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Draft Determination

Note: This is a Draft Determination issued for the purpose of advancing the Commerce Commission's decision on this matter. The conclusions reached in this Draft Determination are preliminary and take into account only the information provided to the Commission to date.

This is a Draft Determination under the Commerce Act 1986 in the matter of an application for authorisation of a restrictive trade practice. The application is made by:

Genesis Energy Limited, Contact Energy Limited, Meridian Energy Limited and Mercury NZ Limited between Genesis, Contact, Meridian and Mercury

The Commission:	John Small Anne Callinan Nathan Strong
Summary of application:	Genesis Energy Limited, Contact Energy Limited, Meridian Energy Limited, and Mercury NZ Limited have applied for authorisation to enter into and give effect to the Strategic Energy Reserve Huntly Firming Option to access certain notional generation capacity from Genesis' Rankine Units at the Huntly Power Station.
Determination:	The Commerce Commission's draft decision is to grant authorisation as it is satisfied that the Proposed Arrangements will in all the circumstances result, or be likely to result, in such a benefit to the public that the conduct should be permitted.
Date of Draft Determination:	29 September 2025

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Acronyms and abbreviations

2degrees	2degrees Limited
Act	Commerce Act 1986
Additional Baseload Capacity	Each Counterparty will have an additional 25 MW of Additional Baseload Capacity available in certain circumstances.
Applicants	Genesis, Contact, Meridian and Mercury
Application	Application for authorisation submitted to the Commerce Commission from the Applicants
ASX	Australian Securities Exchange
ASX Hedges	Hedges traded on the Australian Securities Exchange
Baseload Hedges	See paragraph 76.2
BESS	Battery energy storage system
Cartel Authorisation Sections	Sections 58(6B) and (6D) of the Act
CFDs	Contracts for difference
Clearing Manager	The clearing manager ensures that industry participants pay or are paid the correct amount for the electricity they generate, or consume, and for market-related costs.
Code	Electricity Industry Participation Code 2010
Commission	Commerce Commission
Competition Authorisation Sections	Sections 58(1)-(2) of the Act
Contact	Contact Energy Limited
Core Capacity	The Core Capacity is 50 MW per Counterparty, as may be subsequently adjusted for suspension events pursuant to the Proposed Arrangements.
Counterparties	Mercury, Meridian and Contact
EA	Electricity Authority
Electric Kiwi	Electric Kiwi Limited

emhTrade	emhTrade Markets Limited
ERCs	Electricity risk curves
ETS	Emissions Trading Scheme
EV	Electric vehicle
Fletcher Building	Fletcher Building Limited
Framework Agreement	One of the contracts making up the Proposed Arrangements. See paragraph 43.3
Genesis	Genesis Energy Limited
Gentailers	'Generator-retailers': Genesis, Contact, Meridian and Mercury
GW	Gigawatt
GPS	Government Policy Statement
Haast Energy	Haast Energy Trading Limited
HFOs	Huntly Firming Options
HSER HFO	Huntly Strategic Energy Reserve Huntly Firming Option
IEGA	Independent Electricity Generators Association
ISDA	International Swaps and Derivatives Association
kt	Kilotons
Lodestone Energy	Lodestone Energy Limited
MBIE	Ministry of Business, Innovation and Employment
Mercuria	Mercuria New Zealand Limited
Mercury	Mercury NZ Limited
MEUG	Major Electricity Users Group
Meridian	Meridian Energy Limited
MSOs	Market Security Options
MW	Megawatts

Neoen	Neoen New Zealand Limited
Nova Energy	Nova Energy Limited
NZ-WEM	New Zealand Winter Energy Margin
Octopus	Octopus Energy NZ Limited
Option Capacity	Each Counterparty's option to call on up to 50 MW of Core Capacity and an additional 25 MW of Additional Baseload Capacity.
OTC Hedges	Over-the-counter hedges
PPAs	Power Purchase Agreements
Proposed Arrangements	See paragraph 143
Pulse	Bel Investments NZ Limited, trading as Pulse Energy
Rankine Unit	A type of steam-powered electricity generating power plant that can run on gas or coal. Genesis currently operates three Rankine Units at Huntly. Each of Genesis' Units can generate up to 240 MW
Shaped Hedges	See paragraph 76.1
SOSA	Security of supply assessment
SSNIP	Small but significant non-transitory increase in price
Strategic Reserve Stockpile	See paragraph 84.4
Transpower	Transpower New Zealand Limited
Unit 2	One of the Rankine Units at Huntly power station. It is currently scheduled to be decommissioned in 2026.
WEL Networks	WEL Networks Limited

Executive Summary

What is the application for authorisation about?

1. The Commerce Commission (**Commission**) is considering an application for authorisation (**Application**) from Genesis Energy Limited (**Genesis**), Contact Energy Limited (**Contact**), Meridian Energy Limited (**Meridian**), and Mercury NZ Limited (**Mercury**) (together, the **Applicants**) to give effect to a series of agreements (**Proposed Arrangements**) that have been entered into that would extend the life of one of Genesis' thermal generation units for ten years.

2. New Zealand's electricity system is susceptible to 'dry year risk': extended periods of dry weather that lower lake levels, thereby reducing the amount of hydroelectricity that may be generated and increasing the risk that there is inadequate electricity supply to meet demand.

3. Genesis owns the Huntly Power Station in the Waikato. The Huntly Power Station comprises a number of thermal generation units, including three Rankine units (**Rankine Units**). The Rankine Units are well suited to help manage dry year risk. They are coal-powered electricity generators that can be turned on as required during extended dry periods to help ensure sufficient electricity supply.

4. However, the Rankine Units are old, expensive to maintain and run, and their full capacity is often not required by the market. Genesis has determined that without support from other market participants in the form of long-term hedge contracts,[1] it will close one of its Rankine Units in early 2026, referred to in this Draft Determination as 'Unit 2' (**Unit 2**). Unit 2 requires significant investment to recertify if it is to remain operational after February 2026. Genesis has indicated that it does not need Unit 2 to cover its own contracts.

5. The Proposed Arrangements are a form of hedge contract between Genesis and each of the counterparties: Mercury, Meridian and Contact (**Counterparties**). The stated purpose of the Proposed Arrangements is to ensure that Genesis will invest the required capital and operating expenditure to maintain Unit 2 to contribute to security of electricity supply for dry winters. Under the Proposed Arrangements, the Counterparties have agreed to contribute to the capital and operating costs of Unit 2 in exchange for notional generation capacity at a fixed price.

6. More detail on the background and the Proposed Arrangements themselves can be found from paragraph 45.

What feedback have we received from interested parties?

7. As part of our consideration of the Application, the Commission has sought feedback from interested parties on the Proposed Arrangements.

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[1] Hedge contracts are a type of financial instrument that involve the purchase of insurance against electricity price volatility rather than the purchase of physical electricity. Purchasers of hedges receive insurance against high prices and sellers of hedges receive insurance against low prices.

8. The feedback that we have received is that the Rankine Units are a particularly important safeguard for security of supply in New Zealand. There is strong public support for ensuring that all three Rankine Units remain operational in at least the short to medium term while investment in other forms of electricity generation such as solar, wind and hydro generation are being brought to market.

9. However, our public consultation also demonstrates a level of concern about the Proposed Arrangements. Interested parties are concerned about the amount of capacity committed under the Proposed Arrangements, the duration of the contracts, and the identity of the participants (all of whom are generator-retailers (**Gentailers**)).

10. Some interested parties also expressed concern that the Proposed Arrangements would entrench the Applicants' market power, and that the capacity of the Rankine Units will be "locked up" between the Applicants for a significant period (ten years).

How do we assess applications for authorisation?

11. We have explained the legal framework that governs authorisations in detail as part of this Draft Determination.[2]

12. At a high level, the legal question that the Commission must ask itself is whether the public benefits of the Proposed Arrangements are likely to outweigh any detriments associated with the Proposed Arrangements (including any associated harm to competition). This is called the 'public benefit' test.

13. The Commission must not grant authorisation unless it is satisfied that the public benefits of the arrangements are likely to outweigh the detriments.

14. While the Commission has a broad mandate to promote competition and is on record as being dissatisfied with the state of competition in the electricity sector, its legal role in an authorisation process is tightly constrained. The Commission must only consider the conduct for which authorisation is sought as defined by the applicants. It has the option of either declining to grant authorisation, granting authorisation, or granting authorisation with conditions. It may only impose conditions if the conditions enable the Proposed Arrangements to pass the public benefit test (i.e., where without conditions, the detriments would outweigh the benefits).

How do we determine whether the benefits outweigh the detriments?

15. At a high level, the Commission is required to assess what is likely to happen in future if the Proposed Arrangements go ahead (what we refer to as the 'factual') and compare it to what we think is likely to happen if the Proposed Arrangements do not go ahead (what we refer to as the 'counterfactual').

16. We then weigh up the likely public benefits and detriments in the factual compared with the counterfactual to determine whether the Proposed Arrangements are likely

[2] See from paragraph 97.

to result in a net benefit or a net detriment. Further information on this test is available at paragraph 105.

17. Our provisional view is that in the factual Genesis will invest in the necessary operating and capital expenditure to ensure Unit 2 remains in the market. The primary benefit is that electricity supply is more secure.

18. Our consideration of what is likely to happen if the Proposed Arrangements do not go ahead is more complicated.

What do we think is likely to happen if the Proposed Arrangements do not go ahead (what is the likely counterfactual(s))?

19. We have carefully considered what is likely to happen if the Proposed Arrangements do not go ahead based on our public consultation and the evidence received from the Applicants.

20. Some interested parties expressed doubt that Genesis would close Unit 2 if the Proposed Arrangements do not proceed. There is a perception that, given New Zealand's constrained electricity supply (particularly during dry winters), Genesis must be commercially incentivised to keep Unit 2 operating for the foreseeable future. Interested parties also observed that there is strong political interest in the future of the Rankine Units.

21. However, based on evidence received, the Commission is provisionally satisfied that, in the absence of the Proposed Arrangements, the economic incentives on Genesis weigh in favour of the closure of Unit 2. Genesis does not require Unit 2 to fulfil its own customer and hedge contracts and, given the uncertain timing and frequency of dry winters, it considers itself unlikely to recover the costs of recertifying Unit 2 unless it enters into hedge contracts with enough counterparties. We explain this in more detail from paragraph 168.

22. Many interested parties also told us that, instead of the Proposed Arrangements, Genesis would or should issue a public tender to enable a greater number of parties to enter negotiations to purchase Genesis' hedge contracts on a bilateral basis[3] and/or open up the Proposed Arrangements to more counterparties. Those interested parties felt this would be better for competition because in their view the hedge contracts could be negotiated by more parties on differentiated terms.

23. We have carefully assessed whether it would be likely that enough Counterparties and/or other interested parties would enter into bilateral hedge contracts with Genesis if the Proposed Arrangements do not go ahead. We asked other potential purchasers about their interest in Genesis' hedge contracts and their needs and risk appetites when purchasing such contracts.

[3] Ie, these parties have suggested that Genesis should enter a series of bilateral hedge contracts with different counterparties on differentiated terms, rather than a multilateral agreement like the Proposed Arrangements (involving a number of parties all agreeing to the same terms).

24. We have also tested whether other interested parties would have signed up to the Proposed Arrangements with the Applicants (ie, entered a multilateral arrangement on the same or similar terms) if that was an option available to them.

25. In making that assessment, we provisionally accept Genesis' submission that the Proposed Arrangements set out the minimum terms it requires commercially to keep Unit 2 in operation. We note that other interested potential purchasers expressed the view during consultation that Genesis' commercial requirements to keep Unit 2 open are too onerous, and transfer too much risk and cost to Counterparties. However, Genesis' risk appetite and commercial position is a matter for Genesis, not the Commission, to determine. The Commission is provisionally satisfied that Genesis' commercial position would be unlikely to change if, for example, it negotiated with a wider range of counterparties. We consider it is likely that if Genesis' bottom lines are not met, Genesis will close Unit 2.

26. At this stage, the weight of the evidence we have received suggests that it is unlikely that

    26.1. any other interested parties would be interested in accepting Genesis' minimum terms (whether bilaterally or as additional counterparties to the Proposed Arrangements).

    26.2. enough current Counterparties would reach bilateral arrangements with Genesis on the minimum terms required.

27. Furthermore, bilateral or multilateral negotiations with a wider number of parties would be complex and time consuming and would likely not be completed in sufficient time for Genesis to complete the necessary recertification work to make Unit 2's capacity available for winter 2026.

28. For these reasons, the Commission provisionally considers that in the absence of the Proposed Arrangements, Genesis is likely to shut down Unit 2 in accordance with its publicly stated plans.

29. This means that we must identify the likely benefits and detriments of the Proposed Arrangements, which secure the capacity of Unit 2 for the market for a further ten years, and compare them to the likely benefits and detriments of a counterfactual in which Unit 2 is shut down and its capacity is removed from the market.

Why do we think the benefits of the Proposed Arrangements outweigh the detriments?

Benefits

30. We provisionally consider that the Proposed Arrangements are more likely than not to lead to a net public benefit. That is, the Proposed Arrangements are likely to result in public benefits that would outweigh the detriments.

31. That is because, compared to a counterfactual in which Unit 2 is closed down, the Proposed Arrangements are likely to give rise to the following benefits:

31.1. improved security of supply, particularly during 'dry' winters, because the capacity of Unit 2 will remain available to be turned on as needed to support security of supply during dry years;

31.2. lower wholesale electricity prices and/or reduced price volatility. Current evidence indicates that lower wholesale prices will produce a sizeable public benefit, potentially in the range of $13.5m – $15.8m over the next five years; and

31.3. a significant amount of Rankine Unit capacity (135 megawatts (**MW**)) remains unallocated and is available to be contracted to third parties. Genesis has stated as part of the Application that if the Proposed Arrangements proceed, it intends to design hedge products that are suitable for the needs of a wider range of interested parties.

32. The Commission takes note of Genesis' commitment in the Application to design products that are suitable for the needs of interested parties (such as financial intermediaries, independent retailers, generators, and industrial customers) and expects Genesis to promptly follow through on that commitment consistent with its statements in the Application. We expect these products to be offered on fair and reasonable terms, and to take into account that Genesis has already secured the capital and tenure it deems necessary to commit to keeping three Rankine Units in market.

Detriments

33. We have also assessed whether the Proposed Arrangements would give rise to detriments compared to a counterfactual in which Unit 2 is retired. Our provisional view is that any detriments are likely to be minimal:

33.1. The Proposed Arrangements are unlikely to facilitate or enhance coordinated behaviour by or between the Applicants (rather than ensure competition between them) because of the generally transparent nature of the market and asymmetry in the Applicants' generation assets and load commitments.

33.2. Any potential reduction in incentives to invest in more efficient generation than the Rankine Units as a result of the Proposed Arrangements is likely to be minor if it occurs at all. We provisionally think that there will still be incentives to invest in other generation. This is due to the unique characteristics of the Rankine Units, which have few substitutes during dry winters but which are materially more expensive to run than renewables, and so are unlikely to displace renewable generation outside of dry winters.

33.3. Any increase in the volume of carbon emissions as a result of the Proposed Arrangements would likely be minimal and would only constitute a small public detriment that is internalised by the fact that carbon credits must be bought to cover the emissions.

33.4. It is unlikely that the Proposed Arrangements increase the ability or incentives of Genesis and/or the Counterparties to exercise market power in the spot market:

~~33.4.1.~~ If the Proposed Arrangements go ahead, the presence of Unit 2 will increase capacity in the market and reduce Genesis' market power in the spot market (compared to a world in which Unit 2 is disestablished).

~~33.4.2.~~ If Genesis attempted to use the Rankine Units to exercise market power in the spot market (ie, to increase spot prices) it would need to pay the Counterparties if spot prices exceeded the electricity price agreed under the Proposed Arrangements (if the Counterparties elected to call their hedge options).

~~33.4.3.~~ In the counterfactual, Genesis alone would control the allocation of Huntly capacity. The Proposed Arrangements allow for capacity to be shared among the Counterparties (and Counterparties could enter into secondary trades, further competing with Genesis). The allocation of capacity to a greater number of parties, who compete on the on-selling of this capacity, limits rather than increases Genesis' market power in the factual.

34. Overall, the Commission's assessment at this stage is that the benefits of the Proposed Arrangements outweigh the public detriments, regardless of the frequency of dry years over the authorisation period. Therefore, we are provisionally satisfied that, in all scenarios, the Proposed Arrangements will likely result in a net public benefit.

35. Having regard to the need for Genesis to recover the upfront investment over a commercially feasible timeframe and given our overall assessment of the likely benefits and detriments, we provisionally consider it appropriate to authorise the Proposed Arrangements for 10 years.

Timeframe for our final determination

36. As explained in further detail later in this determination, the goal of the proposed Arrangements is to keep Unit 2 (which is scheduled to be retired in early 2026) in service beyond its planned end of life. Keeping Unit 2 operational provides greater national security of supply, especially during dry winters.

37. To achieve this goal for the 2026 winter, Genesis has told us that it requires the certainty of an authorisation by November 2025. This will provide it with sufficient time to undertake investment in Unit 2.

38. The Commission notes that the challenges for security of supply are not new and the timing issues will have been well known to Genesis. In view of the serious timing constraints faced by the Genesis and the Counterparties heading into the winter of 2026, we are surprised that the Applicants took the commercial risk of filing this

Application as late as August 2025, knowing that the statutory deadline for the Commission's decision is 16 February 2026.

39. As a result of this delay by the Applicants, we have needed to (and have) dealt with the Application as a matter of urgency and under a substantially accelerated timetable. In the future, we caution parties not to delay filing complex authorisation applications on the assumption that a substantially expedited process will be possible. Parties who do not provide the Commission with adequate time to assess the relevant issues do so at their own risk.

Consultation on Draft Determination

40. The Commission now seeks written submissions on the Draft Determination prior to making its final determination. Submissions should be received by the Commission on or before midday on 10 October 2025.

41. The Commission may decide to hold a conference prior to making a final determination. However, it is the Commission's view that a conference is unnecessary and/or disproportionate at the present time.

Introduction

42. On 4 August 2025, the Commission received an application from the Applicants. The Applicants seek authorisation under sections 58(1), 58(2), 58(6B) and 58(6D) of the Commerce Act 1986 (**Act**) to enter into and give effect to what the Applicants refer to as the 'Huntly Strategic Energy Reserve Huntly Firming Option' (**HSER HFO**).

43. In particular, the Applicants seek authorisation to enter into and give effect to the Proposed Arrangements, which comprise:

    43.1. a bilateral International Swaps and Derivatives Association (**ISDA**) Master Agreement and ISDA Schedule between Genesis (as floating price payer) and the relevant buyer/fixed price payer (one of the Counterparties);

    43.2. a bilateral Swaption Confirmation between Genesis and the counterparty; and

    43.3. a multilateral framework agreement (the **Framework Agreement**).

44. The Applicants are seeking authorisation for the period ending 31 December 2035.

Background

45. In this section we provide relevant background to the Proposed Arrangements, including:

    45.1. the main types of market participants in the wholesale electricity sector;

    45.2. how thermal generation (like the Rankine Units) contributes to security of supply in New Zealand; and

    45.3. the purpose of hedge contracts such as the Proposed Arrangements in the electricity industry.

Market participants

46. The two main types of market participants in the wholesale electricity sector are generators that produce and supply electricity, and purchasers that source and use electricity (either for retailing purposes or as end users). Under the current structure of the industry, many market participants are both suppliers and purchasers.

47. Currently, the Applicants generate approximately 90% of the electricity produced in New Zealand. The Applicants are also the largest retailers of electricity and are commonly referred to as the 'big four' vertically integrated Gentailers.

48. The remaining 10% of electricity produced in New Zealand is generated by several smaller entities. Some of these are smaller vertically integrated gentailers (eg, Nova Energy Limited (**Nova Energy**) and Bel Investments NZ Limited trading as Pulse Energy (**Pulse**),[4] but many do not have a retail arm and are referred to as independent

[4] These entities are technically gentailers as they have both generation and retail arms.

generators. Independent generators include Lodestone Energy Limited (**Lodestone Energy**), Ngāwhā Generation Limited and Eastland Generation Limited.

49. There are also several non-vertically integrated retailers in the market, commonly referred to as independent retailers. Independent retailers include Electric Kiwi Limited (**Electric Kiwi**), 2degrees Limited (**2degrees**), Octopus Energy NZ Limited (**Octopus**), and Pulse.

50. All participants in the industry must comply with the obligations set out in the Electricity Industry Participation Code 2010 (**Code**), which is administered by the Electricity Authority (**EA**).

How thermal generation contributes to security of supply in New Zealand

51. This section sets out:

    51.1. what the Rankine Units are;

    51.2. the challenges New Zealand faces in achieving security of supply at peak times, particularly in dry winters;

    51.3. how thermal generation contributes to security of supply; and

    51.4. how New Zealand's sources of generation are anticipated to change over time.

Rankine Units

52. Genesis currently operates three Rankine Units at the Huntly Power Station, each with a capacity of 240 MW.[5] The Rankine Units are turbine power plants that utilise boiler and steam turbine technology to generate electricity. The Rankine Units can run on either coal or natural gas. Due to the constrained gas supply in New Zealand, the Rankine Units have been running predominantly on coal for the past two years, with Genesis directing available gas to its more efficient Unit 5 (**Combined Cycle Gas Turbine**).[6]

53. In recent years, Genesis has operated up to two Rankine Units to support its own customers and holders of its prior hedge contracts.[7] It has also operated Unit 2 in emergencies (when other plants have not been available) and, with planning, for around three months at a time in dry winters with high demand.[8]

54. Genesis submits that its running of and investment in Unit 2 has reflected an end-of-life strategy. The high-pressure steam boiler and associated plant for the Rankine Units

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5 Genesis Energy Limited (**Genesis**), Contact Energy Limited (**Contact**), Meridian Energy Limited (**Meridian**), and Mercury NZ Limited (**Mercury**) (together, the **Applicants**) "Notice Seeking Authorisation of a Restrictive Trade Practice pursuant to Section 58 of the Commerce Act 1986" (4 August 2025) (**Application**) at [3.9].

