On 27 October 2021, the Electricity Authority released a discussion paper titled, "Inefficient price discrimination in the wholesale electricity market – issues and options" (**"the Discussion Paper"**). The Discussion Paper posits that the contract-for-difference (**"CFD"**) entered into between Meridian and NZAS, and the supporting CFD entered into by Contact and Meridian, resulted in "inefficient price discrimination".
2. We have been asked by Contact to review:
   A. The Authority's problem definition (section 2); and
   B. The policy options canvassed by the Authority (section 3).
3. A summary of our views is as follows:
   A. While it might be conceptually possible to have inefficient price discrimination in the wholesale electricity market, the evidence is not sufficient to make such a finding in respect of the Meridian and Contact CFDs:
      i. It seems quite likely that the price under the CFDs was above or at least similar to the opportunity cost of Meridian and Contact. This is particularly the case when the option value to society, Meridian and Contact in retaining NZAS as a load customer is taken into account; and
      ii. The value placed on the electricity by NZAS rose significantly after entering into the CFDs. For example, in a 21 October 2021 report Enerlytica states, "Our EBITDA breakeven power price [for NZAS] rises a further +$8/MWh to $158/MWh", which suggests a higher valuation than the market price assumed by the Authority under its "stay" scenario.[2]
   B. Accordingly, there is no justification for any of the Authority's posited reform options, except for continuation of the status quo.
   C. Even if a problem was identified, it would be:
      i. A function of the extreme size of the relevant load (NZAS' in this case), and therefore the potentially large effect on the market price; and
      ii. Complicated by the difficulty in knowing whether the relevant large customer has a lower willingness-to-pay than the (ostensibly) crowded out customers.
   D. This would suggest that any reform should:
      i. Be targeted at very large contracts; and
      ii. Rely on the market to identify any inefficiency.

[2] Enerlytica "Tiwai-ometer", 21 October 2021.

2. Problem definition

2.1. Conceptual problem definition

4. The Authority's analysis, as illustrated in Appendix B to the Discussion Paper, is stylistic - it assumes a single node, a single generating firm (with multiple generation plants), and does not take into account hedge and retail positions.

5. Nevertheless, the problem identified by the Authority is conceptually plausible. Unlike in many other types of markets where offering a low price to a low willingness-to-pay customer can expand total output, the specifics of the wholesale electricity market can lead to less efficient results.

6. Consider, for example, a movie theatre, which can increase demand from students by offering them a discounted price without raising the standard adult price. In contrast, adding demand to the electricity market has the potential to raise price for the "inframarginal" customers if higher cost plant needs to be dispatched to meet the greater demand.

7. As the Authority's analysis illustrates,[3] whether there is an efficiency problem depends critically on what the willingness-to-pay for electricity of NZAS is. That willingness-to-pay is likely to:

   A. Vary markedly over time, as we discuss in this report; and

   B. Require estimation by counterparties and the Authority, which is unlikely to be precise.

8. Furthermore, if there is an efficiency problem, the materiality of that problem is a function of the size of the demand served by the hedge contract. The larger that demand:

   A. The more likely it is that the spot price (P^{STAY} in the Discussion Paper's parlance) would be set by a higher cost generation plant; and

   B. The higher any producer efficiency loss would be.

9. Therefore, the problem the Authority is concerned with is fundamentally about very large customers with low willingness-to-pay. We return to these points later in our report.

2.2. Profitability to Meridian and Contact

10. The Authority's theory of harm rests on the propositions that:

    A. The CFD price was lower than Meridian's (and Contact's) opportunity cost for the relevant volume of electricity; and

    B. The consequent loss on the CFD volume was more than offset by profits on Meridian's (Contact's) other volumes.

11. We review the relevant evidence below and conclude that it seems likely the price under the CFDs was above or at least similar to the opportunity cost of Meridian and Contact. Accordingly, it is quite possible that the CFD was profitable to Meridian (Contact) regardless of any effect on profits on Meridian's (Contact's) other volumes. This would imply that the behaviour was consistent with that observed in competitive markets.

12. Therefore, the Authority's propositions do not appear to be made out. Even if they were, their magnitudes are overstated by the Authority.

[3] For example, compare Figures 7 to 9 with Figures 10 to 13.

2.2.1. Opportunity cost of Meridian (and Contact)

13. For the accumulation of the following reasons, it seems unlikely that the CFD price (which is between \$30/MWh and \$40/MWh)[4] is below the opportunity cost of Meridian and Contact.