6 Application at [3.10].

7 Application at [3.11].

8 Application at [3.11].

must be certified by WorkSafe every four years to remain in operation.[9] However, Unit 2's current certification expires in February 2026.[10] Genesis estimates that the cost of recertifying Unit 2 is approximately [ ].[11]

55. Genesis submits that it intends to retire Unit 2 in January 2026 because its operation is no longer economic.[12] Genesis does not believe that the revenues Unit 2 could generate are likely to offset the costs of recertifying and maintaining Unit 2 and a sufficiently large stockpile of coal onsite to properly utilise the capacity when demanded in the market.[13]

New Zealand faces challenges achieving reliable security of supply at peak times

56. In New Zealand, electricity demand varies significantly over the course of a day. Demand is generally very low during the early hours of the morning and peaks between 7 and 9am, before reducing slightly towards the middle of the day. Demand starts rising again from around 4pm. The evening demand peak is generally between 5 and 7pm and is usually higher than the morning peak. Demand then slowly tails off through the evening and into the early hours of the morning.

57. The size of demand peaks are highly seasonal and weather dependant. During summer months, demand peaks are much lower and there can be little difference between the peak demand periods and the midday 'trough' in demand. During winter months, peak demand can be very high and is prone to unexpected, short-term spikes when cold weather fronts pass over the country.[14]

58. New Zealand faces challenges in achieving reliable electricity around the clock. This is because our electricity is produced by both renewable sources, like wind, hydro, solar and geothermal, and by non-renewable, thermal-fuelled power stations.[15] Renewable sources of energy are constrained by the natural limits of the generation source. For example:

    58.1. Solar generation does not typically produce electricity during the peak demand periods as it is dark, and low wind speeds brought about by cool temperatures impact the contribution of wind generation (which is approximately 10% of New Zealand's electricity generation capacity and growing).[16] This leaves hydro, geothermal and thermal generation to provide the bulk of electricity during peak demand periods.

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9 Section 20 of the Health and Safety in Employment Act 1992. WorkSafe Approved Code of Practice for the Design, Safe Operation, Maintenance and Servicing of Boilers 1996.

10 Application at [1.5].

11 Applicants "Annexure 3: Confidential submission by Genesis on the counterfactual" (4 August 2025) (**Annexure 3**) at 1.

12 Application at [1.6].

13 Application at [1.6].

14 Electricity Authority (**EA**) "The difference between winter peak capacity and dry year risk" (28 May 2024) <www.ea.govt.nz>.

15 EA "The difference between winter peak capacity and dry year risk" (28 May 2024) <www.ea.govt.nz>.

16 EA "The difference between winter peak capacity and dry year risk" (28 May 2024) <www.ea.govt.nz>.

58.2. Geothermal generation runs at near full capacity all of the time and cannot be varied except to be shut down. Thermal and hydro generation with controllable storage are the only forms of generation that can ramp up and down to meet peak demand.

58.3. Over 50% of the electricity generated in New Zealand is from hydro generation. Many hydroelectric generation lakes have storage reservoirs which conserve water for later use.[17] An extended period of low rainfall in New Zealand can lead to lower-than-expected storage levels in the country's hydroelectric power dams ('dry year risk').[18] Lake levels can impact both the ability of generators to provide electricity over an extended period ('energy risk') and the ability for hydro generation to ramp up and down to meet short-term peak demand needs ('capacity risk').

59. Due to the high and increasing level of intermittent, non-controllable renewables in New Zealand's electricity system, it is critical to have access to controllable generation resources with fuel storage to meet demand at peak times and over extended dry sequences.

Thermal generation contributes to security of supply during 'dry' winters

60. Because of the limitations of renewable sources of energy, during winters it may be necessary to use thermal generation to meet electricity demand in peak periods, particularly in dry winters. Thermal generation, particularly gas-fuelled generators, can be flexibly dispatched to meet short-term changes in demand and its fuel source is not weather dependent. In the case of coal, large fuel stockpiles can be maintained for extended periods and used when needed. Coal can also be restocked relatively easily if enough lead time is allowed for ordering and delivery.

61. Thermal generation generally has higher operating costs than other forms of generation because of the cost of fuels (coal, gas and diesel) and associated carbon emissions. This can contribute to higher average electricity spot prices during dry years, leading to a higher overall cost of electricity for consumers that are exposed to the spot market.[19] In the long run, it also incentivises generators to invest in cheaper forms of renewable generation over thermal generation most of the time. However, because of the limits of renewable generation, thermal generation remains an important safeguard for security of supply during dry winters.

62. Historically, dry years have been relatively infrequent, with seven occurring over the last 30 years. However, the frequency (and variability) is expected to increase because

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17 EA "The difference between winter peak capacity and dry year risk" (28 May 2024) <www.ea.govt.nz>.

18 Dry year risk can occur during any season but is intensified in winter when electricity demand is highest. EA "The difference between winter peak capacity and dry year risk" (28 May 2024) <www.ea.govt.nz>.

19 In August 2024, New Zealand experienced a significant electricity price spike, which was driven by a combination of high demand and low hydroelectricity lake levels, reduced gas supply, and low wind generation, which led to insufficient generation. As a result, several electricity users had to scale back and/or temporarily halt operations and some independent electricity retailers struggled to take on new customers because they could not offer competitive prices in the volatile wholesale market. EA "What was behind high wholesale electricity prices" (16 September 2024) <www.ea.govt.nz>.

of climate change.[20] Most recently, New Zealand experienced a dry winter in 2024, when electricity prices on the spot market increased significantly.

63. New Zealand faces challenges in managing dry year risk as its transitions towards a more highly renewable power system. Alternative solutions to the dry year risk are being explored and include options like pumped hydro schemes, peakers, baseload thermal running on renewable fuels (like hydrogen or wood pellets) or over-building renewable generation such as wind and solar.[21] Some of these are discussed in more detail below.

Expected changes to how electricity will be generated

64. The electricity industry is experiencing significant changes, primarily driven by the transition to intermittent renewable energy sources such as solar and wind and the retirement of carbon-producing assets such as thermal generation.[22] Part of this transition involves new generation assets being built, and there is currently a large pipeline of new generation projects from both existing generators and new entrants.[23]

65. While the shift in generation types will contribute to a more sustainable energy mix, the variability of the volumes of electricity that will be generated will necessitate a change in how the industry operates.

    65.1. The transition to renewables is likely to increase volatility in the wholesale spot price for electricity as the intermittent nature of this type of generation will likely lead to greater variability in supply. This is because intermittent sources of energy are reliant on suitable weather conditions (ie, solar generation requires the sun to be shining, and wind generation requires it to be windy).

    65.2. While supply is becoming more variable, demand for electricity is forecast to increase due to increased demand from commercial and industrial sectors, the rise in electric vehicles, the switch from fossil fuel usage to electricity, and a rise in residential electricity demand for heating.[24]

66. Given challenges achieving reliable security of supply at peak times and the intermittent nature of renewables, reliance on some form of thermal firming capacity remains important.

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20 Application at [3.6]. Jen Purdie "Climate change impacts on New Zealand hydro catchment inflows & wind speeds" (February 2022) Ministry of Business, Innovation and Employment (**MBIE**) <www.mbie.govt.nz>.

21 EA "The difference between winter peak capacity and dry year risk" (28 May 2024) <www.ea.govt.nz>.

22 EA "Reviewing risk management options for electricity retailers – issues paper" (7 November 2024) <www.ea.govt.nz> at 3.

23 [ ] [ ] EA "Generation investment pipeline" (16 September 2025) <www.ea.govt.nz>.

24 The results of MBIE's Electricity Demand and Generation Scenarios show that electricity demand is expected to rise in all forecast possible future demand scenarios. See MBIE "Electricity Demand and Generation Scenarios: Results summary" (July 2024) <www.mbie.govt.nz> at 1.

67. Further, with the industry in transition, there is the potential for new products and new technologies to be introduced.[25] For example, battery capacity is being introduced in New Zealand, which may enable electricity from existing generation assets to be stored during off-peak periods and then deployed during super-peak periods. If introduced at scale, battery technology may improve security of supply.

The wholesale electricity price and the role of hedge contracts

68. The Proposed Arrangements are a form of hedge contract which the Applicants have entered to incentivise Genesis to invest in the ongoing operation of Unit 2.

69. This section explains how hedge contracts are used to manage spot price volatility in the electricity industry, by describing:

    69.1. how the wholesale price of electricity is determined; and

    69.2. how hedge contracts such as the Proposed Arrangements support the industry to manage volatility in the wholesale price; and

    69.3. how Genesis has previously (ie, prior to the Proposed Arrangements) offered hedge contracts backed by Huntly capacity.

How the wholesale price of electricity is determined

70. Purchasers of wholesale electricity (retailers and large commercial and industrial electricity end users) pay the 'spot price' for the physical electricity they purchase.

    70.1. The spot price of electricity differs depending on the combination of supply, demand, and the distance from the source of the electricity generated.[26]

    70.2. The spot price for each half hour trading period is set by the price offered by the last (most expensive) power station whose power is required to fulfil the demand. All generators whose power is required to fulfil wholesale demand in the particular trading period are then paid that spot price for the electricity they generate.

    70.3. The spot price can be volatile depending on market conditions. The EA notes that the volatility in the spot price is because supply and demand vary depending on factors like cold weather (which increases demand) and the amount of wholesale electricity available (which can vary based on how dry the

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[25] For example, see EA "Reviewing risk management options for electricity retailers – issues paper" (7 November 2024) <www.ea.govt.nz> at 2.

[26] Generators submit 'offers' to supply electricity in half hour increments, and large industrial customers submit 'bids' for electricity to be supplied. The remaining demand is forecast by Transpower as the System Operator for each half hour period and is considered inflexible unless flexibility bids are submitted. The price is calculated in half hour increments based on this information for ~220 pricing locations ('nodes') across the country. See EA "Spot market" <www.ea.govt.nz>.

lakes are at a generator's hydropower station or the amount of wind at a generator's windfarm).[27]

71. All generators sell electricity to, and purchasers buy energy from, a central agency known as the 'clearing manager' (**Clearing Manager**) at the relevant spot price. Because all direct generation and purchase transactions must happen via the Clearing Manager, direct sale agreements between generators and purchasers take the form of hedge contracts.

How hedge contracts such as the Proposed Arrangements support the industry to manage volatility in the wholesale price

72. Exposure to spot price volatility creates risk for both purchasers and suppliers of electricity. For a spot market purchaser, such as an electricity retailer, high price periods can lead to times where the cost of purchasing electricity on the spot market is higher than the price the retailer can sell it to consumers for. Conversely, generators want to avoid exposure to periods of low spot prices that may be below their average total cost of production.

73. Industry participants can manage these risks in several ways, including by entering hedge contracts. Hedge contracts are a type of financial instrument that involve the purchase of insurance against spot price volatility rather than the purchase of physical electricity. In a typical hedge contract arrangement, the purchaser will agree to pay a fixed price for a notional quantity of electricity, while the seller, usually a generator, will pay the purchaser the spot price they received from the Clearing Manager for the agreed quantity. As the purchaser has already paid the Clearing Manager for the quantity of electricity and the generator has been paid by the Clearing Manager, the hedge contract settles the difference between the spot price and the agreed hedge price for the electricity. For this reason, the contracts are typically called 'contracts for difference' (**CFDs**). The effect of this type of arrangement is that the purchaser of a hedge receives insurance against high spot prices, and the seller receives insurance against low spot prices.

74. Hedge contracts can have a wide variety of structures and terms. Hedge contract terms can vary by the volume of electricity covered by the hedge, the trading periods and/or times that the hedge relates to, and/or the channel through which the hedge is supplied. We briefly discuss some relevant types of hedges below.

75. The electricity volumes covered by a hedge can be variable or fixed.

    75.1. Variable volume hedges are those where the volume of electricity covered varies (the price of the electricity can be fixed or variable). For example, a generator might sell a variable volume contract (also known as a power purchase agreement (**PPA**)) linked to all or some proportion of the output from an individual plant.

[27] For example, see EA "Past and future spot market volatility" (8 April 2024) <www.ea.govt.nz>.

75.2. Fixed volume hedges are those where the volume of electricity covered by the hedge contract is fixed for the period of the contract (the price of the electricity can be fixed or variable).

76. The electricity trading periods covered by a hedge can also vary. This is most relevant for fixed volume hedges, which can be 'shaped' to a particular period of a day or a week (**Shaped Hedges**).

76.1. Shaped Hedges are generally those that cover specific time periods such as the morning and the evening when electricity demand tends to be at its highest (intra-day).[28] In addition to intra-day periods, Shaped Hedges can also cover intra-week periods as well as inter-seasonal periods. As such, any product which covers a level of volume that changes in specified time periods can be classified as a Shaped Hedge.[29] Shaped Hedges are typically provided by generators with flexible types of generation (such as hydro and thermal) as the amount of generation these assets produce can be increased or decreased by the generator.

76.2. Alternatively, there are hedges that cover all periods during the duration of the hedge, commonly referred to as baseload hedges (**Baseload Hedges**). Baseload Hedges are typically provided by generators with a portfolio of assets that together can provide the required energy at a relatively consistent level.

77. Various independent generators and retailers advised the Commission that they require access to Shaped Hedges to better manage risks around spot price volatility during periods of high demand. These products allow them to be more competitive on price and to therefore compete more successfully for customers.[30]

78. The channel through which a hedge is supplied (or traded) can vary and this can also impact what is covered by a particular hedge contract. There are three main channels for the trading of hedges:[31]

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28 For example, 'peak' Shaped Hedges generally cover volumes for trading periods between 7am and 9pm, and 'super-peak' Shaped Hedges generally cover trading periods between 7am and 10.30am and between 5pm and 9pm.

29 For example, a Shaped Hedge could cover X volumes per day during the weekend but X+Y volumes per day during the working week.

30 [ ] [ ] [ ]

31 In addition, the EA recently introduced a standardised super-peak Shaped Hedge contract, enabling customers to manage spot price risk during periods when demand is likely highest (mornings and evenings) and intermittent generation (eg, solar farms) may be low. Interested parties can voluntarily trade this product through an appointed broker. Customers can also purchase financial transmission rights. Electricity can be transmitted between different parts of the country (through different nodes) but the longer the distance of transmission, the larger the electricity losses incurred. As a result, there are differences in spot prices across different nodes. Financial transmission rights protect against these geographic differences in spot prices.

78.1. Australian Securities Exchange hedges (**ASX Hedges**) – the ASX hosts a range of New Zealand-electricity based hedge contracts, including baseload, peak, and option contracts.

78.2. Standardised flexibility products – These products are traded anonymously over the Aotearoa Energy trading platform during fortnightly trading windows. They offer hedge cover for morning and evening demand peaks and can be bought as calendar month or quarterly hedges.

78.3. Over-the-counter hedges (**OTC Hedges**) – OTC Hedges are traded via bilateral negotiations between buyers and sellers and so, unlike ASX Hedges, can be negotiated to suit each party's particular requirements.

79. The Proposed Arrangements are an OTC Hedge that provides the Counterparties with the option to enter into CFDs with Genesis over the 10-year term. Counterparties can choose the volume that is fixed for each CFD they enter into, as well as its profile (eg, baseload or shaped), subject to the terms and conditions of the contract. The characteristics of the Proposed Arrangements are described in more detail below.

How Genesis has previously offered hedge contracts backed by Huntly capacity.

80. Genesis' approach to designing and offering risk management products such as hedge contracts has evolved over time. As well as trading hedge products via the ASX, Genesis has entered into several different bilateral arrangements to provide Rankine Unit capacity as a hedge product:

80.1. Historically, Genesis offered swaption arrangements.[32] These were bilateral contracts which supported the cost of maintaining the Rankine Units by having the relevant counterparty pay a premium to Genesis in exchange for a fixed price call option. The swaptions typically involved a significant portion of capacity allocated to one or two counterparties.[33] The last of these expired at the end of 2021.[34]

80.2. Genesis offered Market Security Options (**MSOs**) into the market in 2022 and then Huntly Firming Options (**HFOs**) in 2024.[35]

80.2.1. The MSOs offered a relatively inflexible option to access Huntly generation capacity, again with a premium to cover associated capital and operating expenditure.[36] Subject to the counterparty pre-purchasing sufficient coal to meet their call, Huntly capacity could be called with 24 hours' notice but had to be used continuously for at least 5 days. The terms required a run of 24 hours per day over the full call period with some ability to shape the call between peak and off-

32 Application at [9.8].

33 Gavin Evans "Meridian buys power from rival Genesis" (13 February 2019) Newsroom <www.newsroom.co.nz>.

34 Application at [4.10].

35 Application at [9.8].

36 Genesis "Market Security Options" (August 2022) <www.media.genesisenergy.co.nz>.

peak periods. The fixed price for a call was tied to the daily international coal Newcastle settlement price, which introduced significant uncertainty in the actual cost of the option for counterparties, particularly at a time of significant international coal price increases due to the Russian invasion of Ukraine.

80.2.2. The HFOs differed from the MSOs because they could also be used to help mitigate against peak supply risks and shorter duration constraints. The HFOs provided counterparties with greater call profile flexibility to help hedge price risk, tailored to the specific shape of their portfolios.[37]

81. Genesis is no longer offering its MSO and HFO products, and has stated these products have not provided sufficient certainty (in terms of revenue and tenure) to justify the necessary investment to maintain three operational Rankine Units.[38] The Proposed Arrangements are different to previously offered MSOs and HFOs including, for example, their tenure (the Proposed Arrangements last 10 years), premium payable (which is higher under the Proposed Arrangements), and the requirement for Counterparties to contribute to a coal stockpile (which was not a requirement of MSOs or HFOs).

82. However, as explained in more detail below, Genesis has submitted that 135 MW of Rankine Unit capacity remains unallocated, and that it intends to offer further hedge products backed by this capacity in the future. It is currently considering the form that these products will take.

The Proposed Arrangements

83. In summary, the Proposed Arrangements provide each of the Counterparties an option to access certain notional generation capacity from Genesis' Rankine Units at the Huntly Power Station at a fixed (or 'strike') price.[39] As part of the Proposed Arrangements, the Counterparties have agreed to contribute to the capital and operating costs of Unit 2.

84. The Applicants summarise the Proposed Arrangements in the Application and in additional information provided to the Commission as follows:

84.1. each Counterparty has an option to call a certain volume of hedge cover at a price equal to the cost of the 'relevant coal' (being the average price of coal in a Counterparty's notional coal ledger) multiplied by an efficiency modifier (which varies for each permitted 'option profile');[40]

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37 Genesis "Huntly Firming Options" (May 2024) <www. media.genesisenergy.co.nz> at 2.

38 Application at [4.10].

39 Application at [1.8]-[1.9].

40 We understand that an option profile refers to the 'shape' of the underlying hedge cover (see discussion above for an explanation of Shaped Hedges). Previous option contracts Genesis offered to market included four option profiles: long-duration baseload (≥ 5 days duration); short-duration baseload (≤ 4

84.2. in exchange for the option to access hedge cover, the Counterparties pay an annual premium to Genesis. The 10 year per annum premium under the Proposed Arrangement is greater than the premiums paid by purchasers of Genesis' prior MSO/HFO products;[41]

84.3. each Counterparty's right to access hedge cover comprises core capacity (**Core Capacity**) and additional baseload capacity (**Additional Baseload Capacity**). In practical terms, each Counterparty will have an option to call on up to 50 MW of Core Capacity, as well as an additional 25 MW of Additional Baseload Capacity available in certain circumstances (**Option Capacity**);[42]

84.4. the Framework Arrangement establishes a coal ordering process, under which the Counterparties agree to pay a price for notional coal and Genesis has an obligation to use reasonable endeavours to acquire physical coal for a "Strategic Reserve Stockpile" (**Strategic Reserve Stockpile**);[43]

84.5. the Strategic Reserve Stockpile will be initially set at 600 kilotons (**kt**) and needs to be maintained at the target level ahead of each winter. Each Counterparty will initially be required to pay for a quarter (150 kt) of the Strategic Reserve Stockpile at the prevailing market price for coal;[44]

84.6. to exercise an option, a Counterparty must ensure it has prepaid Genesis for sufficient notional coal on its "ledger" and the coal must have been delivered to Huntly for Genesis to generate the MW it is calling for;[45]

84.7. each Counterparty must secure and deliver to Genesis sufficient carbon units to cover the notional emissions associated with the MW it has called pursuant to the Proposed Arrangements in the prior year;[46]

84.8. Genesis will maintain full control of all plant operating decisions, including whether a Rankine Unit is turned on in response to calls and the price at which all Rankine Unit capacity is offered to the market;[47]

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days duration); peak (any 15-hour block during a day); and superpeak (any two non-contiguous 3.5-hour blocks during a day). See Genesis "Huntly Firming Options" (May 2024) <www.media.genesisenergy.co.nz>. Efficiency modifiers are a mechanism to reflect the different cost and efficiency of generating a particular MW of electricity using a Rankine Unit for the profile and duration of the related option. See Application at [5.4(e)]. An explanation of these previous option contracts is set out at paragraph 80.

41 Application at [5.4(b)]. Applicants "Authorisation Application – Additional Information" (9 September 2025) (here) (**Application – Additional Information**) at [1].

42 Application at [5.4(d)].

43 Application at [5.4(f)].

44 Application – Additional Information at [2].

45 Application at [5.4(g)]. This differs to Genesis' 2022 MSOs and 2024 HFOs currently in the market where the counterparty is not required to prepay for notional coal orders before the option is called. For further information about the price payable for the option, see Application – Additional Information.

46 Application at [5.4(g)].

47 Application at [5.4(h)].

84.9. mechanically, the Proposed Arrangements will be settled by way of a financial hedge;[48]

84.10. the Proposed Arrangements are for a term of 10 years, ending on 31 December 2035. A Counterparty may elect to exit the Proposed Arrangements after five years, on payment of an early exit fee equal to 80% of the aggregate annual premium due for the remaining five years. Counterparties can also exit by on-selling their option to third parties with Genesis' prior consent;[49]

84.11. Genesis retains discretion as to what it does with the capacity from the Rankine Units;[50] and

84.12. the Proposed Arrangements include a detailed suspension event regime, which permits Genesis to suspend a called swap in specified circumstances.[51]

85. The Proposed Arrangements differ from Genesis' prior HFOs and MSOs because:

85.1. the terms and conditions of the Proposed Arrangements and the fixed price paid for the hedge contracts have been jointly agreed between the Applicants, whereas previously Genesis offered firming capacity to market participants to bid for (in competition with each other) on a bilateral basis;[52] and

85.2. as noted above, the terms and conditions of the Proposed Arrangements are different to prior arrangements including, for example, their tenure (10 years), the premium payable, and the requirement to contribute to a coal stockpile.

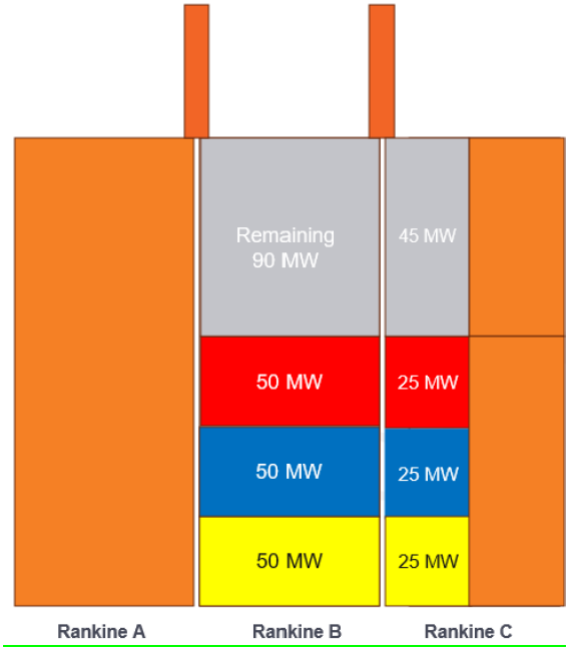
86. The Applicants are seeking authorisation until 31 December 2035.[53]

Unallocated Rankine Unit capacity

87. The Applicants submit that, after the Proposed Arrangements are considered, a significant amount of Rankine Unit capacity (135 MW) will remain available for contracting to third parties across the three Rankine Units that will remain in operation. The illustration below sets out how Genesis considers the allocation of Rankine Unit capacity between itself, the three Counterparties and the available capacity for further contracting.[54]

48 Application at [5.4(i)].
49 Application at [5.4(m)]. Application – Additional Information at [3].
50 Application at [5.4(k)].
51 Application – Additional Information at [6].
52 Application at [4.10] and [5.4].
53 Application at [5.6].
54 Application at [9.6].

Figure 1: Illustrative Rankine capacity allocation[55]



88. Further, pre-existing hedge contracts for Huntly capacity will roll off at the end of 2026. This will provide for a further 85 MW of capacity to be available to the market from January 2027.[56]

Assessment procedure

89. In preparing this Draft Determination, we sought submissions and obtained information from a wide range of sources. The Commission:

    89.1. reviewed the information and analysis in the Application;

    89.2. considered evidence received from the Applicants and interested parties by way of interview and in response to information requests; and

    89.3. considered submissions made by various interested parties in response to the Commission's Statement of Preliminary Issues relating to the Application.[57]

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55 Genesis' retail and other hedge customer obligations are represented in Figure 1 in orange and the allocation of capacity to the HSER HFO is represented in red, yellow and blue. The remaining unallocated capacity is represented in grey. Unit 2 is represented in Figure 1 as 'Rankine B'.

56 Genesis, "Huntly Firming Options" (May 2024) <https://media.genesisenergy.co.nz/genesis/investor/2024/genesis_huntly_firming_options.pdf>. Genesis, NZX Market Release (12 August 2024) <https://media.genesisenergy.co.nz/genesis/investor/2024/huntly_firming_options_august_2024.pdf>. This capacity is currently allocated to Genesis' retail and other hedge customer obligations and makes up part of the orange segment in Figure 1.
[ ] Interview with Genesis Energy Limited (**Genesis**) (21 August 2025) at [7.1]. Genesis response to RFI dated 20 August 2025 (9 September 2025) at 4 and Annex 1. Genesis response to RFI dated 1 September 2025 (6 September 2025) at 7.

57 Commerce Commission "Statement of Preliminary Issues" (6 August 2025) <www.comcom.govt.nz>.

90. The Commission remains open to receiving further information to assist it to make a final determination.

Summary of submissions

91. The Commission received a range of submissions from organisations and businesses on the Application and the Statement of Preliminary Issues.[58] The Commission considered all submissions it received.

92. The parties that made submissions were:

    92.1. *Public bodies and associations*: Transpower New Zealand Limited (**Transpower**), Independent Electricity Generators Association (**IEGA**), Major Electricity Users Group (**MEUG**), and Energy Resources Aotearoa;

    92.2. *Electricity distribution companies*: WEL Networks Limited (**WEL Networks**);

    92.3. Independent gentailers: Lodestone Energy;

    92.4. *Independent energy trading groups*: Mercuria New Zealand Limited (**Mercuria**), emhTrade Markets Limited (**emhTrade**), and Haast Energy Trading Limited (**Haast Energy**);

    92.5. *Independent retailers*: 2degrees, Pulse, and Electric Kiwi Limited and Neoen New Zealand Limited (**Neoen**); and

    92.6. *Commercial and industrial customers*: Fletcher Building Limited (**Fletcher Building**).

93. We provide a brief summary of submissions, noting that views expressed by submitters are discussed in more detail throughout our analysis in this Draft Determination.

94. Submissions that were supportive agreed that the additional capacity made available through the Proposed Arrangements would improve the security of supply in New Zealand,[59] reduce wholesale price volatility,[60] and/or reduce wholesale prices.[61] Some parties raised that the 135 MW of free Rankine Unit capacity[62] would ensure

58 Submissions are available on the Commission's website (here).

59 Submission from WEL Networks Limited (**WEL Networks**) (21 August 2025) at 1. Submission from Transpower New Zealand Limited (**Transpower**) (26 August 2025) at [3]. Submission from Lodestone (27 August 2025) at 1 and 3. Submission from Independent Electricity Generators Association (**IEGA**) (27 August 2025) at 2. Submission from Fletcher Building Limited (**Fletcher Building**) (26 August 2025) at 1. Submission from Energy Resources Aotearoa (27 August 2025) at [3], [5]-[8] and [23]-[24]. Submission from Major Electricity Users Group (**MEUG**) (4 September 2025) at [4] and [8].

60 Submission from WEL Networks (21 August 2025) at 1. Submission from Fletcher Building (26 August 2025) at 1.

61 Submission from Energy Resources Aotearoa (27 August 2025) at [9], [19] and [23].

62 See paragraph 87 above.

additional firming products could be made available to independent retailers, which would promote broader market access and competition.[63]

95. However, some submissions expressed concern that the Proposed Arrangements would reduce the incentives on the Applicants to build new thermal generation or renewable generation,[64] and to offer firming options/hedges to the market. They suggested that the Proposed Arrangements could have the effect of higher consumer prices.[65]

96. In addition, some parties were concerned that the Proposed Arrangements would entrench the market power of the Applicants by excluding other interested parties from the Proposed Arrangements and creating information asymmetries,[66] increasing the Applicants' incentives in the long-term to exercise market power,[67] and increasing the risk of coordinated behaviour between the Applicants.[68]

Our framework

Statutory framework

97. Under section 58 of the Act, the Commission can grant authorisation for restrictive trade practices. This includes authorising conduct that may breach section 27 (contracts, arrangements or understandings substantially lessening competition prohibited) and/or section 30 (contracts, arrangements, understandings or covenants containing cartel provisions prohibited) of the Act.

98. A two-stage assessment is undertaken in any authorisation application under section 58 of the Act.

99. First, confirming the jurisdictional threshold:

    99.1. for applications pursuant to subsections 58(1) and (2) (the **Competition Authorisation Sections**), whether section 27 might apply to the agreement; or

    99.2. for applications pursuant to subsections 58(6B) and (6D) (the **Cartel Authorisation Sections**), whether the agreement might contain a cartel provision.[69]

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63 Submission from WEL Networks (21 August 2025) at 1. Submission from Lodestone (27 August 2025) at 1.

64 Electric Kiwi and 2degrees raised potential evidence of under-investment, negative portfolio effects, and reduced incentive to build new thermal generation. Submission from Electric Kiwi (27 August 2025) at [24]. Submission from 2degrees Limited (**2degrees**) (27 August 2025) at 3.

65 Submission from Pulse Energy (26 August 2025) at 1. Submission from emhTrade Markets Limited (**emhTrade**) (1 September 2025) [Public] at 6. Submission from Haast Energy Trading (**Haast Energy**) (13 August 2025) at [2]-[3].

66 Submission from Pulse Energy (26 August 2025) at 2. Submission from Electric Kiwi (27 August 2025) at [3] and [8]. Submission from Haast Energy (13 August 2025) at 1.

67 Submission from Electric Kiwi (27 August 2025) at [36]-[39].

68 Submission from Haast Energy (13 August 2025) at 2-3. Submission from emhTrade (1 September 2025) [Public] at 7.

69 Section 61(9) of the Act.

100. Second, establishing whether the Commission is able to grant authorisation on the basis of the public benefit test, under:

    100.1. section 61(6) of the Act for the Competition Authorisation Sections; or

    100.2. section 61(8) of the Act for the Cartel Authorisation Sections.

101. We take into account any conditions we may impose at this point.

Jurisdictional threshold

102. The Applicants have applied for authorisation under the:[70]

    102.1. Competition Authorisation Sections, which set out that a person who wishes to:

        102.1.1. enter into a contract, arrangement or understanding (section 58(1)); or

        102.1.2. give effect to a provision in a contract, arrangement or understanding (section 58(2)),

    to which section 27 would or might apply, may apply to the Commission for an authorisation to do so, and the Commission may grant an authorisation; and

    102.2. Cartel Authorisation Sections, which set out that a person who wishes to:

        102.2.1. enter into a contract, arrangement or understanding or covenant that contains a provision that is, or might be, a cartel provision (section 58(6B)); or

        102.2.2. give effect to a provision of a contract, arrangement, understanding or covenant that is, or might be, a cartel provision (section 58(6D)),

    may apply to the Commission for authorisation to do so, and the Commission may grant authorisation.

103. Under the Competition Authorisation Sections, the Commission has jurisdiction to consider an application for authorisation where the proposed contract, arrangement or understanding is likely to lessen competition. This arises from section 61(6) of the Act, which contains the substantive public benefit test but also gives rise to a jurisdictional issue – requiring the Commission be "satisfied" that the conduct defined in the application, in all the circumstances, result or be likely to result in a lessening of competition.[71] Section 61(6A) of the Act specifies that a "lessening of competition" includes a lessening of competition that is not substantial (which is a lower threshold than applies under section 27 of the Act).

104. Under the Cartel Authorisation Sections, the Commission's jurisdiction arises from section 61(8) of the Act. Section 61(9) of the Act further clarifies that under section

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70 Application at [6.1].

71 *Re Weddel Crown Corporation Ltd,* CCOM Decision No 205, 22 July 1987 at [18] and [20].

61(8), for the purpose of the Cartel Authorisation Sections, it is not necessary for the Commission to determine whether a particular provision is in fact a cartel provision, as long as there are reasonable grounds for believing that it might be.[72]

Public benefit test

105. Although the jurisdictional thresholds are expressed differently in the Competition Authorisation Sections and Cartel Authorisation Sections,[73] the public benefit test is materially the same.[74]

106. The Commission can authorise an arrangement if it is satisfied that a proposed arrangement will, in all the circumstances:

    106.1. in relation to the Competition Authorisation Sections, be likely to result in a benefit to the public which would outweigh the lessening of competition;[75] or

    106.2. in relation to the Cartel Authorisation Sections, be likely to result in such a benefit to the public that the matter should be permitted.[76]

107. Courts have taken a consistent approach to the assessment of public benefits in authorisation decisions. That is, Courts have applied a fact-based assessment of the benefits and detriments, adopting a quantitative approach where possible.[77] Courts have also permitted the use of a qualitative assessment of all the benefits and detriments from a proposed arrangement, including those that cannot be quantified in monetary terms.[78]

108. In each case, the Commission needs to investigate and assess the nature, likelihood, and magnitude of any benefits and detriments that might arise from the proposed arrangements.

109. The benefits and detriments which are balanced in the public benefit test must arise from the proposed arrangements for which authorisation is sought.[79] To determine whether the benefits and detriments are specific to the proposed arrangements, we assess:

    109.1. what is likely to occur in the future with the arrangement (the factual); and

    109.2. what is likely to occur in the future without the arrangement (the counterfactual).

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72 Section 61(9) of the Act.
73 Sections 58(1)-(2), 58(6B) and (6D) of the Act.
74 Commerce Commission "Authorisation Guidelines" (June 2023) <www.comcom.govt.nz> (**Authorisation Guidelines**) at [19].
75 Section 61(6) of the Act.
76 Section 61(8) of the Act.
77 Authorisation Guidelines at [51].
78 Authorisation Guidelines at [7].
79 Authorisation Guidelines at [43].

110. Once we have identified all likely benefits and detriments, we then assess the value of those benefits and detriments. When making that assessment, factors we may take into account include how the conduct could affect:

    110.1. allocative efficiency – whether the conduct would raise or lower margins, and whether it would reduce or improve quality, choice or other elements of value to consumers;

    110.2. productive efficiency – whether the conduct could improve or worsen the cost of production processes; and

    110.3. dynamic efficiency – whether the conduct could assist or hinder efficient innovation in products or processes.

111. New Zealand Courts have recognised that efficiencies are not the only benefits and detriments which are relevant to the Commission's assessment.[80] As such, the Commission is not limited to considering efficiencies. Rather, the Commission assesses what benefits accrue to the public in the circumstances of any given case.[81]

112. If we are satisfied that the benefits of the arrangement likely outweigh the detriments, we will grant authorisation. If we are not satisfied, we will not grant authorisation.[82]

Conditions and period of authorisation

113. We can authorise agreements subject to conditions and for a period we consider appropriate.[83]

114. If we decide to impose conditions on an authorisation, these must be consistent with the Act.[84] We may include conditions that remove or lessen the detriments arising from an agreement or unilateral conduct, or conditions that create or enhance the benefits.[85]

115. When considering whether to impose behavioural conditions, we are mindful that they can carry their own costs. In assessing potential conditions, we will have regard to:[86]

    115.1. how well they achieve their objectives, while minimising the risk of unintended negative consequences;

    115.2. the likely cost of monitoring and enforcement; and

    115.3. the likely compliance costs for the firms involved.

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80 *NZME Ltd v Commerce Commission* [2018] NZCA 389 at [80]-[81].
81 Authorisation Guidelines at [42].
82 Authorisation Guidelines at [49].
83 Section 61(2) of the Act.
84 Section 61(2) of the Act.
85 Authorisation Guidelines at [32].
86 Authorisation Guidelines at [34].

Our assessment of jurisdiction

116. As stated above, the Applicants have applied for authorisation under the Competition Authorisation Sections and Cartel Authorisation Sections of the Act.

117. The Commission may consider that it has jurisdiction under both the Competition Authorisation Sections and Cartel Authorisation Sections. Alternatively, it may consider it has jurisdiction under the Competition Authorisation Sections but not the Cartel Authorisation Sections (or vice versa). The last alternative is that the Commission does not consider it has jurisdiction because:

    117.1. the arrangements do not meet the threshold of "lessening competition" under the Competition Authorisation Sections; and

    117.2. the arrangements do not meet the threshold for the Cartel Authorisation Sections because the arrangements do not contain provisions that are or may be cartel provisions.

Sections 58(1) and (2) – Competition Authorisation Sections

118. The Applicants submit that the Proposed Arrangements "might" raise issues under section 27 of the Act,[87] but that the net effect of the Proposed Arrangements is positive.[88]

119. In relation to the Competition Authorisation Sections, the Applicants consider that the jurisdictional threshold is met to the extent that the Commission concludes that, absent the Proposed Arrangements, two or more of the parties would seek to acquire the relevant products (ie, the HSER HFO) independently. All else being equal, the Applicants submit that the Proposed Arrangements would be likely to hinder or prevent some degree of competition between the parties which would amount to a lessening of competition.[89]

120. The Applicants submitted that the Commission could conclude that, absent the Proposed Arrangements, there is a real chance that:

    120.1. The Counterparties would have each negotiated separately with Genesis or other third parties to secure something akin to the HSER HFO in competition with one or more Counterparties or third parties.[90]

    120.2. If the Counterparties were to negotiate separately with Genesis, they would each have likely sought to negotiate flexible or tailored arrangements. In the factual, the Counterparties are no longer able to secure differentiated terms.[91]

87 Application at [6.7].
88 Application at [6.6].
89 Application at [6.8].
90 Application at [6.9](a)].
91 Application at [6.9](a)(ii)].

120.3. Each of the Applicants would explore and compete for alternative options to meet their contractual obligations in a dry year.[92] There would be competitive tension as each of the Applicants compete for access to these alternative arrangements to acquire firming,[93] compared to with the Proposed Arrangements where the competitive tension or rivalry between the Counterparties for these arrangements is lessened.[94]

121. The Applicants also submit that the Commission might find that there is a real chance a lessening of competition could arise from the transparency of pricing under the Proposed Arrangements, specifically due to the knowledge the Applicants have of the price paid by the other party for their options. The Applicants submit that the fact they each know the approximate price at which the other has transacted with Genesis may, all else being equal, slightly soften competitive tension and therefore lessen competition.[95]

122. We accept the Applicants' submissions on jurisdiction under the Competition Authorisation Sections. Accordingly, we consider we have jurisdiction to assess the Application under these sections.[96]

Relevant markets

123. The term "market" refers to a market in New Zealand for goods or services as well as other goods or services that, as a matter of fact and commercial common sense, are substitutable for them.[97]

124. As part of our assessment of the benefits and detriments of an authorisation, we assess the competitive effects of proposed arrangements on relevant markets in New Zealand. We define markets in the way that we consider best isolates the key competition issues that may arise from the proposed arrangements. However, it may not be necessary to precisely define the boundaries of these markets if the outcome of the assessment is likely to be substantially the same irrespective of the precise scope of the market.

125. The Applicants submit that the Proposed Arrangements affect the relevant market(s) for the generation and wholesale supply of electricity in New Zealand.[98]

126. As part of our assessment, we have considered:

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92 Application at [6.9](b)].
93 Application at [6.9](b)(i)].
94 Application at [6.9](b)(ii)].
95 Application at [6.10].
96 We are satisfied under the jurisdictional test that there "might" be more competitive bilateral negotiations sufficient for the Applicants to cross the threshold for further consideration. However, as explained at paragraphs 180 to 211, for the purposes of the counterfactual assessment, we do not think the possibility of bilateral negotiation reaches the higher threshold of being "likely".
97 Section 3(1A) of the Act.
98 Application at [8.1].

126.1. whether there are separate product markets for the wholesale supply of physical electricity (sold at the spot price) and the supply of electricity hedge contracts, including the supply of Shaped Hedges, which generally reduce financial exposure during certain peak time periods where there is high demand and which are particularly important to independent electricity retailers;[99] and

126.2. whether there are separate temporal markets associated with the wholesale supply of electricity (eg, to reflect different customer demands during certain peak time periods).

127. However, for the purposes of assessing the Proposed Arrangements, we provisionally do not consider it necessary to conclude on the exact boundaries of the market(s) because we do not consider that it would change whether the benefits of the Proposed Arrangements are likely to outweigh the detriments.

Product dimension – physical electricity sold on spot market and hedge contracts

128. The Proposed Arrangements support the continued operation of Unit 2 by Genesis. This affects the amount of physical electricity that Genesis can generate and supply to its wholesale customers, the volume and type of hedges that Genesis makes available to the Counterparties, and the volume and type of hedges that each of the Applicants can supply to third parties.[100] For that reason, we discuss below whether physical electricity and hedge products (whether Shaped Hedges or all hedges) are in the same or separate product markets.

129. The Applicants submit that hedge contracts and spot trading are closely interrelated and substitutable but do not consider that it is necessary to reach a concluded view on the relevant markets.[101] This is because, in their view, the Proposed Arrangements do not harm competition because they enable Genesis to make more capacity available to the market(s) (however defined), and do not place restrictions on when Counterparties may call their options or otherwise operate in the market. The Proposed Arrangements similarly do not restrict or determine how Genesis may choose to operate the Rankine Units.

130. We received some feedback that, while some parties are able to substitute hedge trading and spot trading prices, this is not the case for all parties, including independent generators, independent retailers, and intermediaries (whose role is to warehouse and otherwise support the transfer of risk).[102] On the other hand, we received some feedback that that while both spot and contract markets are affected,

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99 As noted above in paragraph 76.1, Shaped Hedges come in various forms beyond intra-day shapes that generally cover peak trading periods. For example, Shaped Hedges covering a weekly shape may cover higher demand on weekdays, while those with a seasonal shape may cover higher demand in winter months.

100 Third parties include independent generators, independent retailers, industrial customers and financial intermediaries.