2.2.1.1. The Authority has overestimated the price Meridian and Contact would have received under the exit scenario

14. Subject to a calculation to account for a grid constraint (discussed in section 2.2.1.2 below), the Authority's analysis assumes that Meridian and Contact could have sold the CFD quantities of electricity under the exit scenario for the futures price at Benmore. Possibly because its framework is based on a single node, the Authority appears to equate the opportunity cost of Meridian and Contact to its variable P^{EXIT}.

15. In the Authority's base case, P^{EXIT} is assumed to be \$70/MWh ([5.19]):

> *…average price under exit scenario = \$70/MWh (in line with Benmore futures after NZAS exit was announced 9 July 2020, with an adjustment to approximate an average, whole-of-New Zealand price)…*

16. It is not clear from the Discussion Paper what "adjustment to approximate an average, whole-of-New Zealand price" the Authority made. We interpret this to mean that P^{EXIT} is not the price Contact and Meridian would have received for the generation relevant to the CFD (i.e., their opportunity cost), but instead is an estimate of the national average price all generators would receive in the exit scenario.

17. Subject to the Authority's adjustment not being explained, it seems wrong to use \$70/MWh for P^{EXIT}. Eyeballing the Authority's own Figure 6, when NZAS announced its exit on 9 July 2020, the Benmore futures price dropped to something closer to \$50/MWh. And checking against ASX data supplied to us by Contact, the:

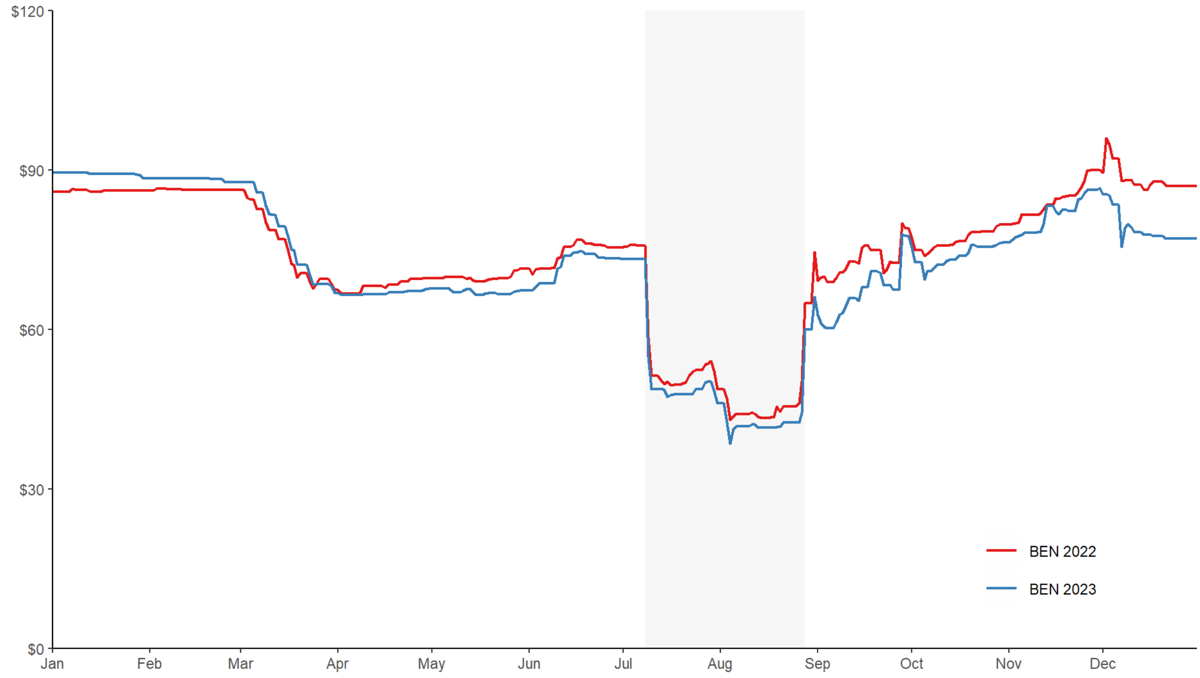
    A. 2022 Benmore futures price dropped from \$75.80/MWh on 8 July 2020 to \$58.58/MWh on 9 July 2020; and

    B. 2023 Benmore futures price dropped from \$73.28/MWh on 8 July 2020 to \$54.94/MWh on 9 July 2020.

18. See more generally Figure 1 below (where the shaded area identifies the 9 July 2020 to 28 August 2020 period).

[4] According to page iv of the Authority's parallel "Market Monitoring Review" Information Paper.