101 Application at [8.3]-[8.4].

102 Submission from IEGA (27 August 2025) at 3.

the key issue is whether there is sufficient physical capacity to keep prices competitive and security adequate.[103]

131. In *Contact/Manawa*,[104] the Commission assessed the wholesale supply of physical electricity (sold at the spot price) as distinct from the supply of electricity via hedge contracts (with Shaped Hedges potentially forming a distinct market). This is primarily because we considered that purchasing physical electricity and acquiring hedge contracts to be complements for many market participants (rather than substitutes) and the trading mechanisms were very different:[105]

    131.1. On the demand side, each serves a different purpose. Purchasing electricity on the spot market involves the purchase of physical electricity, whereas hedges do not. Hedges instead involve the acquisition of what is effectively insurance against fluctuations in spot prices. We would expect demand for hedge products to be positively correlated with demand for physical electricity, so that if a hypothetical monopolist were to impose a 'small but significant non-transitory increase in price' (**SSNIP**) on the spot price, some purchasers (to the extent they have demand response) would demand less physical electricity and therefore require less hedge cover to manage their spot price exposure.

    131.2. On the supply side, Gentailers have much less need for hedge cover as operating at both functional levels of the market provides a natural hedge. Thus, for a SSNIP in the spot market to be defeated by trading in the hedge market, the burden of doing so will fall primarily on independent retailers and large customers, who are exactly the customers who most need price insurance and are most likely to already have it.[106] Additionally, rival hedge suppliers that are financial institutions could not easily, profitably, and quickly increase their supply of electricity given that they do not have generation portfolios.[107]

132. In addition, the Commission found that both the wholesale supply of physical electricity and the supply of hedge contracts takes place on a national basis.[108]

133. We see no reason to depart from the Commission's decision in *Contact/Manawa* that it is appropriate to assess the supply of hedge contracts separately from the wholesale supply of physical electricity. We discuss our considerations of a potential separate market for Shaped Hedges below.

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103 Submission from Energy Resources Aotearoa (27 August 2025) at [16].

104 *Contact Energy Limited and Manawa Energy Limited* [2025] NZCC 10 (***Contact/Manawa***).

105 *Contact/Manawa* at [54]-[77]. Purchasing electricity on the spot market involves the purchase of physical electricity (and exposes customer and supplier to potentially volatile spot prices) whereas hedges involve the acquisition of an insurance-like product to protect against high spot prices, allowing wholesale customers and suppliers to manage the risk of price volatility.

106 See *Contact/Manawa* at [61]-[63], which sets out our analysis regarding the SSNIP test.

107 See *Contact/Manawa* at [64]-[67], which sets out our analysis regarding the SSNIP test.

108 See Contact/Manawa at [78]-[79]. Although electricity generators have assets located throughout the country, all the different wholesale market participants advised they competed nationally, and that physical electricity and trading of electricity hedges occurs on a national basis.

Market for Shaped Hedges

134. In *Contact/Manawa*, the Commission considered that Shaped Hedges potentially formed a distinct market.[109]

135. On the demand side, it was noted that Shaped Hedges were not sufficiently close substitutes for Baseload Hedges in the event of a SSNIP because they provide different types of protection from spot price volatility. Shaped Hedges provide targeted protection for specific time periods, while Baseload Hedges provide a consistent level of protection throughout the contract duration.[110] Further, a baseload ASX Hedge is likely to be less substitutable for a Shaped Hedge (particularly inter- or intra-day Shaped Hedges) given that the former is standardised while the latter is often bespoke. However, there are occasions where Shaped Hedges might be somewhat substitutable for Baseload Hedges. For example, a Baseload Hedge could substitute for inter-seasonal Shaped Hedges if a party was to purchase several different Baseload Hedges, which could provide similar levels of protection from spot price volatility.[111] Similarly, there will be times when a PPA can act as an effective substitute for a Shaped Hedge and times when it cannot.[112]

136. On the supply side, in *Contact/Manawa*, the Commission noted that while a generator with a portfolio of flexible generation assets is likely to have the ability to supply different hedge products and is able to quickly switch to supplying Shaped Hedges in response to a SSNIP, not all generators have these flexible generation assets so they may not be able to relatively easily switch to supplying Shaped Hedges in response to a SSNIP.[113]

137. We received submissions in this case which ask us to consider whether the electricity hedge market can be further split into baseload and firming contracts and whether these vary by duration (eg, short, medium and long duration markets).[114]

138. We provisionally do not consider it is necessary for the purposes of our analysis to reach a view on whether Shaped Hedges comprise a separate product market from Baseload Hedges or whether other more granular types of hedge products should be assessed separately. There is generally limited ability to substitute between various types of hedges,[115] and in this case the scope of the market should not impact how we assess competition concerns arising from the Proposed Arrangements.

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109 *Contact/Manawa* at [68].

110 *Contact/Manawa* at [70].

111 *Contact/Manawa* at [70].

112 The Commission in *Contact/Manawa* also noted that other alternatives, such as batteries and Huntly Firming Options, were not developed sufficiently to discipline the price of Shaped Hedges now. See *Contact/Manawa* at [71] and [75].

113 *Contact/Manawa* at [75].

114 Submission from IEGA (27 August 2025) at 2.

115 As discussed above, certain factors may mean that various types of hedges are in fact substitutable. This is affected by the specific profile of any underlying flexible generation assets, the existing hedge book or generation assets of the purchaser, and the extent to which the hedge type protects against spot price volatility.

Customer dimension

139. As set out in *Contact/Manawa*, we do not consider it necessary to define separate markets for any particular customer group when assessing any relevant wholesale electricity market. This is because the product markets identified likely capture the differences in requirements that the different customers may have (ie, the generators, independent retailers, and customers).[116]

Temporal dimension

140. A temporal dimension of market definition was raised as potentially relevant to our assessment of market definition because of the way electricity prices can spike throughout the day due to high consumer demand during peak hours (morning and evening) and super peak hours (those periods of the day that typically have the highest demand, carrying the highest electricity prices).[117] This contrasts with baseload which is the minimum amount of electricity needed across the whole day. In addition to this, there is 'intermittency risk' (eg, when the wind stops blowing for a few days)[118] and 'dry year risk' (when cover is needed for several weeks).[119]

141. We do not consider that a temporal dimension would materially affect our assessment of the Proposed Arrangements. In addition, we consider that while demand and the types of generation assets used may vary at different times, the underlying market mechanisms are the same, and parties manage this variation using their hedging strategies. Accordingly, we do not propose to consider this further for the purposes of our assessment of the Proposed Arrangements.

Telecommunications and broadband markets

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143. We agree that broadband/telecommunications markets are distinct from the supply of physical electricity or hedges because they involve different products, different

116 *Contact/Manawa* at [80]-[83].

117 [ ]

118 This intermittency risk has been referred to by Market Development Advisory Group (**MDAG**), the EA and the Commission as the majority of new renewable generation capacity will be intermittent generation. In order for the system to balance supply and demand over the course of hours, days, weeks and months, this intermittent generation must be firmed so that the peaks and troughs of generation can be aligned with those of demand (at a system level). MDAG "Price discovery in a renewables-based electricity system: Final Recommendations Paper" (11 December 2023) EA <www.ea.govt.nz>. EA "Generation investment pipeline" (16 September 2025) <www.ea.govt.nz>. *Contact/Manawa* at [37]-[40].

119 [ ]

120 [ ]

121 [ ]

infrastructure ownership and regulation, different pricing structures, and different market characteristics, even though they both have some common retail competition.

Conclusion on market definition

144. While we have not concluded on the relevant market(s), for the purposes of our analysis we consider that there are likely separate national markets for the wholesale supply of physical electricity and electricity hedge contracts. We consider that these markets adequately capture the competitive dynamics of the Proposed Arrangements, and our assessment is premised on this basis.

145. We agree that telecommunications and broadband markets are distinct from the supply of physical electricity or wholesale supply of hedges but have not considered it necessary to precisely define each.

146. We have not considered it necessary for the purposes of assessing the Proposed Arrangements to reach a view on whether there are separate customer and temporal dimensions of the relevant market(s).

With and without the Proposed Arrangements

147. As noted above, to determine whether the benefits and detriments identified by the Applicants are specific to the Proposed Arrangements, we assess:

    147.1. what is likely to occur in the future with the arrangement (the factual); and

    147.2. what is likely to occur in the future without the arrangement (the counterfactual).

148. We have considered all submissions and evidence received so far on what is likely to occur in the future with (factual) and without (counterfactual) the Proposed Arrangements.

149. In this context the Commission is necessarily engaging in a future-focussed assessment. As such, there is scope for there to be a range of potential factuals and counterfactuals.

150. The Commission must consider all "likely" factual and counterfactual scenarios in order to identify all the likely benefits and detriments relevant to its authorisation assessment.[122]

151. For the "likely" threshold to be met, Courts have held that there must be a real and substantial chance of the factual or counterfactual arising.[123] It must be more than a mere possibility but that need not be more likely than not.[124] However, Courts have also observed that, inherently, the factual and counterfactual are "necessarily

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122 Authorisation Guidelines at [44] and [45].

123 *NZME Ltd v Commerce Commission* at [86(a)], citing *Port Nelson v Commerce Commission* [1996] 3 NZLR 554 (CA) at 562-563.

124 *NZME Ltd v Commerce Commission* at [86(a)], citing *Port Nelson v Commerce Commission* [1996] 3 NZLR 554 (CA) at 562-563.

incapable of accurate assessment."[125] As such, there is no legal burden or evidential standard of proof for the Commission to be satisfied that factual or counterfactual scenarios and the benefits and detriments arising from them are likely.[126] For the Commission to be satisfied, it simply needs to have made up its mind on all the material before it.[127]

The situation with the Proposed Arrangements

152. The factual in the assessment of an authorisation application is the future with the conduct for which authorisation is sought. Here, that involves the Applicants entering into and giving effect to the Proposed Arrangements.

153. The Applicants submit that, with the Proposed Arrangements, Genesis will invest in the operating expenditure and capital expenditure to recertify Unit 2 and ensure it remains in the market, and provide each of the Counterparties with a financial hedge.[128] Interested parties did not disagree with this view.

Applicants' submissions

154. The Applicants further submit that in future with the Proposed Arrangements:[129]

    154.1. there will be commercial incentives for Genesis to make more capacity available to the market than without the Proposed Arrangements;

    154.2. energy security will be delivered across dry winters while New Zealand pursues net zero carbon emissions by 2050; and

    154.3. more firming options and hedge products will be available compared with the counterfactual, which will advance downstream retail competition.

Interested parties' submissions

155. Some interested parties have told us that with the Proposed Arrangements:

    155.1. the dominant market power they consider is held by the Gentailers will be further entrenched due to the certainty the Gentailers will have in being able to access firming capacity on the terms of the Proposed Arrangements;[130]

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125 *NZME Ltd v Commerce Commission* at [85], citing *Woolworths Ltd v Commerce Commission* (2008) 8 NZBLC 102,128 at [113].

126 *NZME Ltd v Commerce Commission* at [86(c)], citing *Z v Dental Complaints Assessment Committee* [2008] NZSC 55 at [96] per Elias CJ and [96] per Blanchard, Tipping and McGrath JJ.

127 *NZME Ltd v Commerce Commission* at [86](c)], citing *Z v Dental Complaints Assessment Committee* [2008] NZSC 55 at [26] per Elias CJ and [96] per Blanchard, Tipping and McGrath JJ.

128 Application at [1.9].

129 Application at [1.10].

130 Submission from Pulse Energy (26 August 2025) at 2. [
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155.2. the terms of the Proposed Arrangements being agreed to by the Applicants gives rise to a further information asymmetry between the Gentailers and the smaller independent retailers with regards to hedge products;[131] and

155.3. although the Application states that the Counterparties are not precluded from on-selling capacity obtained under the option and Genesis will offer remaining capacity to interested parties,[132] interested parties are generally sceptical that this on-selling of capacity to them will occur on terms they are able to agree to (eg, due to the shape or price of the hedge).[133] They consider that there remains uncertainty as to whether they will have access to firming capacity with the Proposed Arrangements.[134]

Our assessment

156. Our provisional view is that, with the Proposed Arrangements, Genesis will invest in the recertification of Unit 2 such that it remains operational for the duration of the Proposed Arrangements.

157. The benefits and detriments identified by the Applicants and interested parties will be discussed in detail as part of our assessment of benefits and detriments.

The situation without the Proposed Arrangements

Summary

Shutdown of Unit 2 (potential counterfactual 1)

158. The Applicants submit that, in the absence of the Proposed Arrangements, Unit 2 will be retired in January 2026 and the capacity offered by Unit 2 will not be available to the market.[135]

159. As set out in more detail below, we provisionally accept Genesis' submission that it is not commercially rational for it to keep Unit 2 open unless it enters sufficient arrangements that enable it to underwrite the necessary investment to keep Unit 2 in the market.

160. We are provisionally satisfied that, in the absence of the Proposed Arrangements, there is a likely counterfactual in which Genesis would follow through with its publicly stated plans to shut down Unit 2, as submitted by the Applicants.

131 Submission from Haast Energy (13 August 2025) at 3. Submission from emhTrade (1 September 2025) [Public] at 4-8. Submission from Pulse Energy (26 August 2025) at 2. Submission from Electric Kiwi (27 August 2025) at [10]-[11].

132 Application at [5.4(j)-(k)].

133 Submission from Haast Energy (13 August 2025) at 2. Submission from Lodestone (27 August 2025) at 1. Submission from Electric Kiwi (27 August 2025) at [45].

134 Submission from Haast Energy (13 August 2025) at 3. Submission from Lodestone (27 August 2025) at 1.

135 Application at [7.1].

Bilateral arrangements (potential counterfactual 2) and multilateral arrangements (potential counterfactual 3)

161. We have also assessed whether other likely counterfactuals exist in which Genesis would keep Unit 2 open and either:

    161.1. pursue bilateral arrangements for Huntly-backed firming options to underwrite the necessary investment to keep Unit 2 open; or

    161.2. pursue a multilateral arrangement with a broader range of potential counterparties, for example, financial intermediaries,
    [
    ].[136]

162. We provisionally accept that the Proposed Arrangements set out the minimum terms Genesis has determined it requires to keep Unit 2 in operation. Accordingly, we consider that in order to be a 'likely' counterfactual, any multilateral or bilateral arrangements must offer Genesis the same or similar certainty and financial incentives as the Proposed Arrangements. Accordingly, they must broadly be entered on the same or similar terms as the Proposed Arrangements.

163. In relation to bilateral arrangements:

    163.1. Several parties told us that they would be indicatively interested in entering arrangements with Genesis on a bilateral basis.[137] However, we provisionally consider that it is unlikely that a series of bilateral arrangements will yield contracts that offer Genesis the same level of financial assurance and certainty as the Proposed Arrangements. The terms of the Proposed Arrangements are materially more onerous for the Counterparties than previous HFOs and MSOs. The evidence we have received to date suggests that it is unlikely that any interested parties outside of the Counterparties would be prepared to accept those terms.[138]

    163.2. In addition,
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    ][139]

    163.3. Because we do not consider it likely that enough parties will bilaterally accept the terms that Genesis requires to keep Unit 2 operational, we provisionally do not consider this to be a 'likely' counterfactual.

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164. In relation to multilateral arrangements:

164.1. We do not consider there to be a real chance that parties outside of the Counterparties are likely to accept the terms Genesis has determined that it requires to keep Unit 2 operational, even on a multilateral basis.

164.2. While some parties have told us they would consider joining a multilateral arrangement [ ],[140] based on the evidence we have received to date, we do not consider there to be a real chance that these parties would accept the terms required by Genesis.[141]

164.3. We therefore also provisionally consider there is no likely counterfactual in which Genesis enters a multilateral arrangement with a broader range of potential counterparties.

165. We also provisionally accept Genesis' submission that it will be difficult to conclude bilateral or wider multilateral arrangements for Huntly-backed firming options within the timeframes Genesis requires to recertify Unit 2 for winter 2026. We understand that it is not possible for Genesis to delay recertification and secure energy supply for winter 2026. We understand that the Health and Safety in Employment Act 1992 and associated WorkSafe Approved Code of Practice prohibit Genesis from operating Unit 2 for winter 2026 without prior recertification.[142]

166. Accordingly, we consider that there is only one 'likely' counterfactual, in which Genesis would follow through with its publicly stated plans to shut down Unit 2.

167. We expand our reasoning in respect of each of these points below.

Potential counterfactual 1: Shutdown of Unit 2

Genesis' submissions- shutdown of unit 2

168. As noted above, Genesis submits that, without the Proposed Arrangements, Unit 2 will be retired in January 2026. [143] Genesis does not require Unit 2 to meet its own contractual commitments and,
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].[144]

169. To stay operational, Genesis has indicated that Unit 2 requires approximately [ ], as well as ongoing capital and operating expenditure,

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140 [ ] [ ]

141 [ ] [ ] [ ]

142 Section 20 of the Health and Safety in Employment Act 1992. WorkSafe Approved Code of Practice for the Design, Safe Operation, Maintenance and Servicing of Boilers 1996.

143 Application at [1.6], [3.12]-[3.13] and [4.8].

144 Interview with Genesis (21 August 2025) at [12.1]. Genesis Board Paper "Huntly Strategic Energy Reserve: For Approval" (June 2025) at [3.1].

to recertify it and bring it to the standard of the other Rankine Units until 2035.[145] This means that a significant volume of hedge contracts are required to financially incentivise Genesis to cover the fixed costs of the Rankine Units.[146] Accordingly, the cost of recertifying Unit 2 for Genesis' own use alone is not economic; it requires other industry participants to underwrite this cost.

170. Genesis submits that bilateral offers for Huntly firming capacity prior to the Proposed Arrangements have not had a historically high uptake,[147] and that bilateral arrangements with third parties for firming capacity would not provide it with sufficient certainty to make the necessary investment to continue to operate Unit 2.[148]

Interested parties' submissions - shutdown of unit 2

171. Some submitters expressed the view Genesis is not likely to close Unit 2 even if the Proposed Arrangements do not proceed.[149] For example, [ ] told us that it considers that Genesis will maintain Unit 2 for at least another five years because there are no realistic alternatives in the short to medium term.[150]

172. Other parties expressed scepticism that it is uneconomic for Genesis to continue to operate Unit 2 given the tight supply conditions for other thermal-backed generation (specifically, the gas shortage) and limited additional firming capacity coming into the market.[151]

Our assessment - shutdown of unit 2

173. Genesis' submission that it is incentivised to close Unit 2 in the absence of entering a sufficient number of hedges is supported by contemporaneous evidence that Genesis provided to the Commission. For example:

    173.1. A number of Genesis' internal documents between 2018 and 2021 emphasised the need to enter into a sufficient number of arrangements to underpin the viability of the Rankine Units, or to transition them out if sufficient arrangements could not be reached.[152] These documents also noted that there is a misalignment between Genesis and other parties regarding the amount of money that Genesis required to keep the Rankine Units operational versus parties' expectations as to the amount they should pay in annual premiums under any Huntly-backed firming arrangements. The documents noted that, "once all avenues for additional payments have been exhausted, Genesis will

145 Application at [1.5]-[1.6] and [1.9]. Genesis Board Paper "Huntly Strategy Energy Reserve: For Approval" (June 2025) at [3.3].

146 Application at [1.9]. Genesis Board Paper "Huntly Strategy Energy Reserve: For Approval" (June 2025) at [3.3]-[3.5] and [3.16].

147 Application at [4.10]. Genesis response to RFI dated 1 September 2025 (6 September 2025) at [1(a)(ii)].

148 Application at [4.5]-[4.10].

149 Submission from Pulse Energy (26 August 2025) at 2. Submission from 2degrees (27 August 2025) at 2. Submission from Electric Kiwi (27 August 2025) at [5] and [25]-[28].

150 [ ]

151 Submission from Pulse Energy (26 August 2025) at 2. [ ]

152 See for example Genesis Board Paper "Huntly Backup Strategy: For Approval" (December 2021) at [3.15]. Genesis Board Paper "Pillar 4: Huntly Backup Strategy" (December 2021) at 4.

consider transitioning unprofitable units [Rankine Units] out of the portfolio."[153]

173.2. Genesis updated Transpower's Planned Outage Coordination Process Portal on 29 June 2023 to reflect the closure of Unit 2 from 26 January 2026.[154]

173.3. A February 2023 Board paper noted that Genesis [ ] and that the limited uptake of MSOs did not adequately compensate thermal generation. It noted that a report prepared for Genesis by Sapere concluded that recovering the costs associated with retaining Unit 2 was not possible via the spot market. The paper indicated that Genesis would announce that Unit 2 would be decommissioned at the end of its certification period.[155]

173.4. A paper prepared for the Board in June 2025 concluded that the value of Unit 2 to the wider sector for security of supply is higher than its value to Genesis in terms of Genesis' own portfolio and meeting its own contractual commitments. It noted that [ ] are needed,[156] with only 85 MW entered into to date.[157] The paper noted that the Proposed Arrangements underwrite the investment needed (with 150 MW of Core Capacity and an additional 75 MW of Additional Baseload Capacity accounted for via the Counterparties' options under the HFO HSER, as well as the possibility of selling additional MW via HFOs to third parties). The paper further indicated that, in the absence of the Proposed Arrangements, Genesis "expect[s]" that Unit 2 will be retired from January 2026.[158]

174. The Commission observes that there is an external perception that, given the constrained electricity supply, particularly in dry winters, it must be economically rational for Genesis to continue to operate the Rankine Units for the foreseeable future. However, based on the evidence the Commission has received, the Commission is provisionally satisfied that the economic incentives on Genesis if it does not enter sufficient hedge arrangements weigh in favour of the closure of Unit 2, particularly given Genesis does not require Unit 2 to support its own customers and hedge contracts.