Figure 1: Benmore futures prices over 2020 ($ per MWh)



Source: ASX data (https://asxenergy.com.au/) provided by Contact.

19. Furthermore, it is likely that the futures price on 9 July 2020 reflected some probability that NZAS would not actually exit. Interestingly, the futures price continued to drop in the weeks after 9 July 2020, to a low on 4 August 2020 of:

    A. $43/MWh for 2022; and

    B. $38.50MWh for 2023.

20. Figure 6 of the Discussion Paper notes that "Ministers state they are unconvinced smelter is viable" on 4 August. It is possible that these 4 August 2020 prices reflect a more accurate expectation of an exit price.

21. Finally, the opportunity cost to Meridian and Contact would have been the price at the nodes they sell the relevant electricity at, which in Contact's case are Roxburgh and Clyde, not Benmore.[5] Also, the CFD with NZAS is referenced at the Tiwai node.

22. The price received at the Roxburgh and Clyde nodes, relative to the Benmore price, will be a function of losses and congestion between those nodes and the Benmore node. Because power generally flows from south to north, these prices will generally be below the Benmore price.

23. Financial transmission right (**"FTR"**) auction data suggests the price at Invercargill is typically about $2/MWh less than that at Benmore.[6] This difference increased to between approximately $9-12/MWh in the July 2020 – January 2021 period (presumably reflecting an expectation of

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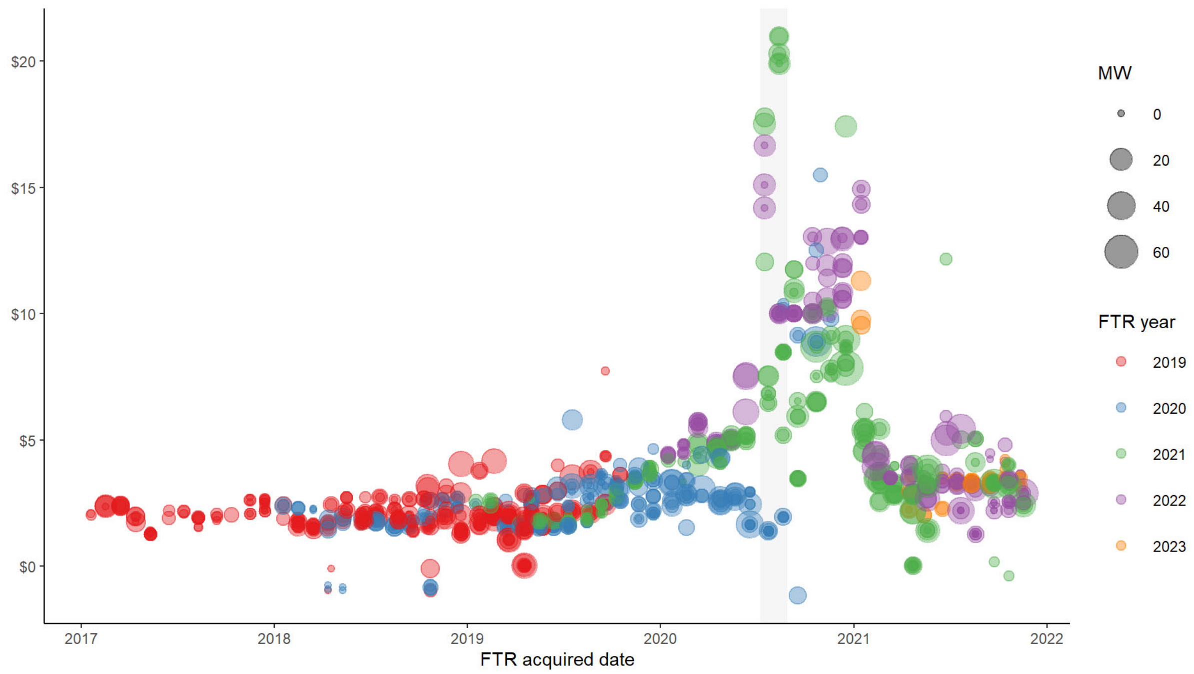
[5] We presume the Authority chose to analyse Benmore because there is ASX pricing at that node, but not at nodes further south.

[6] FTRs pay out the difference in price between nodes, and thus FTR prices provide a market forecast of the expected price differential between the two nodes in the FTR contract.

greater flows to Benmore and therefore increased losses and also increased congestion),[7] before decreasing to approximately $3/MWh. See Figure 2.

Figure 2: Invercargill-Benmore FTR auction clearing prices by volume and FTR start year ($ per MW)



Source: INV-BEN FTR option auction clearing prices data (https://www.ftr.co.nz/) provided by Contact.

24. There are not any FTRs between Roxburgh or Clyde and Benmore. However, we understand from Contact that the Invercargill, Roxburgh and Clyde nodes are electrically very close. Accordingly, the Invercargill-Benmore FTR price probably provides a proxy for the difference between prices at Roxburgh or Clyde and Benmore.

25. Accordingly, it seems likely that the price Meridian and Contact could have sold the electricity for if NZAS exited is somewhere in the $40/MWh range[8] and possibly even lower.[9]

2.2.1.2. The Authority has not recognised uncertainty regarding grid upgrades

26. It is important to note that the Tiwai smelter and the relevant generation assets supporting the CFD are south of the Clutha Upper Waitaki grid constraint, i.e., "behind the constraint". Therefore, some of the CFD quantity would have had an opportunity cost of zero under the exit scenario, as the water would have been spilt. This means the average opportunity cost of the CFD would be (potentially significantly) less than the price discussed in section 2.2.1.1 of this report.

27. The Authority's modelling does account for this to some degree, not through reducing the expected exit price, but by reducing the assumed quantity ("Q^{AS}") in 2022. In its base case, the

[7] The electrical losses on a circuit increase according to a non-linear function. This means that the higher the line flows, the relatively higher the losses. The temporary increase in FTR prices that occurred reflected the expectation of relatively higher line losses if the smelter were to exit, as well as an expectation of increased congestion.

[8] Being $58.58/MWh less $9-12/MWh and $54.94/MWh less $9-12/MWh.

[9] Lower if we use the 4 August 2020 Benmore prices as the starting point from which to subtract FTR prices.

Authority assumes that 140MW of water would have been stranded in 2022.[10] However, this accounting is deterministic. We understand from Contact that at the time of negotiating the CFD, the timing of the grid upgrade was unclear. On this basis Meridian and Contact would have assigned some probability to that 140MW of water being stranded beyond 2022.

2.2.1.3. The opportunity cost of Meridian and Contact would have been further reduced by lost option value

28. As the Authority acknowledges, the willingness-to-pay of NZAS will vary over time, e.g., as the price of aluminium varies. This means there is option value to society, Meridian and Contact in retaining NZAS as a load customer:

    A. If Meridian/Contact did not enter into the CFD, NZAS would have been lost as a load customer forever.

    B. Whereas if NZAS is persuaded to stay, there is a probability that:

        i. Meridian and Contact could sell electricity to NZAS at a higher price in the future (particularly given Meridian and Contact produce green electricity, which is likely be of value to NZAS);[11] and

        ii. NZAS could offer valuable flexibility to the market as New Zealand transitions to 100% renewables. Recent analysis by Concept Consulting finds that aluminium smelter demand response would be a relatively low-cost option for achieving broader economy-wide decarbonisation.[12]

29. Regarding the option value to Contact/Meridian of selling electricity to NZAS at a higher price in the future, aluminium prices are volatile and were at a relatively low level at the time of the CFD, as depicted in Figure 3 below (with the grey bar designating the period between the NZAS exit announcement on 9 July 2020 and the confirmation of ongoing negotiations with NZAS on the 28th August 2020). Option theory suggests that the value of an option is greater when volatility is higher. Therefore, the option of being able to sell to NZAS in the future would likely be particularly valuable to Contact/Meridian.

[10] [5.19].

[11] See the Rio Tinto presentation at https://www.riotinto.com/-/media/Content/Documents/Invest/Presentations/2021/RT-Investor-Seminar-2021-slides.pdf?rev=79cfcc69970d493e8cd62aa4b5877b06, which refers to Rio Tinto's desire to use more renewable energy.

[12] Concept Consulting (2021) "Potential benefits from large-scale flexible hydrogen production in New Zealand", report prepared for Meridian and Contact, 31 August.

Figure 3: Global price of aluminium (USD per metric ton, monthly average, 1990-2021)

Source: International Monetary Fund, Global price of Aluminum [PALUMUSDM], retrieved from FRED, Federal Reserve Bank of St. Louis; https://fred.stlouisfed.org/series/PALUMUSDM, December 12, 2021.