153 Genesis Board Paper "Huntly Backup Strategy: For Approval" (December 2021) at [3.27].

154 Transpower "POCP – Outage: HLY_2" (29 June 2023) <www.customerportal.transpower.co.nz>. Genesis response to RFI dated 20 August 2025 (9 September 2025) at [3.3].

155 Genesis Board Paper "Wholesale Markets and Huntly Update: For Discussion" (February 2023) at [3.7] and [3.22].

156 Genesis Board Paper "Huntly Strategic Energy Reserve: For Approval" (June 2025) at [3.4].

157 Genesis, NZX Market Release (12 August 2024) <https://media.genesisenergy.co.nz/genesis/investor/2024/huntly_firming_options_august_2024.pdf>.

158 Genesis Board Paper "Huntly Strategic Energy Reserve: For Approval" (June 2025) at [3.4].

175. We note that some interested parties have suggested that, faced with the shutdown of Unit 2, the Government will directly intervene to prevent the closure of Unit 2.[159] These parties suggest that this is a consideration the Commission should take into account in assessing the likelihood of a counterfactual where Unit 2 is shut down.

176. The Commission acknowledges that, following winter 2024, there was strong political interest in ensuring security of supply and energy affordability. The Applicants' negotiations for the Proposed Arrangements began as a consequence of political pressure in light of the security of supply issues arising from winter 2024,[160] and Genesis' June 2025 Board Paper notes that there is "increasingly strong political sentiment against" an outcome in which Unit 2 closed.[161]

177. However, there is insufficient evidence to find that there is a real chance of political intervention (of any nature) to prevent the closure of Unit 2. The October 2024 Government Policy Statement (**GPS**) suggests that such intervention is unlikely. In the GPS, the Government regards wholesale buyers and sellers of wholesale electricity as responsible for managing security of supply risks, and states "neither the Government nor the Electricity Authority nor the System Operator[162] will step in to insulate wholesale market participants from risk or to protect them from their failure to manage their own energy supply risks."[163]

178. We therefore do not consider that Government intervention to prevent the shutdown of Unit 2 without the Proposed Arrangements is a relevant consideration regarding the likelihood of the counterfactual that Unit 2 is shut down absent the Proposed Arrangements.

179. For these reasons, the Commission considers that, in the absence of the Proposed Arrangements, there is a 'real chance' that Genesis will shut down Unit 2 in accordance with its publicly stated plans. Accordingly, we accept it as a 'likely' counterfactual.

Potential counterfactual 2: Bilateral arrangements for Unit 2 capacity

180. We have also assessed whether there is a likely counterfactual in which, in the absence of the Proposed Arrangements, Genesis enters and gives effect to bilateral arrangements to underwrite Unit 2.

181. In such a scenario, interested purchasers would compete to acquire Huntly-backed firming capacity from Genesis. Genesis would then underwrite Unit 2 on the basis of a

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159 [ ] [ ] [ ] [ ] [ ] [ ]

160 Interview with Genesis (21 August 2025) at [2.1] and [36.1].

161 Genesis Board Paper "Huntly Strategy Energy Reserve: For Approval" (June 2025) at [3.1]-[3.5].

162 Transpower is the System Operator. In its role as System Operator, Transpower operates the wholesale electricity market and manages system security.

163 New Zealand Government "Statement of Government Policy to the EA under section 17 of the Electricity Industry Act 2010: New Zealand electricity industry" (October 2024) at [21].

series of hedge contracts between two counterparties on differentiated terms, rather than a multilateral agreement involving a number of parties all agreeing to the same terms.

Applicants' submissions - bilateral arrangements for unit 2 capacity

182. Genesis submits that entering into and giving effect to bilateral arrangements for Huntly-backed firming capacity is not a likely counterfactual. In particular, Genesis notes that:[164]

182.1. it needs to enter [ ] of hedge contracts in order to adequately cover the fixed costs of the Rankine Units;[165]

182.2. the volume and investment Genesis requires can only be secured within the necessary timeframe by the arrangements being entered into multilaterally;[166]

182.3. other potential counterparties are unlikely to accept terms of the duration and magnitude necessary to secure the future of Unit 2. Prior MSOs/HFOs did not have a sufficiently high uptake on terms acceptable to Genesis.[167] Only 85 MW of HFOs were secured by market participants for 2025, despite Genesis receiving bids totalling 270 MW,[168] because the other bids did not meet its expectations as to the requisite price.[169]

182.4. It will not be able to enter into a sufficient number of bilateral agreements in time to make the investment to recertify Unit 2 for winter 2026.[170]

183. Accordingly, Genesis submits that a counterfactual in which bilateral arrangements are entered into is not likely.

184. The Counterparties broadly supported Genesis' submission that it would have been difficult to achieve the effect of the Proposed Arrangements bilaterally:

184.1. [

]171

184.2. [

164 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 3-4. For further detail see paragraph 169.
165 Annexure 3 at [1.5].
166 Annexure 3 at [1.15]-[1.18].
167 Annexure 3 at [1.15].
168 Genesis "Genesis Energy confirms 85 MW of Huntly Firming Options" (12 August 2024) <www.genesisenergy.co.nz>.
169 Annexure 3 at [1.15(b)].
170 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 3.
171 Contact's response to RFI dated 1 September 2025 (5 September 2025).

]172

184.3. [

]173

185. [

]174

Interested parties' submissions - bilateral arrangements for unit 2 capacity

186. Several interested parties submitted that entering a series of bilateral arrangements for Huntly-backed firming capacity would be a realistic alternative to the Proposed Arrangements. For example, Pulse suggested that Genesis could hold a competitive tender for Huntly-backed firming capacity in line with its approach to MSOs and HFOs in 2022 and 2024.[175] Electric Kiwi noted that support from market participants could take many different forms and could include continuing current arrangements and entering alternative arrangements to manage revenue risk.[176]

187. These submissions inferred that Genesis' approach to bilaterally negotiating HFOs in the past is an indicator that it can (and should) do the same in a scenario without the Proposed Arrangements.

188. A number of interested parties expressed that they would be interested in pursuing bilateral arrangements with Genesis for HFOs absent the Proposed Arrangements, although the commercial terms they were interested in differed. These parties include independent generators (such as [ ]),[177] financial intermediaries such as [ ][178] and [ ],[179] and independent retailers such as [ ], [ ], [ ], and [ ].[180]

172 Meridian's response to RFI dated 1 September 2025 (5 September 2025) at 2.
173 Mercury's response to RFI dated 1 September 2025 (5 September 2025).
174 Meridian's response to RFI dated 1 September 2025 (5 September 2025) at 2.
175 Submission from Pulse Energy (26 August 2025) at 1.
176 Submission from Electric Kiwi (27 August 2025) at [5] and [27].
177 [ ]
178 [ ]
179 [ ] [ ]
180 [ ] [ ] [ ] [ ]

Our assessment - bilateral arrangements for unit 2 capacity

189. Our provisional view is that bilateral arrangements for Unit 2 capacity is not a likely counterfactual and accordingly we do not need to factor this into our assessment of benefits and detriments. In reaching that view we have assessed the following issues:

189.1. the commercial terms that Genesis would likely require Counterparties to agree to in order for a series of bilateral arrangements to have a realistic prospect of keeping Unit 2 operational; and

189.2. whether it is likely that a sufficient number of bilateral arrangements on these terms would be entered into by interested parties. We have tested the appetite for bilateral arrangements in respect of each group of interested parties:

189.2.1. the Counterparties to the Proposed Arrangements;

189.2.2. independent retailers, independent generators, and industrial customers; and

189.2.3. financial intermediaries.

<u>Genesis' commercial requirements to keep Unit 2 operational</u>

190. As noted above in relation to counterfactual 1, we are provisionally satisfied that Genesis requires a certain level of investment within a particular timeframe to keep Unit 2 open, and that the Proposed Arrangements set out the minimum terms required to keep Unit 2 in operation.

191. The weight of evidence we have received demonstrates that Genesis' expectations as to the level of risk that Counterparties should take on under the Proposed Arrangements are an order of magnitude greater than under prior HFOs and MSOs. These expectations were recorded in Genesis' internal documents,[181] and some Counterparties supported the suggestion that there were a number of terms which they would have preferred were more commercially balanced, but that Genesis required as a bottom line.[182]

192. We note that some interested parties expressed the view during consultation that Genesis' commercial requirements to retain Unit 2 are too onerous and its expectations transfer an unreasonable level of risk and cost.[183] However, Genesis' risk appetite and commercial position is a matter for Genesis, not the Commission, to determine.

193. Accordingly, we provisionally consider that in order to conclude that there is a real chance that Genesis would enter bilateral arrangements to keep Unit 2 open, we would need to be satisfied that it is likely Genesis could enter bilateral arrangements

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181 For further detail, see paragraph 173.1.

182 [ ]

183 [ ] [ ]

that offer Genesis similar certainty and financial incentives as the Proposed Arrangements, and that such arrangements could be negotiated within the requisite timeframe to recertify Unit 2 for winter 2026. In other words, enough parties would need to be likely to enter into bilateral arrangements with Genesis on the same or similar terms to the Proposed Arrangements.

Are bilateral arrangements likely to be entered into by a sufficient number of parties?

194. As noted above, during consultation, we heard that a number of interested parties would be interested in purchasing Huntly-backed firming capacity bilaterally on terms that would be suitable to their needs.[184] These included the Counterparties, independent retailers and generators, industrial customers, and financial intermediaries.

195. However, the Commission's assessment is that the terms that these parties indicated they would be willing to sign up to would not meet Genesis' requirements to keep Unit 2 operational. It is unlikely that these parties would be interested in taking on the level of risk that would offer Genesis the same certainty as the Proposed Arrangements. We expand on each of these parties in more detail below.

196. We note that even if it were possible to enter sufficient bilateral arrangements to justify keeping Unit 2 open, negotiations for any such arrangements would likely take a substantial amount of time and would be highly unlikely to conclude within the necessary timeframe to recertify Unit 2 for Winter 2026.

Would the Counterparties enter into bilateral arrangements?

197. We considered whether the Counterparties (ie, the other Gentailers) would have entered into bilateral contracts of the size and magnitude of the Proposed Arrangements.

198. As noted above, some counterparties indicated they would have entered into the Proposed Arrangements bilaterally. However,
[
].[185] Accordingly, in order for Genesis to achieve the requisite MW of hedge contracts, [ ] capacity would need to be made up by additional bilateral counterparties.

Would independent retailers, generators and industrial customers enter into bilateral arrangements?

199. During consultation, it was clear that the types of bilateral arrangements that independent retailers, independent generators, and industrial customers were

[184] See for example Submission from Lodestone (27 August 2025) at 1. [ ] [ ] [ ] [ ] [ ] [ ] [ ] [ ]

[185] [ ]

interested in were very different to terms agreed between Genesis and the Counterparties to the Proposed Arrangements.

200. These parties overwhelmingly told us that prior HFOs and MSOs had not been suitable for their needs. They would be interested in less complex or more standardised arrangements with fewer risks than prior HFOs and MSOs.[186] However, as noted above, the Proposed Arrangements are more onerous, complex and risky for counterparties than prior HFOs and MSOs. The Proposed Arrangements are therefore even less likely to be suitable for the needs of these parties. We provisionally consider that these parties can be ruled out as realistic bilateral counterparties to arrangements that would enable Genesis to underwrite the ongoing operation of Unit 2.

Would financial intermediaries enter into bilateral arrangements?

201. Financial intermediaries are firms that participate in electricity markets by buying and selling hedge contracts, but do not physically generate or consume electricity. Financial intermediaries play an important role in electricity markets, including by providing liquidity for hedge contracts (helping to ensure there are always contracts available to buy and sell) and by repackaging hedge contracts to suit the needs of smaller parties.

202. As noted above, some pre-existing holders of HFOs, such as financial intermediaries indicated that they would be interested in entering Huntly-backed firming contracts and accordingly, on the face of it, they presented the most likely group to participate in bilateral arrangements.

    202.1. [ ] told us that it is interested in 20 MW.[187]

    202.2. [ ] told us that is interested in discussing the purchase of 20-50 MW.[188]

    202.3. [ ] indicated that it had approached Genesis about being part of the negotiations for the Proposed Arrangements.[189] [ ] told us it is interested in up to 50 MW, demonstrated by its historic purchase of similar products.[190]

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186 [ ] indicated that it had previously participated in Genesis' offers but had not made it to the final stage because the offer was too complex for its needs. It would be interested in less complex peak options on a shorter-term basis. [ ] [ ] told us that whether it would be interested in bilateral agreements would depend on whether the terms of the agreements were structured for smaller players and pricing reflected the risk each party was reasonably taking. It expressed concerns about outage risks. [ ] [ ] indicated that it would be interested in a simpler synthetic risk management arrangement with a fixed strike price. [ ] [ ] indicated that it would be interested in something less complex than the HFOs. [ ] also stated that the HFOs were overly complex and onerous. [ ]

187 [ ]

188 [ ]

189 [ ]

190 [ ]

203. However, we note that these expressions of interest were based on publicly available information about the terms of the Proposed Arrangements. All parties reasonably noted that they could not make a firm decision about whether they would enter such an arrangement without further detail about the terms and conditions of the Proposed Arrangements. Because we were unable to provide the full terms of the Proposed Arrangements and seek a clear view as to whether financial intermediaries would be interested in commercial discussions on the precise terms of the Proposed Arrangements, the Commission has made its assessment by seeking to understand the risk appetite and commercial needs of these parties.

204. While financial intermediaries have the financial ability to bear more risk than many other interested parties, on balance the evidence that we have received to date demonstrates that a number of terms required by Genesis in order to retain Unit 2 are likely to be unattractive to them.

205. We have carefully weighed the evidence that we have received about the financial intermediaries' risk appetites and needs. On balance, the Commission's assessment is that while financial intermediaries might reluctantly consider accepting some terms, we consider that the combined effect of these terms overall would likely be to rule out financial intermediaries as likely counterparties. These terms include (but are not limited to):

    205.1. **Duration of the agreement**. The Proposed Arrangements have a duration of 10 years with the option to exit after five years. For parties without their own generation assets, the 10-year duration introduces significant uncertainty and risk because it is a long time to commit to a particular price where market conditions are forecast to change. The current outlook is subject to a lot of uncertainty, which makes long-term hedges even riskier.[191]

    205.2. However, exercising the exit option comes with an early exit fee of four years' worth of premiums. The early exit fee is onerous and unattractive, and for most purchasers outside of the Applicants is an unrealistic 'exit' option. Only a party with a significant generation portfolio could offset the cost of the penalty.

    205.3. Financial intermediaries expressed the view that a duration of this length was unattractive.[192] For example, [ ] indicated that it would prefer something shorter with an extension,[193] and would sign up to a ten-year product only if no other options were available.[194] In respect of

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191 The generation development pipeline is signalling a significant increase in supply over the next 3-4 years but little confirmed investment further out. This could put downward pressure on spot market prices in the near term. However, forecasts of demand vary significantly over the next 10 years. Depending on the pace of electrification, some forecasts see energy demand increasing by between 19% and 53% by 2035. Accordingly, spot pricing in the future is very uncertain. For further information see Concept Consulting "Generation investment survey: 2023 update" EA (2023) <www.ea.govt.nz>. MBIE "Electricity Demand and Generation Scenarios (EDGS)" (6 March 2025) <www.mbie.govt.nz>.

192 [ ] [ ]

193 [ ]

194 [ ]

[

].[195] [ ] indicated that it would need to be careful about tenure, and would consider an agreement with a five year renewal option.[196] It indicated that the early exit fee of the Proposed Arrangements did not seem a very compelling option to exercise.[197] Some financial intermediaries also expressed some concern about signing up to a particular fixed price, taking into account how market conditions and power prices might evolve in the next ten years.[198]

205.4. **Premium**. Whilst not directly comparable, the premium costs agreed under the Proposed Arrangements are higher than Genesis' previous MSO and HFO products,[199] and exceed the level of premiums previously agreed with financial intermediaries by a [ ]. The market clearing premium for HFOs in 2024 was [ ].[200]
[
]201 Generally speaking, we understand that counterparties to hedge contracts would expect premiums to be discounted when the hedge contract lasts for a substantial period of time to reflect the risk of electricity prices changing due to changing market conditions (whereas 1-2 year contracts, such as prior MSOs and HFOs, would be priced at a higher premium).

205.4.1. The specifics of the premium were not able to be disclosed to financial intermediaries, but some financial intermediaries had generally expressed reservations about the premiums payable in light of the other terms of the contract. For example, [ ] and [ ] indicated that if the terms of the contract substantially transferred suspension risks to the counterparties, they would expect to see these reflected in lower premiums.

205.5. **Premium adjustments**. In addition, we note that the 2024 HFOs included a CPI adjustment for the premium but otherwise fixed costs were firm. The annual premium is subject to a reset at year 5, together with components increasing annually and other clauses which may result in other adjustments.[202]
[

195 Genesis response to RFI dated 20 August 2025 (9 September 2025) at 6.
196 [ ]
197 [ ]
198 [ ]
199 Application – Additional Information.
200 Genesis' response to RFI dated 20 August 2025 (9 September 2025) at Annex 1.
201 Applicants "Strategic Energy Reserve – Huntly Firming Option: Term Sheet" (18 June 2025) (**Term Sheet**) at 2.
202 Application at [5.4(b)].

]203 This makes the premium component subject to risk of significant, unforeseeable increase and is unlikely to be appealing to parties seeking price certainty in their hedging arrangements. The specifics of these terms were not able to be disclosed to financial intermediaries and so we were unable to seek their comment on it.

205.6. **Notional cost of coal**. As with the 2024 HFO, the fixed price of the Proposed Arrangements is linked to the notional price of coal. This leaves the purchaser of the deal **open** to the risk of increases in coal price.

205.6.1. Interviews with interested parties have highlighted that a number of parties (including some financial intermediaries) did not progress with previous HFO offers as they were unable to manage the coal price risk.[204]

205.7. **Suspension events**. The Proposed Arrangements include a detailed suspension event regime, setting out the circumstances **in** which Counterparties' rights to exercise an option will be cancelled or curtailed.
[

]205
Comparatively, prior HFOs had a suspension event threshold of a 25 MWh reduction in generation capacity, but these suspension events only reduced parties' call capacity (rather than cancelling the right to exercise an option entirely) unless a 50 MWh reduction in generation capacity threshold was met.[206] Parties without generation assets have less ability to manage suspension risks. Genesis' expectation, backed by its experience of the 2024 HFO negotiations, is that [

].[207]

205.7.1. The specifics of these terms were not able to be disclosed to financial intermediaries and so we were unable to seek their comment on it. However, financial intermediaries raised concerns about how plant outage risks would be shared between Genesis and any contract holder. [ ] noted that these were of critical importance to the quality of the contract. If Genesis was putting all plant risk on [ ] as

203 Term Sheet at 2 and 26-27.

204 [ ] [ ] [ ] [ ] [ ]

205 Term Sheet at 9-14.

206 Genesis "Huntly Firming Options" (May 2024) <www.media.genesisenergy.co.nz> at 11.

207 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 4-5.

buyer, [ ] expects the premium to reflect that.[208] However, these risks are not mitigated by lower premiums.

206. Outside of these contract terms, financial intermediaries also variously noted that:[209]

206.1. They would expect the allocation of risk onto the Counterparties and the quality of contract terms to affect the premium price (downward).

206.2. The efficiency modifiers, running profiles, and nomination lead times of the Proposed Arrangements would be likely to favour cost over flexibility due to the Applicants' abilities to be flexible through the rest of their portfolios. However, [ ] indicated that it would value flexibility over cost. This would have a 'critical influence' on the attractiveness of any hedge products to it.

207. For the above reasons, we consider that there remains too much uncertainty as to whether financial intermediaries will be willing or able to enter bilateral arrangements on Genesis' required terms. We consider that if further information about these terms was released to these parties, the likelihood that they would remain interested in entering bilateral arrangements on these terms would decrease, not increase. Accordingly, we do not consider that there is a 'real chance' that there is a likely counterfactual in which these parties entered into bilateral arrangements with Genesis.

208. For completeness, we note that these terms would also rule out independent generators, independent retailers, and industrial customers but, as noted above, we understand that the entire structure of the Proposed Arrangements would be unsuitable for those parties.

<u>Conclusion on bilateral agreement - counterfactual 2</u>

209. It appears that there is a mismatch of expectations between Genesis and interested parties as to the reasonable terms of any bilateral arrangement. While there seemed to be an expectation on the part of some parties that better terms could be negotiated as part of any bilateral process,[210] as noted above, we do not consider it likely that Genesis would agree to less onerous terms proposed by interested parties, or that interested parties would be in a position to agree to the terms required by Genesis.

210. Accordingly, we do not consider that there is a 'real chance' that a series of bilateral arrangements of the magnitude and terms required by Genesis would even have been reached between Genesis and the Counterparties.

211. For the above reasons, we provisionally consider that a counterfactual in which Genesis enters a sufficient number of contracts to underwrite Unit 2 bilaterally is not

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208 [ ] [ ] [ ]

209 [ ]

210 [ ] [ ]

'likely'. In other words, on the evidence, we do not think there is a real chance that this will happen absent the Proposed Arrangements.

Potential counterfactual 3: Multilateral agreement with a greater number of parties

212. Finally, we have considered whether there is a 'likely' counterfactual in which Genesis enters into a multilateral agreement with a greater number of parties.

213. As noted at paragraph 162 above, in order to conclude that this is a 'likely' counterfactual, we would need to be satisfied that additional interested parties would enter multilateral arrangements with Genesis and the Counterparties on broadly the same terms as the Proposed Arrangements (such that Genesis would still have sufficient certainty to keep Unit 2 operational). In other words, this potential counterfactual would involve arrangements similar to the Proposed Arrangements, just with the inclusion of additional counterparties.