30. Indeed, as the graph shows, aluminium prices recovered substantially following the signing of the CFD and are now nearing historic highs. This is reflected in the following 21 October 2021 statement by Enerlytica: "Our EBITDA breakeven power price [for NZAS] rises a further +$8/MWh to $158/MWh".[13]

31. At page iv of the Discussion Paper, the Authority states:

> *The strong improvement in NZAS's profitability that has occurred after the offers were made and contracts signed, due to changes in aluminium prices, which are known with hindsight, is not directly relevant for the efficiency of the price discrimination negotiated in the current contracts.*

32. This statement (which is about hindsight) ignores that the current four-year contract should be viewed as part of a broader ongoing relationship between NZAS and Contact/Meridian.

33. If Meridian and Contact had not entered into the CFDs, the option value discussed here would have been extinguished. Accordingly, that lost value should be considered when analysing the opportunity cost to Meridian and Contact – it would have the effect of lowering the opportunity cost.

2.2.1.4. Other reasons for discounts

34. The Discussion Paper states ([4.4(c)]):

> *the Tiwai contract also corresponds to an unusually large amount of electricity, which might be expected to receive a cost-based discount, just as generic wholesale prices differ from retail prices*

35. We agree with this statement. Furthermore, we understand that the CFDs provided Meridian and Contact with more certainty than the existing NZAS contract. The existing contract could have lasted until 2030, but NZAS had the option to terminate on a year's notice. The new CFDs effectively bought out this option and commit NZAS to a fixed period of 4 years.

[13] Enerlytica "Tiwai-ometer", 21 October 2021.

2.2.2. Offsetting profits

36. In its baseline modelling, the Authority uses a price of $90/MWh for the variable P^{STAY}, on the basis of $90/MWh being *"in line with Benmore futures prices after ongoing negotiations were confirmed by NZAS 28 August 2020 and estimates of the levelised cost of electricity"* ([5.19]).
37. It is not clear from the Discussion Paper what adjustments the Authority has made to reflect the *"levelised cost of electricity"*, but subject to this, the $90/MWh seems odd. According to the ASX data provided to us by Contact, on 28 August 2020 the Benmore futures price was $65/MWh (2022) and $60/MWh (2023).
38. More generally, the second panel of the Discussion Paper's Figure 6 implies that there were a variety of factors affecting prices across the relevant time period. For example, as the Authority's parallel paper describes, uncertainty about future gas supply and low hydro storage may have been affecting electricity prices.[14] It is also likely that some probability of Tiwai exit was still being priced in.
39. It is also interesting that Benmore futures, after steadily increasing in late 2020, fell at the start of December, then plateaued before jumping up on 14 January 2021 with the announcement of the new NZAS contract.
40. These various complexities suggest that we need to be cautious about placing too much weight on the various prices for the purposes of the efficiency and transfer analysis.
41. Furthermore, whatever the relevant futures price was, that price overstates the benefits that Meridian and Contact would receive through the effect of P^{STAY} on their non-NZAS output. This is because Meridian and Contact also have retail books, and probably other hedges, which offset the benefit of a higher wholesale spot price.[15]

2.3. Materiality of inefficiency in relation to Tiwai contract

2.3.1. It is unclear if there is any allocative inefficiency

42. The Authority's quantitative estimate of allocative inefficiency is a function of:
    A. The difference between P^{STAY} and P^{EXIT}; and
    B. The elasticity of the "RoNZ" demand curve.
43. As discussed above, we question the values used by the Authority for both variables P^{STAY} ($90/MWh) and P^{EXIT} ($70/MWh). If we use the same dates the Authority does and the ASX data provided to us by Contact, then the gap would be $10/MWh or less, based on:
    A. Futures prices between $55/MWh and $59/MWh on 9 July 2020; and
    B. Futures price between $60/MWh and $65/MWh on 28 August 2020.
44. If instead we use the drop in futures prices when NZAS made its exit announcement on 9 July 2020, the difference would be closer to (although still less than) $20/MWh, which is the number used in the Authority's baseline calculation (i.e., the difference between $70/MWh and $90/MWh).
45. More fundamentally the existence and quantum of allocative inefficiency is a function of the willingness-to-pay for electricity of NZAS. The willingness-to-pay of NZAS is actually unknown, as the Authority notes at [5.5] of the Discussion Paper. Furthermore, the willingness-

[14] Electricity Authority "Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market Since the Pohokura Outage in 2018", Information Paper, released 27 October 2021.

[15] The potential for pass-through to be incomplete was noted by the Authority at [5.13] of the Discussion Paper.

to-pay of NZAS for electricity is likely to vary materially over time, as the price of aluminium changes (see Figure above).[16]

46. As noted in section 2.2.1.3, Enerlytica has estimated the October 2021 NZAS EBITDA breakeven power price to be $158/MWh. A breakeven power price at this sort of level would suggest the willingness-to-pay of NZAS would be above the Authority's assumed value for P^{STAY} ($90/MWh) and there would be no allocative inefficiency from the CFD (the situation would be depicted by Figures 7 to 9 of Appendix B rather that Figures 10 to 13).

47. As already noted, at page iv the Authority states:

The strong improvement in NZAS's profitability that has occurred after the offers were made and contracts signed, due to changes in aluminium prices, which are known with hindsight, is not directly relevant for the efficiency of the price discrimination negotiated in the current contracts.

48. We have already discussed why we think this statement ignores important option value. Furthermore, whether an allocation of electricity is efficient does not depend on the terms of a contract – it depends on whether electricity is being consumed by those who value it highest at the actual time.

2.3.2. The Authority has overestimated the size of the producer efficiency loss (if there is any)

49. The Authority's estimate of the producer efficiency loss is a function of (among other things):

    A. The difference between P^{STAY} and P^{NEG}; and

    B. The difference between P^{EXIT} and P^{NEG}.

50. For the reasons discussed above, the Authority appears to have materially overstated P^{EXIT} and P^{STAY}. Accordingly, the Authority has materially overstated the producer efficiency loss. Furthermore, as discussed in section 2.2.1, it seems quite likely that the price under the CFDs was above or at least similar to the opportunity cost of Meridian and Contact.

51. On the Authority's modelling, the producer efficiency loss is also reduced by the welfare gain to NZAS, which is a function of the difference between P^{WTP} and P^{NEG}. Therefore, as P^{WTP} increases with the price of aluminium (all else being equal), the producer efficiency loss will reduce.

52. Indeed, the whole conceptual basis of the Authority's concern depends on the difficult-to-identify willingness-to-pay of NZAS for electricity. As per Figures 7 to 9 of the paper, the concern would drop away if the willingness-to-pay of NZAS was sufficiently high.

2.3.3. The Authority has overestimated the size of the transfer

53. For the reasons discussed above, the Authority appears to have overstated the gap between P^{EXIT} and P^{STAY}. Accordingly, the Authority has overstated the transfer.

54. Of course, how any transfer is characterised depends on the perspective. The Discussion Paper treats P^{EXIT} as the starting point of the analysis, and so characterises a shift to P^{STAY} as a transfer to generators from consumers. However, NZAS has drawn significant load from the New Zealand electricity sector for many years. Accordingly, we could treat P^{STAY} as the starting point, and instead of interpreting consumers as suffering from a transfer, interpret them as missing out on lower prices, if NZAS stays.

2.3.4. Discount rate

55. The Authority also fails to use a discount rate, on the basis that ([5.16] of the Discussion Paper):

[16] Input cost changes could also affect the willingness of NZAS to pay for electricity.

Given that interest rates are very close to zero, present discounted values for Y years would be approximately Y times the annual dollar amounts reported here.

56. However, this analysis is incorrect – the discount rate for this type of analysis is a function of more than just the interest rate. Even taking into account a risk-free rate of 0.65% as at 26 May 2020, the Treasury's current advice is to use a default (real, pre-tax) discount rate of 5%.[17]

2.4. Idiosyncratic nature of the Tiwai situation

57. In considering the costs and benefits of the reform options put forward by the Authority (which we do in section 3 below), it is important to recognise the uniqueness of the Tiwai situation:

    A. The materiality of NZAS (no other customer comes even close). As the Authority states ([4.11] of the Discussion Paper):

    At 13 percent of generation, the load from NZAS is twice the size of load from other industrial grid-connected consumers combined, such as the Norske Skog pulp and paper mill at Kawerau and the New Zealand Steel mill at Glenbrook;

    B. The variability of the willingness-to-pay for electricity of NZAS, as discussed in section 2.2.1.3 above;

    C. The physical location of NZAS (bottom of the South Island, proximate to Manapouri (which was built to meet the smelter's demand), whereas most electricity demand is much further north); and

    D. The temporary transmission constraint north of Clutha. Once the constraint is relieved, the opportunity cost to Meridian/Contact of the CFD would be higher. Also, NZAS would have less bargaining power over Meridian/Contact.