Applicants' submissions - multilateral agreements, counterfactual 3

214. Genesis, Contact and Mercury have indicated that they would have entered into multilateral arrangements with additional parties, although they expressed doubt that practically this could have been done in the time available.[211]

215. Similarly, Meridian indicated that it would have entered into the Proposed Arrangements if the arrangements were extended to additional parties. Meridian, however, considered it unlikely that the negotiations of the Proposed Arrangements could have been concluded in the time available if additional parties had been involved.[212]

216. The Applicants also all noted that they are open to including additional counterparties in the factual once the Proposed Arrangements have been authorised and entered into.[213]

217. We heard from market participants that a primary reason other parties have not been invited to be part the Proposed Arrangements is because it is unclear which entities, outside of the Counterparties, have the requisite balance sheets to support the Proposed Arrangements (in particular, the annual premium).[214]

Interested parties' submissions - multilateral agreements, counterfactual 3

218. As noted above in relation to counterfactual 2, some parties, primarily pre-existing holders of HFOs, such as financial intermediaries, indicated that they would be

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211 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 4. Contact's response to RFI dated 1 September 2025 (5 September 2025). Mercury's response to RFI dated 1 September 2025 (5 September 2025).

212 [Meridian's response to RFI dated 1 September (5 September 2025) at 3.]

213 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 4. Contact's response to RFI dated 1 September 2025 (5 September 2025) at [2]. Mercury's response to RFI dated 1 September 2025 (5 September 2025) at [2]. Meridian's response to RFI dated 1 September (5 September 2025) at 3.

214 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 1-2. [
]

interested in entering Huntly-backed firming contracts, including potentially on a multilateral basis with the Applicants.[215]

Our assessment - multilateral agreements, counterfactual 3

219. We have carefully assessed the information provided to us by interested parties about their ability and incentives to enter a multilateral arrangement on the terms set out in the Proposed Arrangements.

220. Our provisional view on the basis of the evidence received to date is that there is not a 'real chance' that multilateral arrangements would be agreed with a wider range of counterparties in the absence of the Proposed Arrangements. This is for the same reasons that we have set out above in relation to the possibility of bilateral contracts.[216]

221. The Counterparties are more able to manage and have a direct interest in the type of insurance that the Proposed Arrangements offer. In particular, their size and scale can make it easier to manage the risks allocated to them under the Proposed Arrangements within their generation portfolios. For example, in a suspension event, the Counterparties could fall back on their own generation and storage (for what they would hope would be for only a short duration) to manage the suspension event (ie, conceptually they have insurance against an insurance failure), whereas other interested parties are more likely to be exposed to extremely elevated spot prices during the suspension event because they do not have a fall-back position.

222. We also note that some of the financial intermediaries' interest in the multilateral arrangements appeared to be predicated in part on concern that there would not be other Huntly capacity available to purchase from Genesis.[217] However, that is not the case. The interest of these parties in multilateral arrangements may fall away given that a significant amount of Huntly-backed capacity remains uncontracted and may be offered on less onerous terms.

223. For the above reasons, we consider that there remains too much uncertainty as to whether these parties would be willing or able to enter Genesis' required terms. We consider that if further information about these terms were released to these parties, it is likely that their interest in entering the multilateral arrangements would decrease, not increase.

224. On balance, while we understand that there might be a possibility for the arrangements to occur on a broader multilateral basis such that they include other interested parties as initial counterparties, we consider this possibility to be too remote to meet the 'real chance' threshold. Subject to receiving firmer commitment from those interested parties we consulted with, we provisionally consider it unlikely that any additional parties are likely to enter into the current terms on a broader

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215 [ ] [ ]

216 See paragraphs 209 to 211.

217 [ ]

multilateral basis alongside the Applicants, irrespective of whether they have previously signed HFOs.

225. Accordingly, we have provisionally excluded a wider multilateral arrangement as a 'likely' counterfactual.

Our assessment of benefits and detriments

226. Given we consider we have jurisdiction in respect of section 58(1)-(2) of the Act, the Commission will grant authorisation if it is satisfied, on the evidence before it, that the proposed conduct will result, or will be likely to result, in a benefit to the public which would outweigh the lessening in competition that would result or be likely to result.[218] In making this assessment, the Commission considers the evidence and makes judgements about how much weight to give to the evidence.

227. In *Godfrey Hirst*, the Court of Appeal observed that the Commission must consider a broad range of benefits and detriments in applications for authorisation. This may include efficiencies and non-economic factors.[219]

228. In particular, the Court of Appeal indicated that the Commission must have regard to efficiencies when weighed together with long-term benefits to consumers, the promotion of competition, and any economic and non-economic public benefits. The Court stated that "[w]here possible these elements should be quantified; but the Commission and the courts cannot be compelled to perform quantitative analysis of qualitative variables."[220]

229. The Commission's approach is to quantify benefits and detriments to the extent that it is practicable to do so.[221] Regarding the weight that can be given to qualitative factors, the Court of Appeal said in *Godfrey Hirst* that "[q]ualitative factors can be given independent and, where appropriate, decisive weight."[222]

Potential benefits

Summary

230. As noted above, we have assessed the potential benefits of the Proposed Arrangements against what we currently consider to be the only likely counterfactual, in which Unit 2 is shut down and its capacity is removed from the market.

231. Against that backdrop, we are of the preliminary view that the key benefits resulting from the Proposed Arrangements are:

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218 Section 61(6) of the Act. Authorisation Guidelines at [18.2].

219 *Godfrey Hirst NZ Ltd v Commerce Commission* [2016] NZCA 560 (CA) at [24] and [31].

220 *Godfrey Hirst NZ Ltd v Commerce Commission* [2016] NZCA 560 (CA) at [36].

221 *Telecom Corporation of New Zealand Ltd v Commerce Commission* [1992] 3 NZLR 429 (CA) at 447. *Air New Zealand and Qantas Airways Limited v Commerce Commission* (2004) 11 TCLR 347 (HC) at [319]. *Ravensdown Corporation Ltd v Commerce Commission* High Court, Wellington API68/96 (16 December 1996) at [47] to [48].

222 *Godfrey Hirst NZ Ltd v Commerce Commission* [2016] NZCA 560 (CA) at [38].

231.1. improved security of supply, particularly during 'dry' winters;

231.2. lower wholesale electricity prices (or reduced price volatility); and

231.3. greater availability of hedge contracts being offered to third parties on terms more suitable to them.

232. We consider the likelihood and magnitude of these potential benefits in more detail throughout the rest of this section.

Improved security of supply

Summary

233. The Applicants submit that the Rankine Units provide socially valuable firming capacity by supporting management of seasonal energy risks, and that maintaining the operation of Unit 2 with the Proposed Arrangements represents a public benefit.[223]

234. This submission was widely supported by interested parties and energy security modelling undertaken by Transpower. We are provisionally satisfied that this benefit will likely eventuate compared to the counterfactual in which Unit 2 is retired. In this counterfactual, the capacity of Unit 2 will be removed from the market and security of supply during dry years will be threatened.

235. Accordingly, we have provisionally placed weight on the likelihood of a public benefit arising in the form of enhanced security of supply.

Applicants' submissions

236. The Applicants submit that to maintain secure energy supply and ensure energy affordability, New Zealand requires flexible generation that can vary output to balance variations in weather while further investment is made in renewables.[224]

237. The Applicants submit that a key supply-side response to the winter 2024 issues was the deployment of additional thermal generation from the Rankine Units to cover demand in times where supply was constrained.[225] The Rankine Units provide socially valuable firming capacity to support the management of seasonal energy risks as they can be turned on in response to calls.[226] Therefore, maintaining the operation of Unit 2 with the Proposed Arrangements presents a public benefit.[227]

What measures to maintain security of supply might the Applicants take if Unit 2 is closed?

238. The Applicants provided information about what they would do to protect against dry winter risk if Unit 2 closed and they did not have access to the firming capacity. Aspects of their responses included measures to maintain security of supply, whereas

223 Application at [10.13].
224 Application at [1.1], [1.3] and [10.11]. Genesis Board Paper "Huntly Backup Strategy: For Approval" (December 2021) at [3.13].
225 Application at [1.4], [4.3] and [10.12].
226 Application at [5.4(h)] and [10.13].
227 Application at [10.12].

others relate more to managing risk. In the absence of the Proposed Arrangements, the Applicants submit that:

238.1. Each Counterparty would naturally first look to satisfy its own contractual obligations from the capacity it had available and then make independent decisions as to what capacity to offer into the market.

238.2. Each Counterparty would also continue to explore alternative firming options, but those alternatives would likely be less efficient than utilising an asset that is currently in the market, such as what would occur under the Proposed Arrangements.

239. Genesis indicated that it is able to cover its [ ] and contractual obligations with only two Rankine Units.
[

].[228]

240. Mercury submitted that in the absence of the Proposed Arrangements,
[

].[229]

241. Meridian submitted that in the absence of the Proposed Arrangements, it would
[

].[230]

242. Contact has some of its own thermal assets, and also has a battery energy storage system (**BESS**) and solar assets under construction. However, Contact submitted
[

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242.1. [ ]

242.2. [ ]

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228 Genesis' response to RFI dated 20 August 2025 (9 September 2025) at [6].

229 [

] Applicants "Annexure 5: Confidential submission by Mercury on the counterfactual" (4 August 2025) (**Annexure 5**) at 1.

230 Applicants "Annexure 6: Submission by Meridian on the counterfactual" (4 August 2025) (**Annexure 6**) at 3-4.

242.3. [ ]

242.4. [ ].[231]

243. [ ][232]

Interested parties' submissions on security of supply benefits

244. Most interested parties agreed that the Proposed Arrangements will improve energy security in the short-term as gas supply remains constrained.[233] Some parties noted that Huntly is the only short-term option available to provide firming capacity in the market at the moment.[234]

Transpower modelling on security of supply

245. The feedback received during consultation is also broadly supported by modelling undertaken by Transpower. Transpower, as the System Operator, is responsible for publishing the medium-term security of supply assessment (**SOSA**) annually. The analysis assesses whether there is enough electricity generation in the system to meet total demand across the country under a range of supply and demand scenarios over the following 10 years.

246. The 2025 SOSA shows that the New Zealand Winter Energy Margin (**NZ-WEM**)[235] falls below the lower security standard[236] by 2026 due to the reduction in expected gas supply.[237] The NZ-WEM is forecast to recover in 2027 in the reference case, which includes Unit 2. However, in the 'reduced Rankine' scenario (ie, if Unit 2 is decommissioned), the NZ-WEM remains below the lower security standard out to 2035. Transpower submits that energy insecurity is likely to continue at least for the short-term (ie, 3-5 years).[238] Transpower considers that retiring Unit 2 will further exacerbate the current energy constraints, especially in dry winter years. Transpower

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231 Applicants "Annexure 4: Confidential submission by Contact on the counterfactual" (4 August 2025) (**Annexure 4**) at 1.

232 Interview with Contact (26 August 2025) at [25.1].

233 [ ] Interview with Transpower (18 August 2025) at 4-6. Interview with the EA (4 August 2025) at 4. Submission from WEL Networks (21 August 2025) at 1. Submission from Fletcher Building (26 August 2025) at 1. Submission from Energy Resources Aotearoa (27 August 2025) at [3]. Submission from MEUG (4 September 2025) at [9]. Interview with Consumer NZ (26 August 2025) at [15.1]. Submission from Lodestone (27 August 2025) at 1. Submission from 2degrees (27 August 2025) at 1. Interview with Nova Energy (26 August 2025) at [3.1]. Interview with MEUG (25 August 2025) at 1-2.

234 Interview with Lodestone Energy (2 September 2025) at [13.1]. Interview with Nova Energy (26 August 2025) at [3.1]. Interview with Octopus (25 August 2025) at 1. Interview with Pulse Energy (22 August 2025) at [4.2]. Interview with Consumer NZ (26 August 2025) at [15.1].

235 The NZ-WEM is the difference between the expected amount of energy that can be supplied and expected demand during the period 1 April to 30 September each year expressed as a percentage of demand. The current NZ-WEM is calculated by the EA to be 14%-16% and is published in Part 7 of the Code.

236 Falling below the lower security standard means that the margin of available generation for a given year falls below 14%.

237 Transpower "Security of Supply Assessment 2025" (30 June 2025) <www.static.transpower.co.nz> at 7.

238 Interview with Transpower (18 August 2025) at 2.

also expressed the view that the Rankine Units will be needed for 10 years, if not more, to safeguard energy security.[239]

247. Transpower also publishes a monthly update of the electricity risk curves (**ERCs**), which forecast the potential risk to energy supply for the next 12-24 months, taking into account fuel availability (hydro storage, gas and coal) and the availability of generation capacity to make use of that fuel. Retaining Unit 2 mitigates the potential risk of energy shortage in winter 2026.[240] By comparison, removing Unit 2 from the market leads to the ERCs shifting upward, indicating a higher probability of not meeting demand due to increased risk of supply shortages.[241]

Our assessment of security of supply

248. Based on the views of interested parties and the energy security assessment by Transpower, we are provisionally satisfied that security of supply benefits will likely eventuate compared to a counterfactual in which Unit 2 is retired. The evidence broadly supports that, under this counterfactual, security of supply during dry winters may be threatened.

249. We do not consider that the alternative measures that the Applicants indicated that they would take to address security of supply in the counterfactual would be sufficient to negate these benefits. All Applicants noted the limited alternatives available to manage seasonal dry-year risk.[242] The Applicants indicated that they would primarily rely on existing generation investment programmes to meet the security of supply shortfall, though it was noted that consent and build time constraints limited their ability to accelerate these programmes to meet near-term risks.[243] Other options to manage security of supply are unlikely or less attractive:

    249.1. Gas-backed swaptions with other generators are unlikely to be a realistic alternative due to the lack of certainty about gas supply. Diesel-backed swaptions would come at a significantly increased cost.[244]

    249.2. Investment in alternative forms of thermal generation, such as open cycle gas turbines, would require a significant long-term increase in gas availability to be justified, and lead times are expected to be at least 3-4 years given consenting timeframes and global purchase lead times for these generating units.[245]

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239 Interview with Transpower (18 August 2025) at 3.

240 In their most recent updates, the base case ERCs have assumed that Unit 2 closes in February 2026 and a sensitivity case has been produced assuming Unit 2 is retained. Transpower "August 2025 Energy Security Outlook" (25 August 2025) <static.transpower.co.nz> at 1 and 5.

241 Transpower states in its August 2025 Energy Security Outlook that: "… *we look at the impact on the ERCs if the third Rankine Unit were to remain available in 2026, which is currently awaiting Commerce Commission approval. This lowers the NZ Watch curve by up to 680 GWh and results in no SSTs crossing any ERCs*." Transpower "August 2025 Energy Security Outlook" (25 August 2025) <static.transpower.co.nz> at 1.

242 Annexure 6 at 3. Annexure 5 at 1. Annexure 4 at 1.

243 Annexure 6 at 3. Annexure 5 at 1. Annexure 4 at 1.

244 Annexure 6 at 3.

245 Annexure 4 at 1.

249.3. Accelerating mass market retail flexibility, such as EV charging flexibility and time-of use pricing,[246] could provide some relief for high demand winter peaks, but would not reduce consumption overall. Rather, it would only time-shift consumption and is unlikely to resolve dry year energy risk.

249.4. Some Applicants could use or expand their demand response incentives with their major electricity customers to ensure security of supply.[247] However, although customers subject to demand response mechanisms may receive some financial compensation to adjust their demand, there is an opportunity cost to the economy associated with a demand-side response strategy.

250. Given the importance of security of supply to the economy, we provisionally accept that security of supply is a primary benefit arising from the Proposed Arrangements. This view is supported by almost all interested parties. Accordingly, we have placed weight on the security of supply benefit as part of our overall assessment.

251. We also consider that there are likely to be flow-on benefits associated with improved security of supply in the form of lower and more stable wholesale electricity prices (compared to a counterfactual in which Unit 2 is disestablished). We discuss these flow-on benefits below.

Lower wholesale electricity prices

Summary

252. The Applicants submit that the Proposed Arrangements will result in lower average wholesale electricity prices compared to a counterfactual where Unit 2 is retired, producing public benefits in the form of additional consumer surplus and a transfer of surplus from producers to consumers.

253. We have quantified the effect of removing Unit 2 from the market and are provisionally satisfied that the Proposed Arrangements would produce a public benefit in the form of new consumer surplus, potentially in the range of $13.5m – $15.8m over the next five years. We have placed weight on the creation of new surplus in our overall assessment of benefits.

254. The Applicants also estimate a transfer of surplus from producers to consumers and submit that this is a potential benefit. While we agree that the Proposed Arrangements would involve a transfer of surplus from producers to consumers, such a transfer reflects a reallocation of surplus within the economy rather than the creation of new surplus.

255. Accordingly, we have only placed weight on the creation of new consumer surplus, which nevertheless represents a significant benefit of $13.5 - $15.8m over the next five years.

246 Annexure 5 at 1.

247 Annexure 6 at 3.

Applicants' submissions on wholesale electricity prices

256. As a flow-on effect of greater security of supply, the Applicants submit the Proposed Arrangements will result in lower average electricity prices by inserting additional capacity into the supply stack compared to a counterfactual where Unit 2 is retired.[248] The Applicants submit that this would result in additional consumer surplus relative to the counterfactual and a transfer of surplus from producers to consumers.[249]

257. The Applicants refer to analysis by Concept Consulting which estimates that, if one Rankine Unit is removed, prices will increase by around 10% – 12% between 2026 and 2028, and will increase by 6% in the long term.[250] NERA, on behalf of the Applicants, estimates that lower average wholesale electricity prices will translate to public benefits in the forms of:[251]

    257.1. a (partial) consumer surplus benefit of $13.5m – $15.8m; and

    257.2. a transfer of surplus to consumers of $2.13b – $2.24b.

Interested parties' submissions on wholesale electricity prices

258. As part of our consultation, we sought feedback about the likelihood that the Proposed Arrangements would result in lower average wholesale prices and on NERA's estimation (on behalf of the Applicants) of the magnitude of these benefits.

259. In general, most interested parties agreed that keeping Unit 2 in the market as a result of the Proposed Arrangements will result in lower and less volatile average wholesale prices, particularly during dry years.[252]

260. Some parties were doubtful of the magnitude of public benefit expressed in the Application:

    260.1. Haast Energy noted that consumer surplus benefits would only benefit consumers to the extent that any cost savings are passed through to retail prices and hedge offerings.[253]

    260.2. [ ] expressed scepticism as to the magnitude of consumer surplus benefit claimed.[254]

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248 Applicants "Annexure 1: NERA Report prepared for Bell Gully" (4 August 2025) (**Annexure 1**) at [17].

249 Annexure 1 at [18].

250 Application at [10.15]-[10.16].

251 Annexure 1 at [30] and Table 2.

252 Submission from Transpower (26 August 2025) at [16]. Submission from Energy Resources Aotearoa (27 August 2025) at [9] and [23b]. Submission from Fletcher Building (26 August 2025) at 1. Submission from WEL Networks (21 August 2025) at 1. Interview with the EA (20 August 2025) at [3]. Interview with Octopus (25 August 2025) at 3. Interview with Nova Energy (26 August 2025) at [15.1]. Interview with Lodestone Energy (2 September 2025) at [27.1].

253 Submission from Haast Energy (13 August 2025) at 2.

254 [ ]

Our assessment of wholesale electricity prices

261. The evidence before us supports the Applicants' submission that the price setting mechanism of the New Zealand electricity market is such that, all else equal, if additional capacity is offered into the supply stack, the wholesale electricity price would fall. Therefore, against a counterfactual where Unit 2 is retired, and assuming that opportunities arise for Unit 2 to be dispatched, we agree with the Applicants that we would expect wholesale prices to on average be lower with the Proposed Arrangements.

262. To quantify these benefits, we tested NERA's assessment of the likely impact of the removal of Unit 2 on price. Key to NERA's estimates of the relevant consumer surplus benefit and any transfer of surplus to consumers are NERA's assumptions regarding how prices would evolve in the factual and counterfactual. NERA assumes that counterfactual prices would be 10% higher in year 1 and 12% higher in years 2 and 3 based on analysis by Concept Consulting.[255]

263. To test the suitability of these price scenarios, we employed an alternative approach to estimate the effect on price of removing Unit 2 from the market. We used data on actual generation from Unit 2 and the EA's price sensitivity scenarios to estimate the effect of removing Unit 2 from the market between 7 April 2023 and 4 April 2025.[256] More details on our approach and our results can be found in Attachment A.

264. We find that removing Unit 2 will result in prices being, on average, 11.8% – 13.2% higher.[257] This largely aligns with NERA's price change assumptions and so we are satisfied with NERA's estimated range for the public benefit.

265. As outlined in Attachment A, we consider there to be a range of qualitative factors and modelling limitations that affect our consideration of the appropriate range for the magnitude of this public benefit. Some of these considerations (such as our analysis period reflecting dry year conditions) suggest that we overstate the effect on price that would occur. However, other factors (such as NERA only estimating these benefits over a 5-year period) would suggest that we understate the potential public benefits.

266. On balance, we consider that these factors are likely to cancel out to some extent, and we see no reason to think that they would materially diminish the magnitude of these public benefits such that it would change our conclusions.

267. We therefore consider that the Proposed Arrangements will produce sizeable consumer surplus benefits. Even if we exclude benefits arising from any transfer of surplus from producers to consumers on the basis that this constitutes a neutral

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255 NERA considers 2 scenarios. In the first prices in years 4 and 5 are 10% and 8% higher, respectively. In the second scenario, prices are 11% and 10% higher, respectively.

256 The EA considers price sensitivity with respect to volume changing by -5%, -4%, -3%, -2%, -1.5%, -1%, -0.5%, 0.5%, 1%, 1.5%, 2%, 3%, 4%, and 5%. EMI "Sensitivity of price to changes in load" EA <www.emi.ea.govt.nz>. Due to data availability, we exclude the following dates from our analysis: 7 April 2024, 22 October 2024, 16 November 2024, and 14-21 January 2025.