58. As the Authority says itself ([3.2]):

    The Tiwai contracts seem to provide preferential pricing in a way that is unique in the industry, even in contrast to the terms available to other large industrial consumers.

2.5. Dynamic efficiency effects

59. In Table 1 of the Discussion Paper, the Authority states:

    Dynamic efficiency and the transition to a low emissions economy

    Prices provide incentives for innovation and investment in generation, electric vehicles, the electrification of process heat, investment in industrial processes, and investment in technologies to shift electrical load through time. If prices are distorted by inefficient price discrimination then investment in all forms of capital may be distorted, posing a risk to New Zealand's transition to a low emissions economy.

60. We agree there is a risk that inefficient price discrimination could distort prices and investment. However, there is also another perspective on this issue.

61. As New Zealand moves towards its goal of 100% renewable generation, security of supply will be increasingly challenging as new renewables enter the market and utilisation of thermal plants falls. New Zealand's hydro generation is subject to dry year risk, and wind generation is intermittent.

62. This security of supply could come from thermal generation and/or demand response.

[17] See https://www.treasury.govt.nz/information-and-services/state-sector-leadership/guidance/financial-reporting-policies-and-guidance/discount-rates.

63. There is also a public good characteristic to security of supply, potentially leading to under-supply. For example, Abbott states (32-33):[18]

In the case of electricity generation, any expansion in capacity designed to meet growth in demand not only reduces the risk of blackouts for those being supplied from the new plant but also reduces everyone else's risk at no extra cost. This means that security is nonrival in public good terms. Security of supply also appears to be nonexclusive in that it is difficult to exclude people from benefitting from that reduced risk associated with the construction of additional capacity given the physical nature of electricity and the manner in which it is supplied to consumers across a jointly used network.

In these circumstances, it is possible that in a competitive market that there will be an underinvestment in new generation capacity because the owners of new capacity will not be able to capture its full value to consumers. This means that generators may possibly maintain slimmer reserve capacity margins then [sic] consumers demand. If that is the case, there may then be justification for the government or the system operator to raise revenue through general taxes or a levy on supply and use it to guarantee supply through the subsidization of new capacity or, alternatively, demand-management programs.

64. So while the Authority rightly points out the dynamic efficiency effects of a higher wholesale market price caused by NZAS remaining in the market, there would also be dynamic efficiency effects from a lower wholesale price caused by the exit of NZAS. In particular:

    A. North Island thermal plants would be more likely to exit; and

    B. NZAS would not be available to provide demand-side response.

65. As well as reducing security of supply, exit by North Island thermal plants at the same time as demand for instantaneous reserves increases (due to higher flows across the HVDC) could lead to higher reserve prices and/or increased hydro spill.

66. Without further analysis, it is not clear which effects would be "worse". Our main point is that the Authority needs to ensure there is a comprehensive and balanced analysis, across all potentially affected components of the electricity system (which is broader than just the spot market).

[18] Malcolm Abbott (2001) "Is the Security of Electricity Supply a Public Good?" *The Electricity Journal*, August/September, 31-33.

3. Analysis of proposed options

67. The Authority canvasses eight policy options to address the posited inefficient price discrimination.

68. To reiterate, the essential problem identified by the Authority is that the willingness-to-pay of an idiosyncratically large customer (NZAS) may be lower than the willingness-to-pay of certain other consumers that are priced out of the market. The problem is a function of:

   A. The extreme size (of NZAS in this case), and therefore the potentially large effect on the market price; and

   B. The difficulty in knowing whether that large customer has a lower willingness-to-pay than the negatively affected customers.

69. We therefore assess the options proposed by the Authority against these factors. Our assessment is set out in Table 1.[19]

Table 1: Assessment of reform options

Option	NERA comment
Status quo	In section 2 of this report, we have questioned whether the Authority has identified a problem and if it has, whether that problem is material. If there is not a material, defined problem, then the status quo is the appropriate option. If there is in fact a material, defined problem, then the solution should be more targeted at the problem than any of the other options outlined in the Discussion Paper are. We discuss this further below in this table.
Prohibit 'use-it-or-lose-it' clauses	If this option was to be applied, it should be limited to very large contracts that have the ability to materially affect the market price. However, we understand there would be little point in prohibiting use-it-or-lose-it rules, because parties could use "physical" contracts instead, which have the same effect, i.e., customers can only take what they use themselves. We understand from Contact that the majority of large commercial and industrial customers have this type of physical contract, known as a fixed price variable volume (FPVV) contract. Whether in the form of "physical" contracts or use-it-or-lose-it clauses, there are legitimate, commercial rationales for these mechanisms. For example, if a buyer closes down or reduces load, the supplier would have the option of finding alternative demand for the electricity. The supplier would also have control over the nature of the buyer, e.g., its credit worthiness.
Electricity Authority pre-approval of large contracts	Because of information asymmetries, the Authority would find it very difficult to judge the efficiency of contracts. The prospect of having to seek approval would also chill commercial decision-making. This sort of intervention would be unsettling for investors in generation and load, and may raise the cost of capital. The Authority gives as precedents the Overseas Investment Office regarding purchases of assets by foreigners, and Commerce Commission approvals of mergers. However, these types of transactions are likely to be rarer than the entering into of (large)

[19] We have not been asked to review the "other options that could be considered" set out in [6.61-6.73] of the Discussion Paper.

	electricity contracts[20] and the processes are very time and resource intensive. They are also processes widely adopted in other countries, and so are expected by investors. It is not clear to us that the same could be said for regulatory approval of electricity contracts.
Require public offering of all (or some percentage of) hedge contracts	This option could address an important difficulty of the preceding option, being the Authority needing to judge contract efficiency. Contract efficiency is best tested and judged by the market, rather than the Authority. However, as described by the Authority, the proposal is unnecessarily broad. For example, at [6.28] the Authority states: *"Under this option, all (or at least a significant) portion of each generator's portfolio of electricity hedges, both for the energy and location component, would need to be offered and bid for publicly."* If the Authority has identified a problem in its paper, that problem is a function of contract size. Accordingly, that problem could be addressed by just requiring particularly large contracts to be auctioned. For example, if Meridian or Contact negotiated a 500MW CFD with a new hydrogen plant in Southland, there could be a relatively short period of time in which that contract could be bid for by others (with the hydrogen plant having the right to bid too). This sort of mechanism should be used sparingly (i.e., just for contracts at the very extreme end of the size distribution), because it may chill investment by load – why go to the effort of negotiating a contract if another party can then swoop in and (potentially) buy the rights under it? This could be partly addressed by tweaking the ordering to require this notification at the outset of negotiations, such that negotiations with other parties would occur in parallel. This has parallels with the "Open Season" process that occurs for new gas pipeline capacity in the United States. However, this option would also suffer from the issue that large loads may not wish to have their intentions to enter certain markets known prior to having all their supply agreements in place.
Require public offering of large hedge contracts	See our comments in respect of the preceding option.
Extend trading conduct provisions beyond the spot market to hedge markets	It might be very difficult for the Authority to assess whether a hedge contract is consistent with what would be offered under competitive circumstances – we could expect a lot of controversy under this option.
Non-discriminatory pricing rules	The dividing line between what is unjustifiably and justifiably discriminatory can be very difficult to judge. This would be the case even if there was just a single type of hedge, but the fact there are a variety (e.g., retail customers, FTRs, PPAs, options, futures, etc) makes it even more difficult. Locations, lengths, quantities and demand response will also differ. We think it is better to test efficiency through a market mechanism, as discussed above in this table. At [6.57] the Authority refers to other "non-discriminatory pricing regimes". It is not clear which regimes the Authority is referring to, but it may be regimes where vertically integrated monopolists offer access to downstream rivals. For the reasons already discussed, it is likely that contracts in the wholesale electricity market will be more complex and dynamic.

[20] Although we acknowledge this does depend on how a "large contract" is defined.

Hybrid of non-discriminatory pricing and pre-approval of contracts	For the reasons already discussed, we do not think this is an appropriate option.

70. We also note that there are several references in the Discussion Paper to certain options addressing concerns about gentailers favouring their own retail arms. For example ([6.32]):

Requiring less than 100 percent of future contracts to be traded publicly could reduce these costs, while still providing greater confidence that inefficient discriminatory pricing is not occurring or not substantially impeding competition. For example, requiring the sale of a sizeable portion of electricity on public markets may provide added assurance that generator–retailers are not unduly favouring their internal retail arms relative to large consumers and on-sellers, including independent retailers, especially where the internal retail arms are required to buy a significant portion of their electricity on public markets.

71. We note that the Discussion Paper does not identify or analyse whether there is a vertical integration problem. Accordingly, it is not appropriate to assess the efficacy of an option on the basis of a vertical integration theory of harm.[21]

[21] We are also advised by Contact that as a market maker it makes prices to sell ~220GWh of ASX contracts every day. Contact's internal transfer price is based on this market price.

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