257 Where 11.8% reflects a simple average, and 13.2% reflects a generation weighted average.

transfer, we consider the public benefit of the Proposed Arrangements is likely to fall in the range of $13.5m – $15.8m.

268. NERA additionally raised that the Proposed Arrangements will result in public benefits arising from a transfer of surplus from producers to consumers in the range of $2.13b – $2.24b. As discussed in Attachment A, we have placed less weight on these public benefits. Such a transfer reflects a reallocation of surplus within the economy rather than the creation of new surplus. We therefore place weight only on the creation of new surplus in our overall assessment of the Proposed Arrangements.

Improved incentive to offer hedges to third parties

Summary

269. The Applicants submit that the Proposed Arrangements will result in more hedge products being made available to third parties (ie, interested parties outside the Counterparties) compared to a counterfactual in which the capacity of Unit 2 is removed from the market.[258] The Applicants also submitted that the Proposed Arrangements improve their ability and incentive to offer these hedge contracts on terms that are better tailored to buyers' needs.[259]

270. As part of our consultation, we sought feedback about the benefits of third-party access to hedge products, as well as the likelihood and magnitude of these potential benefits in the factual. A number of parties submitted that Genesis' prior HFOs and MSOs had not been suitable for the needs of many interested parties.

271. Nevertheless, these contracts were offered prior to the HFO being in place and Genesis has stated as part of the Application that it intends to design products that are suitable for the needs of interested parties. Genesis told us that it is already engaging with independent retailers, generators, and industrial customers to understand their needs. If the certainty created by the Proposed Arrangements enables Genesis to offer hedge contracts to third parties on terms that are fair and reasonable and more suitable for their needs, this would represent a further, significant, public benefit.

272. The Commission provisionally accepts that the Proposed Arrangements provide the Applicants with the ability to offer a greater number of hedges to third parties compared to a counterfactual in which Unit 2 exits the market. We also provisionally accept that at least Genesis has a greater incentive to sell hedges backed by this capacity compared to a scenario in which Unit 2 exits the market.

273. The Commission takes note of Genesis' commitment in the Application to design products that are suitable for the needs of interested parties (such as financial intermediaries, independent retailers, generators, and industrial customers), and in making our Draft Determination we have placed weight on a public benefit arising in the form of access to hedge contracts for a broader range of participants.

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258 Application at [9.5].

259 Application at [9.5]-[9.8]. Interview with Mercury (21 August 2025) at [32.1]-[33.1].

274. The Commission expects Genesis to promptly follow through on that commitment. We expect these products to be offered on fair and reasonable terms, and to take into account that Genesis has already secured the capital and tenure it deems necessary to commit to keeping three Rankine Units in market.

What parties would benefit from access to Huntly-backed firming capacity and why?

275. Our consultation indicated that there are two broad categories of parties who would be interested in access to hedges backed by Huntly capacity. At a high level, these are:

    275.1. parties who have previously purchased or sought access to HFOs and MSOs. Outside of the Counterparties, we understand purchasers of these contracts have historically included financial intermediaries, who repackage and on-sell hedge products to other parties;[260] and

    275.2. parties for whom HFOs and MSOs have not historically been suitable, such as smaller independent generators and retailers.

276. The importance of access to Shaped Hedge contracts for the second category of parties was generally supported by independent retailers and generators during consultation.[261] Shaped Hedge contracts are important for these market participants to manage risk in the electricity sector. We also heard that challenges accessing suitable risk management products have represented barriers to entry and expansion in retail and generation markets.[262] As the electricity system becomes more reliant on intermittent generation (wind and solar), spot market pricing becomes more volatile.[263] Access to these contracts ensures that independent retailers and generators can offer products that meet their customers' needs: sustained power at a stable price. This increases competition in the market, brings more power into the system, provides more choice for consumers, and puts downward pressure on retail prices.[264]

277. The Level Playing Field Measures the EA is currently consulting on highlight the importance of access to firming for independent retailers and generators and as a potential mechanism to ensure that hedges are offered on suitable terms.[265] These measures would introduce a principles-based obligation on Gentailers to trade hedges in a non-discriminatory way. The Authority proposes to monitor trading and hold a mandatory obligation as a backstop should the principle-based obligations not result in access improvements. However, interested parties have noted that these measures are

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260 See paragraphs 197 to 211.

261 Interview with 2degrees (19 August 2025) at 3. Interview with Electric Kiwi (22 August 2025) at [6.1]. Submission from Electric Kiwi (27 August 2025) at [47]. Interview with Pulse Energy (22 August 2025) at [5]. Interview with Octopus (25 August 2025) at 3.

262 [ ]

263 MDAG "Price discovery in a renewables-based electricity system: Final recommendations paper" (11 December 2023) at [4.27].

264 Submission from 2degrees (27 August 2025) at 2. Interview with 2degrees (19 August 2025) at 1-2. Submission from Electric Kiwi (27 August 2025) at [47]. Electricity Authority "Reviewing risk management options for electricity retailers – issues paper" (7 November 2024) at [1.1].

265 EA "Level playing field measures" (May 2025) <www.ea.govt.nz>.

some time away from being implemented.[266] The EA consulted on the level playing field options in February 2025 with a further consultation on amendments to the Code planned for October 2025.

278. Based on the views of interested parties and the work currently undertaken by the EA, we consider that if the Proposed Arrangements increase the incentives of the Applicants to offer suitable hedge cover designed for the smaller interested parties, this is likely to represent a material public benefit.

Access to Shaped Hedge contracts prior to the Proposed Arrangements

279. During consultation, a number of interested parties provided information about the terms on which Genesis had offered Shaped Hedge products in the past.[267]

280. We received consistent evidence that Huntly firming capacity had been offered to the market to date in the form of MSOs and HFOs, or over-the-counter peak products.[268]

281. Genesis told us there had been limited interest outside of the Counterparties in the firming products it has offered to the market to date.[269] That does not appear to be entirely true: its 2024 HFOs were primarily purchased by financial intermediaries and not by Gentailers, and a number of interested parties, including independent retailers and smaller Gentailers indicated that they had expressed interest in these products over the years.[270] However, the submission that some third parties (such as industrial customers, independent generators, and independent retailers) have not purchased MSOs and HFOs was supported by those parties, who indicated that these products were unsuitable for them in terms of size, duration, and allocation of risk.[271] Interested

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266 Interview with 2degrees (19 August 2025) at 3. Interview with Lodestone Energy (2 September 2025) at [20]. Interview with Pulse Energy (22 August 2025) at [11] and [12]. Submission from Haast Energy (13 August 2025) at 3.

267 [ ] [ ] [ ]

268 Genesis "Genesis Energy confirms 85 MW of Huntly Firming Options" (12 August 2024) <www.genesisenergy.co.nz>. Genesis "Market Security Options" (August 2022) <www.media.genesisenergy.co.nz>.

269 Application at [9.5]. Interview with Genesis (21 August 2025) at [10]. [ ]

270 [ ] [ ] [ ]

271 [ ] Interview with 2degrees (19 August 2025) at 2. Interview with Octopus (25 August 2025) at 3. Interview with Electric Kiwi (22 August 2025) at [5.1]. Interview with MEUG (25 August 2025) at 4. Submission from MEUG (4 September 2025) at [9.2]. The submissions are supported by the work of the EA, which recently concluded that OTC super-peak hedge contract prices trade at a substantial unquantified premium over ASX baseload prices adjusted for shape. The EA concluded that "while the evidence points to scarcity being a driver, there is also a plausible driver that has competition implications (ie, refusing to supply products on appropriate terms to Counterparties who are downstream competitors), indicating that some level of market power could have been in play. EA "Reviewing risk management options for electricity retailers" (27 February 2025) <www.ea.govt.nz>.

parties expressed that there had been a trend of Genesis' hedge contracts being 'take-it-or-leave-it', with limited room for negotiation to ensure that terms are suitable.[272]

282. That being the case, our assessment is that these parties' lack of interest in MSOs and HFOs is not necessarily indicative of their demand for risk management products supported by Huntly. Financial intermediaries also told us that HFOs are an important input to their businesses, enabling them to repackage and synthesise risk management contracts more suited to smaller interested parties.[273]

Applicants' submissions on access to Shaped Hedges

283. The Applicants submit that the Proposed Arrangements give rise to a greater ability and incentive for them to provide Shaped Hedge products to interested parties on terms that are more beneficial to those third parties because:

283.1. by design, there is remaining capacity not allocated to the Applicants (including Genesis' pre-existing commitments).[274] Genesis has told us that, "With the viability of Unit 2 underpinned as a result of the Arrangements, Genesis is in a position to, and intends to, design new risk products that are suitable to a broader range of participants (in terms of volume, term, etc.) in order to best utilise that capacity. While there has been very limited demand for these products outside of the four large generators to date, the presence of Unit 2 means that Genesis is incentivised to continue attempting to design products that meet other participants' (e.g., independent generators and retailers, large industrials) stated needs."[275]

283.2. Counterparties would, all else equal, be longer on electricity in the factual, reducing their exposure to dry year risk and providing greater incentives to offer additional hedge products;[276] and

283.3. Counterparties are free to exercise their option at their discretion (provided their fuel contributions are met) without any constraint on how they act in the market having done so.[277] Counterparties could therefore compete against Genesis as sellers in the hedge market.[278]

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272 [ ] [ ]

273 [ ] [ ]

274 Interview with Genesis (21 August 2025) at [6]-[7]. Interview with Mercury (21 August 2025) at [39]. Interview with Contact (26 August 2025) at [6]. Application at [9.7].

275 Application at [9.5].

276 Annexure 1 at [13(C)]-[14]. [ ]
[ ] [ ]

277 Application at [1.10(c)] and [5.4(j)].

278 [
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284. Genesis has stated that it is already engaging with independent retailers, independent generators and industrial customers to understand their needs.[279]

285. We note that Genesis' June 2025 Board paper indicated that additional capacity contracts to the Proposed Arrangements could be sold commercially.[280]

Interested parties' submissions

286. Some submitter supported the Applicants' suggestion that more firming capacity would be offered to the market. For example, Energy Resources Aotearoa noted the existence of previous hedge offers as evidence of Genesis' willingness to offer more contracts in the future.[281] Other interested parties supported the suggestion that, because the large Gentailers would have underwritten the capital and operating expenditure of Unit 2, Genesis may be able to offer hedges for uncontracted volumes to a broader range of interested parties.[282]

287. However, a number of submitters expressed doubt that hedges offered by Genesis would be on suitable terms for smaller interested parties. In particular, submitters were concerned that:

    287.1. Genesis would be able to dictate the terms of these products.[283]

    287.2. Products might not be suitable, just as previous HFO products have not been.[284]

    287.3. Prices could be different compared to the prices agreed in the Proposed Application given differences in the contract terms.[285]

288. Other parties expressed scepticism that the Applicants would have incentives to offer hedge cover at all. Interested parties noted that there are no mandatory obligations in the Proposed Arrangements to offer hedges to third parties.[286] Some submitters were of the view that:

    288.1. a significant proportion of the firming volume would be locked up between the Applicants, leaving little to no volume for the broader market[287] (however, as

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279 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 8. Estelle Sarney "Genesis engaging with market on short-term flexibility products" (1 September 2025) <www.genesisenergy.co.nz>.

280 Genesis Board Paper "Huntly Strategy Energy Reserve: For Approval" (June 2025) at [2.1(b)].

281 Submission from Energy Resources Aotearoa (27 August 2025) at [10].

282 Interview with Transpower (18 August 2025) at 7. Submission from WEL Networks (21 August 2025) at 1.

283 [ ]

284 Interview with 2degrees (19 August 2025) at 3. Interview with Electric Kiwi (22 August 2025) at [5.1].

285 Interview with 2degrees (19 August 2025) at 3. Submission from Lodestone (27 August 2025) at 1. Submission from Haast Energy (13 August 2025) at 3.

286 Submission from Lodestone (27 August 2025) at 2. Submission from Mercuria (1 September 2025) [Public] at 2.

287 Submission from 2degrees (27 August 2025) at 2. Submission from Mercuria (1 September 2025) [Public] at 2.

stated in the Application, around 135 MW of Rankine Unit capacity remains uncontracted);

288.2. having underwritten Unit 2 through the Proposed Arrangements, Genesis is no longer incentivised to supply additional hedges to third parties;[288] and

288.3. the Gentailers will remain incentivised to limit access to hedging arrangements for third party retailers to cover their own exposure[289] or prioritise supply of Shaped Hedges to their retail arm,[290] instead of offering additional hedges to the market.

Our assessment of access to Shaped Hedges

289. We considered whether the Applicants would have the ability and incentive to offer hedges to interested parties under the Proposed Arrangements.

290. The Commission provisionally accepts that the preservation of Unit 2 in the factual provides the Applicants with greater ability and incentive to offer Shaped Hedges to interested parties compared to a counterfactual in which Unit 2 is retired. In particular, we note that:

290.1. Unit 2 provides the market with capacity that would not be available to the market in a counterfactual where Unit 2 is retired.

290.2. Security of supply benefits arising from the Proposed Arrangements reduce the Applicants' dry-year risk, so that in principle each may have a greater ability and appetite to reallocate resources that would otherwise have been held to mitigate this risk. This could include selling hedges to interested parties backed by more flexible and potentially cheaper resources than those provided by the Proposed Arrangements.

290.3. In addition to the 135 MW of unallocated Rankine capacity indicated in the Application, a further 85 MW will become available at the end of 2026 as Genesis' current HFO arrangements roll off.[291] This will result in [ ] of capacity that Genesis is able to use to back hedges with other parties.

291. We note the concerns of some interested parties that securing the capital and operating expenditure associated with the Rankine Units through the Proposed Arrangements will reduce Genesis' incentives to offer further hedges. However, we consider that Genesis likely has a commercial incentive to generate revenue certainty from the Rankine Units by contracting out residual uncontracted capacity. We note

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288 [ ] [ ] [ ]

289 [ ]

290 Submission from 2degrees (27 August 2025) at 2. [ ]

291 Genesis, "Huntly Firming Options" (May 2024) <www.media.genesisenergy.co.nz>. Genesis, NZX Market Release (12 August 2024) <media.genesisenergy.co.nz>. Interview with Genesis (21 August 2025) at [7.1].

that the Proposed Arrangements only cover Genesis' risk relating to 225 MW or almost one Rankine Unit of capacity. Genesis has two additional Rankine Units, with 135 MW of spare capacity, for which Genesis must pay the associated operating and capital expenditure. To elect not to sell this capacity in the form of hedge contracts would expose Genesis to greater spot price volatility risk, with reduced revenue certainty, potentially affecting the value of the Rankine Units in their portfolio.[292]

292. We consider that some third parties, such as financial intermediaries, are likely to benefit from the ability to access hedges for this capacity relative to the counterfactual.

293. The extent to which Genesis is incentivised to offer hedge products on terms that are suitable for smaller parties is less clear. We note that Genesis' prior HFO and MSOs have not been suitable for a wide range of parties.

294. However, we acknowledge the statements made by Genesis in its Application that:

    294.1. with the viability of Unit 2 underpinned, Genesis is in a position to, and intends to, design new risk products that are suitable to a broader range of participants; and

    294.2. Genesis is already working to understand the needs of interested parties.

295. The Commission takes note of Genesis' commitment in the Application to design products that are suitable for the needs of interested parties (such as financial intermediaries, independent retailers, generators, and industrial customers), and in making our Draft Determination we have placed weight on a public benefit arising in the form of access to hedge contracts for a broader range of participants.

296. The Commission expects Genesis to be able to promptly follow through on that commitment. We expect these products to be offered on fair and reasonable terms, and to take into account that Genesis has already secured the capital and tenure it deems necessary to commit to keeping three Rankine Units in market.

Potential detriments

297. As part of our assessment, we have assessed the potential detriments that potentially arise from the Proposed Arrangements against a counterfactual that Unit 2 will be retired.

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[292] For example, while some interested parties expressed that Genesis would be incentivised to withhold additional capacity to benefit from high prices during dry sequences, we accept Genesis' submission that dry sequences severe enough to lead to significant wholesale prices are relatively infrequent and unpredictable. The long lead time needed to prepare Unit 2 to generate from cold and the volatile nature of hydrology in New Zealand makes committing a Rankine Unit to meet an expected dry sequence and high price period risky. Sudden rainfall, as seen in August 2024 just after the Tiwai demand response and Methanex gas deal were called, could supress prices unexpectedly resulting in significant losses from committing unhedged capacity from Unit 2. Selling any residual capacity through hedges provides revenue certainty to Genesis and mitigates the impact of a sudden change in conditions if Unit 2 is called by a hedge counterparty.

298. The Applicants submit that there will be no public detriments stemming from a lessening of competition as a result of the Proposed Arrangements because:

    298.1. the competitive effect of the Proposed Arrangements is that more capacity is made available than would otherwise be the case and at lower wholesale electricity prices than would be anticipated;[293] and

    298.2. the Proposed Arrangements are unlikely to result in coordinated effects.[294]

299. The Applicants, however, do refer to detriments that may arise as a result of increased emissions stemming from continued operation of the coal-powered Unit 2.[295]

300. As part of our assessment, we have assessed the likelihood and magnitude of the following potential detriments based on consultation with the Applicants and interested parties:

    300.1. coordination facilitated by multilateral negotiations between the Applicants;

    300.2. disincentives to invest in additional generation and firming capacity;

    300.3. increased carbon emissions; and

    300.4. other concerns such as entrenching market power in the Applicants.

301. We consider each of these detriments in detail below.

Facilitate coordinated behaviour

Summary

302. The Applicants submit that coordination as a result of the Proposed Arrangements is unlikely, even though the Applicants are aware of the price the others would pay to access the Option Capacity, because this is no different to any other market arrangement.[296]

303. The Applicants also noted that there is no increase in coordination compared to the counterfactual because, in the counterfactual, the capacity that is the subject of the Proposed Arrangements would be removed from the market entirely.

304. As part of our consultation, we sought feedback about whether the Proposed Arrangements are likely to facilitate coordination between the Applicants. We received mixed evidence on whether the Proposed Arrangements would be likely to facilitate coordination in the wholesale electricity market relative to the counterfactual:

    304.1. Submitters noted that any scenario where four large players have an agreement, have visibility of each other's actions, and are potentially sharing

293 Application at [10.20].
294 Application at [9.10]-[9.13].
295 Annexure 1.
296 Application at [9.11].

information would be problematic as this reduces the competitive tension among the Applicants.

304.2. However, other interested parties noted that the electricity sector is generally transparent, and interested parties could reasonably infer each other's actions in the market. Submitters noted that the Proposed Arrangements are unlikely to change this industry dynamic.

305. We provisionally accept that the Proposed Arrangements introduce some additional transparency (in terms of pricing and timing when a call option is exercised) between Genesis and each of the Counterparties relative to a counterfactual in which Unit 2 is retired.

306. However, we consider the Proposed Arrangements are unlikely to change the dynamics in the market in any meaningful manner as players already closely monitor each other in the ordinary course of business and the Proposed Arrangements will not alter this. In addition, certain information about the Applicants' actions can be inferred by interested parties monitoring the EA's regular data publication within a relatively short period of time. The EA publishes all bids and offers for electricity on the spot market daily (for the prior day). So, for example, if Genesis started a Rankine Unit in response to a call, this would be reflected in the spot price because of the additional generation available.

Applicants' submissions on potential for coordinated behaviour

307. The Applicants submit that the Proposed Arrangements are unlikely to result in market-wide coordination because:

307.1. in the counterfactual where there is no Unit 2, there will be less Huntly generation capacity available and it will all be controlled by a single firm (Genesis), which would result in less competition than the factual;[297]

307.2. although the Applicants will know to some extent the price the others would pay to access the Option Capacity, this is no different to any other market arrangement. While Genesis' wholesale arm would know when a Counterparty exercised its option, the other Counterparties may not;[298]

307.3. Genesis engaged the services of PWC to independently examine the process used to establish the price to limit the information flow among the Applicants. Other Applicants did not have visibility of the costs of running the Rankine Units.[299] Genesis informed us that the [ ]. Genesis conducted some modelling to estimate how often the Counterparties will call on their option. The Counterparties have no visibility on when others are calling their option.[300]

297 Application at [9.9]-[9.10].
298 Application at [9.11].
299 Interview with Genesis (21 August 2025) at [18.1].
300 Application at [9.11] and [9.13].

308. The Applicants cite our decision in *Contact/Manawa*, where we observed that:[301]

    308.1. coordination is less likely when demand and supply are highly volatile, and these options are more likely to be called in a dry winter when volatility is high;

    308.2. asymmetry in suppliers' net positions limit the sustainability of coordination; and

    308.3. it is not possible to establish if a deviation from a coordinated agreement is driven by a desire to reduce losses from a short position or a decision to undermine coordination.

309. The Applicants state that there are a range of factors which a supplier considers when contemplating the offer of hedges. This undermines the scope for any coordination due to the large number of parameters that would need to be agreed across multiple trading periods each day.[302] For instance:

    309.1. [ ] would consider [ ] among other parameters to make the most economic decision about whether to exercise its call options under the Proposed Arrangements. It claims that many factors affect when an option is called, so it is unclear how other Counterparties will think about this. In addition, calling an option does not mean that Genesis will turn Unit 2 on and, when the call is exercised, Genesis will treat it like any other hedge in its hedge book.[303]

    309.2. [ ] and [ ] told us that it will be difficult to infer when other Counterparties have called their options. They can monitor hydrology/other generation (including when Huntly is turned on) but would not be aware if an Applicant called its option.[304] Even if Counterparties can make inferences, this is no different to knowing any other transaction due to publicly available information in the market.[305]

Interested parties' submissions on potential for coordinated behaviour

310. We received mixed evidence on whether the Proposed Arrangements would likely facilitate coordination in the wholesale electricity market. Parties that did not express coordination concerns (or were neutral) informed us of the following:

    310.1. The Applicants are still incentivised to use the lowest cost fuel available to them and Huntly costs more than renewables.[306] Accordingly, Huntly will be used infrequently and, if a Counterparty is able to infer when others will call their option, it is unclear how that would be detrimental to competition.

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301 Application at [9.12]. *Contact/Manawa* at [173]-[207].

302 Application at [9.13].

303 [ ]

304 [ ] [ ]

305 [ ] [ ]

306 Interview with Transpower (18 August 2025) at 6.

310.2. While it is likely for Gentailers to infer that Counterparties called their option(s) by observing reductions in the coal stockpile, this is general market information which other Counterparties could infer too. Industry players closely watch each other in the ordinary course of business and there is public information published (eg, EA thermal dashboard/Genesis quarterly reports on coal).[307]

310.3. [ ] was doubtful whether the Proposed Arrangements increase the possibility of coordination and, if it does, it should not really "trigger alarm bells". The main concern is the potential for the unilateral exercise of market power during periods of system stress rather than coordinated effects now. [308]

310.4. [ ] acknowledged that it may be possible for the Applicants to coordinate, but this is required to deliver electricity when there is lack of supply. Such coordination may still be within the realms of public interest.[309]

311. Parties that expressed concerns about the Proposed Arrangements' likelihood of facilitating coordination told us the following:

311.1. [ ] noted that any scenario where four large players have agreement and visibility of each other's actions would be problematic and would reduce the competitive tension among the Applicants.[310] [ ] argued that a coal input as part of the pricing mechanism does not vary significantly, which enhances visibility among the Applicants to the exclusion of other interested parties.[311]

311.2. Haast Energy and Pulse expressed concerns that information sharing by the Applicants in relation to pivotal firming generation may weaken competition, especially in dry years. Common knowledge of option pricing and fuel cost arrangements reduces competitive uncertainty and risks facilitating coordinated behaviour. They consider that an insider information advantage is problematic where Unit 2 can materially influence price formation during dry or peak periods.[312]

311.3. [ ], [ ], [ ] and [ ] state that the Applicants could infer if another Applicant has exercised its option based on its understanding of each other's generation make-up, knowledge of when each Applicant is experiencing pressure on its portfolio, observing a Rankine Unit start up unexpectedly, and industry knowledge of the levels of the coal stockpile. [313] Submitters stated that

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307 Interview with MEUG (25 August 2025) at 9. EA "Thermal fuel information" <ea.govt.nz>.

308 [ ]

309 [ ]

310 [ ]

311 [ ]

312 Submission from Haast Energy (13 August 2025) at 2-3. Submission from Pulse Energy (26 August 2025) at 1-2.

313 [ ] [ ] [ ] [ ]

this may increase the likelihood for coordination.

Our assessment of potential for coordinated behaviour

312. We are provisionally of the view that the Proposed Arrangements will not facilitate or enhance the likelihood of coordinated behaviour because:

    312.1. asymmetry in the Applicants' generation assets (varying proportions of wind, solar, hydro, and geothermal assets) makes coordination and its sustainability unlikely;

    312.2. the market is generally transparent due to public information disclosure (half hourly auction/trading results, monthly Energy Security Outlook (**ESO**) by Transpower, the EA's thermal fuel dashboard (coal, diesel, gas), daily hydro storage updates, and daily disclosure of the previous trading days' market offers and scheduling inputs);

    312.3. the information exchanged between Genesis and each of the Counterparties is limited and unlikely to materially increase transparency that would increase the risk of coordination in the market;

    312.4. the Proposed Arrangements are unlikely to add anything of significant commercial value as any action taken by an Applicant will be public in a relatively short period of time (can be within 24 hours); and

    312.5. industry players closely monitor each other in the ordinary course of business and the Proposed Arrangements will not alter this.

313. Based on the reasons above, we provisionally consider that the Proposed Arrangements are unlikely to facilitate or enhance coordination relative to the counterfactual. We have therefore not placed weight on this detriment as part of our overall assessment.

Disincentivise investment in new generation and firming capacity

Summary

314. The Applicants submit that they will continue to invest in renewable projects or other forms of firming and the Proposed Arrangements are unlikely to disincentivise their investment commitments. Some of the investment commitments have been publicly announced and others are already being built.

315. We have received mixed evidence from interested parties:

    315.1. Some submitters told us that the Proposed Arrangements would crowd out or incentivise the delay of investment in new firming capacity. The improved security of supply from the Proposed Arrangements may lower wholesale prices which may disincentivise investment in new generation due to likely low returns.

315.2. Some submitters told us that declining gas availability incentivises the sector to invest in more generation assets to meet future demand. They see the Proposed Arrangements as complimenting investment in new generation opportunities as opposed to crowding it out.

316. We provisionally consider that the Proposed Arrangements would at most produce only a small public detriment, to the extent that some investment in firming is delayed at the margin. This is because:

316.1. the relevant long-run average price for long term investment still provides an incentive for generators to invest despite lower prices in the short-run; and

316.2. declining gas, growing reliance on intermittent renewables, and the aging nature of the Rankine Units will likely incentivise market participants to invest in firming capacity.

Applicants' submissions on incentives to invest in new generation and firming capacity

317. The Applicants submit that they will continue to invest in other renewable plants or other forms of firming even with the Proposed Arrangements.[314] They claim that each of the Applicants have independent, long-term strategies to grow their respective portfolios.

318. Mercury has publicly stated its intention to continue with its existing pipeline projects when presenting its FY25 full year results to investors.[315]

319. Meridian claims that it has a strong appetite for investment in new renewable generation and battery storage.[316] Additionally, Meridian sees no way that it could further accelerate its pipeline in the counterfactual to alleviate dry year risk in the near-term given the length of the consenting and build processes.[317]

320. Meridian is
[

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321. Genesis and Contact submit that they are equally incentivised to progress their existing investment commitments.[319]

322. Genesis strongly disagrees with any suggestion that continued operation of Unit 2 would crowd out investment. This is because:[320]

314 Application at [10.24].
315 Mercury "Full Year Results FY25" (19 August 2025) <www.mercury.co.nz> at 18. Interview with Mercury (21 August 2025) at [28.2].
316 Interview with Meridian (19 August 2025) at [14.1]. Application at [10.24(d)] and [10.29].
317 Annexure 6 at 4.
318 Interview with Meridian (19 August 2025) at [15.3].
319 Application at [10.24(a)]-[10.24(b)].
320 Application at [10.25]-[10.29].

322.1. The events of winter 2024 serve as an example that immediate solutions are necessary to respond to current market challenges, yet the reality is that it will be some time before new capacity will be available to the market. The primary role of keeping Unit 2 in the market is to meet the current shortfalls in renewable generation.

322.2. Even with the trend of renewables replacing thermal generation (such as Unit 2), there will still be a need for thermal capacity given that growing reliance on renewables exposes the sector to climatic conditions.

322.3. Given that a third Rankine Unit will be more expensive than any likely renewable investment, all interested parties are incentivised to invest in these cheaper alternatives.

323. The Applicants have further expressed that:

323.1. Thermal generation is complementary to investment in new renewable generation as it is utilised at different times.[321] A third Rankine Unit would be called upon when there is a shortfall of generation elsewhere in the system (eg, due to adverse weather conditions especially during dry years). Conversely, intermittent renewables are intended to be utilised in all years and year-round.[322]

323.2. Security of supply benefits from the Proposed Arrangements, including access to additional firming, will support intermittent renewable investment.[323] This extends to demand growth and investment by large industrials who require long-term certainty of wholesale prices.[324]

323.3. While lower wholesale electricity prices may affect investment decisions at the margin, this will not be material.[325] Investments in the pipeline would have priced in a third Rankine Unit already, and investment decisions are made based on long-run prices given that wind and solar are 30-year investments.[326]

Interested parties' submissions on incentives to invest in new generation and firming capacity

324. Interested parties have submitted that the Proposed Arrangements could affect incentives to invest in several ways.

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321 Application at [10.29]. Interview with Genesis (21 August 2025) at [33]. Interview with Mercury (21 August 2025) at [22]. Interview with Contact (26 August 2025) at [32].

322 Interview with Mercury (21 August 2025) at [25.1].

323 Interview with Meridian (19 August 2025) at [14.1]. Interview with Mercury (21 August 2025) at [29.1]. Interview with Contact (26 August 2025) at [32.1].

324 Interview with Contact (26 August 2025) at [32.1]-[32.2]. Interview with Mercury (21 August 2025) at [33.1]. Interview with Meridian (19 August 2025) at [32.2].

325 Interview with Mercury (21 August 2025) at [29.1]. Interview with Meridian (19 August 2025) at [14.1].

326 Interview with Meridian (19 August 2025) at 15.2.

325. Lower average wholesale electricity prices as a consequence of the Proposed Arrangements may disincentivise investment at the margin.[327] Some interested parties expressed that this would only have a minimal impact because prices would remain sufficiently high to incentivise investment in cheaper intermittent renewables and that investment decisions are based on long-run prices.[328]

326. We heard diverging views on whether security of supply benefits would support investment:

    326.1. Some interested parties expressed concerns that the Proposed Arrangements would crowd out or incentivise the delay of investment in new firming capacity.[329] Regarding renewables, we heard that the slow ramp up ability of Unit 2 is not ideal for firming intermittent renewables[330] and that, to the extent the Proposed Arrangements reduce price volatility, this would reduce incentives to invest in BESS which relies on price arbitrage opportunities.[331]

    326.2. Others considered incentives to invest would improve due to improved security of supply.[332] For example, interested parties considered that the riskiness of investments is likely to be reduced by providing long-term certainty (through the 10-year term) regarding the retention of firming capacity in the market and via any reduction in the volatility of spot prices.[333]

327. Interested parties also expressed that the current market context will influence incentives to invest in the factual:

    327.1. The sector is simultaneously facing growth in expected demand while declining gas availability has reduced generation capacity. The sector requires investment to recover lost gas capacity, let alone meet future demand. Interested parties claim the Proposed Arrangements complement other investment opportunities because the capacity of Unit 2 is insufficient to resolve these issues and meet the firming needs of the market.[334] They claim the Proposed Arrangements provide time to develop new capacity or alternative firming solutions.[335]

    327.2. As mentioned above (see paragraphs 246 to 247), Transpower's latest SOSA and Energy Security Outlook show that retaining a third Rankine Unit reduces

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327 Interview with the EA (20 August 2025) at 4. Submission from Electric Kiwi (27 August 2025) at [24]. Interview with MEUG (25 August 2025) at 8.

328 Interview with the EA (20 August 2025) at 4. [ ]

329 Submission from IEGA (27 August 2025) at 3. [ ]

330 [ ]

331 Interview with MEUG (25 August 2025) at 8.

332 [ ]

333 Interview with Transpower (18 August 2025) at 6. Submission from Energy Resources Aotearoa (27 August 2025) at [3(c)].

334 [ ] Interview with Transpower (18 August 2025) at 3 and 6. Submission from Energy Resources Aotearoa Submission (27 August 2025) at [11]. Submission from WEL Networks (21 August 2025) at 1.

335 [ ] Interview with Transpower (18 August 2025) at 3. Submission from WEL Networks (21 August 2025) at 1. Submission from Lodestone (27 August 2025) at 1.

the risk that New Zealand will not have enough electricity, especially during dry periods when hydro lakes are low. [336] Current consented projects are insufficient, so additional as-yet unconsented generation will be needed over the next decade.

327.3. In this context, and given the intention for the energy sector to decarbonise, interested parties expressed that there are plenty of opportunities and existing momentum in renewables investment.[337] This is because:

327.3.1. Renewables generally have lower marginal costs than Unit 2, so there will be opportunities for new investment to undercut the Proposed Arrangements.[338]

327.3.2. Intermittent renewables are a complement rather than a substitute for thermal generation; Unit 2 is generally offered at times when there is a shortage of intermittent renewable fuel supply.[339]

327.3.3. There is limited investment in alternatives to the Proposed Arrangements given uncertainty surrounding thermal generation and decarbonisation.[340]

327.3.4. [ ] claims that Unit 2 is an old plant (40 – 50 years old), meaning the sector will require new investment in more efficient options and to maintain firming capacity after Unit 2's eventual retirement.[341]

327.3.5. MEUG considers that the Gentailers are incentivised to delay investment to keep the spot price high.[342]

Our assessment of incentives to invest in new generation and firming capacity

328. We consider the Proposed Arrangements could, in principle, affect incentives to invest in two ways:

328.1. First, lower wholesale electricity prices if Unit 2 remains in the market could reduce investment incentives at the margin.

328.2. Second, preserving the firming capacity of Unit 2 through the Proposed Arrangements may incentivise generators to delay investment in new, more efficient firming capacity.

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336 Submission from Transpower (26 August 2025) at [4]-[10], Table 1 and Figure 1.

337 Interview with Transpower (18 August 2025) at 1. Submission from Energy Resources Aotearoa (27 August 2025) at [11].

338 Interview with the EA (20 August 2025) at 6. Submission from Energy Resources Aotearoa (27 August 2025) at [11].

339 Submission from Energy Resources Aotearoa (27 August 2025) at [11].

340 [ ] Interview with MEUG (25 August 2025) at 6. Interview with Transpower (18 August 2025) at 2.

341 [ ]

342 Interview with MEUG (25 August 2025) at 8.

329. However, we consider that, in practice, any impact on incentives to invest is likely to be marginal.

Effect of lower wholesale prices in the factual

330. Investment decisions in the energy sector are grounded in a range of factors including generators' projections of their ability to earn a return on the investment in the future. One of the factors that influences the level of return on investment that a generator may expect to achieve is the projected spot price for wholesale electricity. Higher spot prices generally provide generators with increased profitability which in turn improves investment levels.

331. At a plant level, if future long run average spot prices exceed the long run average cost of generation, then investment is likely to be profitable. All else being equal, a decrease in the average spot price would affect investment decisions at the margin by reducing the expected return on investment.

332. Given that we estimate the Proposed Arrangements are likely to reduce average spot prices by between 12% and 13% in the near term compared to a counterfactual of Unit 2 being retired,[343] we would also expect the Proposed Arrangements to decrease incentives to invest. However, we consider that any decreased incentive to invest is likely to be marginal because:

    332.1. Generators consider long-run prices when making investment decisions. While NERA considers that prices may still be 6% lower in the factual by 2037 (suggesting that the Proposed Arrangements would have a longer-term effect on prices),[344] we understand that generators consider a much longer 30 to 40-year time horizon when considering investment in intermittent renewables. While shorter term elevated prices may still influence average prices over a longer time horizon, we consider that the relevant long-run average price still provide an incentive for generators to invest.

    332.2. There is already an investment pipeline under construction which is unlikely to be abandoned because of the Proposed Arrangements.[345]

    332.3. The investment pipeline is predominantly comprised of intermittent renewable generation projects that would have considerably lower short-run marginal costs relative to thermal plants. Therefore, any reduced average price would likely remain above the price that makes these investments economically rational. Additionally, this provides opportunities for new investment to effectively 'undercut' the Rankine Units.

    332.4. Intermittent renewables tend to be offered to market at different times to the Rankine Units. Renewables are generally offered year-round while Unit 2 will

343 As discussed in Attachment A.

344 Annexure 1 at [26].

345 For example, as of 18 September 2025, the EA's Generation Investment Pipeline dashboard notes that there is 831 MW of new capacity already committed and 3.58 gigawatt of new capacity expected to be commissioned in 2026. EA "Generation investment pipeline" (16 September 2025) <www.ea.govt.nz>.

predominantly be offered as backup supply during times of scarce intermittent renewable supply. In other words, Unit 2 will only affect a limited number of trading periods,[346] and will often be supplied in times where hydro, solar, and wind plants are constrained. Any reduction in price when an investment is unlikely to be dispatched would not materially affect the decision to invest in that plant.

333. Balancing these factors, while lower wholesale electricity prices are likely to reduce investment incentives at the margin, this is likely to be offset to some extent by the factors described above. As a result of these conflicting factors, the effect of lower average wholesale electricity prices on investment incentives is likely to produce, at most, only a small public detriment.

334. We are therefore provisionally of the view that lower wholesale electricity prices in the factual relative to the counterfactual as a result of the Proposed Arrangements will not disincentivise investment to any material extent. To the extent that wholesale market participants are already anticipating that Unit 2 will remain, wholesale electricity prices may remain slightly elevated over the short-to-medium term (but lower compared to a scenario where Unit 2 exits the market), further creating incentives for counterparties to invest in new generation. The worst-case scenario would be neutral or a marginal detriment, which we do not view as likely.

Potential to delay investment

335. We have additionally heard that the Proposed Arrangements may have the effect of delaying investment in new, more efficient firming options. By preserving Unit 2 for an additional 10 years, there may be a reduced urgency for such investment by interested parties.

336. For the reasons stated above, we consider it likely that interested parties will remain incentivised to progress their investment pipelines in conjunction with the Proposed Arrangements. This is because:

    336.1. New generation is needed due to declining availability of gas. This is confirmed by Transpower's SOSA reports which suggests more firming investment is required in both the factual and counterfactual to meet energy demands.[347]

    336.2. The time to plan, consent, build, and commission a new plant further limits the extent to which investment can be delayed. Given the aging nature of the Rankine Units, new firming capacity will be necessary in the future. We consider interested parties will remain incentivised to make such investment to manage their dry year risk. We note that new options for renewable firming capacity (outside of thermal generation) are coming to market (such as BESS).

[346] We estimate that Unit 2 was dispatched in approximately 30% of trading periods in the 2-years to April 2025, and on average in 25% of trading periods in a year between 2014 to 2024.

[347] Transpower submission (26 August 2025) at 3, Figure 1.

337. We further consider that the Counterparties are incentivised to minimise the frequency with which they call their options, which they can achieve by investing in sufficient generation to remain long on generation, or investing in cheaper alternative firming options. Renewable firming technologies are cheaper than high marginal cost coal plants. Therefore, the counterparties are likely to continue to seek to develop renewable firming options to eliminate the need to rely on more costly firming capacity from Unit 2.

338. To the extent that the Proposed Arrangements may delay the introduction of additional and/or more efficient firming capacity, we would consider this to be a public detriment. However, in light of declining gas, growing reliance on intermittent renewables, and the aging nature of the Rankine Units, we consider there remains an incentive for interested parties to invest in firming capacity and that, even if the Proposed Arrangements were to enable the delay of investment, the time to build new generation limits the extent to which this can be delayed.

339. Consequently, we provisionally consider that the Proposed Arrangements would at most produce only a small public detriment to the extent that some investment in firming is delayed at the margin.

Increase carbon emissions

Summary

340. Genesis argues that any increased carbon emissions from operating Unit 2 will be mitigated via the Emissions Trading Scheme (**ETS**).

341. On balance, we consider that this detriment is likely to be relatively small and can be internalised to a large extent by purchasing/using carbon credits under the ETS.

Applicants' submissions on carbon emissions

342. The Applicants note that it is likely that more carbon would be emitted by the Applicants under the factual scenario against any counterfactuals where Unit 2 is, and is not, retired.[348] However, the Applicants submit that:

    342.1. The extent of any increase in emissions would depend on the extent to which Unit 2 is needed under the factual, the carbon intensity of alternative plants under the counterfactual, and any deferred electrification downstream in the counterfactual as a result of high electricity prices.[349]

    342.2. Negative externalities arising as a consequence of any increase in carbon will be internalised given that the parties would effectively pay for carbon emissions under the ETS by surrendering more carbon units.[350]

348 Annexure 1 at [33]-[34].
349 Annexure 1 at [33].
350 Annexure 1 at [35]-[38].

Interested parties' submissions on carbon emissions

343. We received submissions which indicate the need for thermal generation despite their carbon emissions. For example:

343.1. Transpower submits that renewables play a huge role in energy generation and a small uptick in coal usage does not outweigh security of supply benefits.[351]

343.2. Electricity sector emissions are already low by international standards and retaining Unit 2 in the market supports the electrification drive.[352] Applicants and other interested parties retain strong incentives to invest in new renewable generation given the high cost of thermal generation (ie, it is cheaper to produce other forms of electricity).[353]

Our assessment of carbon emissions

344. We acknowledge that Unit 2, when it is operational, will emit more carbon than would be the case if it was decommissioned, although we note that it is used relatively infrequently.

345. On balance, we consider that this detriment will be internalised to some/a large extent by purchasing/using carbon credits. We also understand that Genesis intends to transition to biomass (with lower emissions) over time and replace the use of coal.[354]

346. To the extent that there is a remaining public detriment, we consider that in the short- to medium-term there are few alternatives to thermal firming capacity. Absent the Proposed Arrangements, it is likely that Unit 2 would be replaced by the increased use of other carbon emitting plants, such as the Whirinaki diesel generator operated by Contact, resulting in little to no change in the volume of carbon emissions and likely using more expensive fuels.

347. Consequently, we consider that the Proposed Arrangements would at most produce only a small public detriment due to carbon emissions at the margin, but this is likely to be largely mitigated by carbon credits.

Other concerns raised

Entrench market power

348. As part of our consultation, some submitters expressed concerns that that an unintended consequence of the Proposed Arrangements is to entrench the market power of the Gentailers in the supply of peak/super-peak hedge products.[355] The concern expressed was that concentration of long-term firming capability among the

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351 Interview with Transpower (18 August 2025) at 5-6.

352 Energy Resources Aotearoa submission (27 August 2025) at [12].

353 Energy Resources Aotearoa submission (27 August 2025) at [11].

354 Malcolm Johns "Genesis committed to biomass at Huntly Power Station" (13 December 2024) <www.genesisenergy.co.nz>.

355 Lodestone Energy submission (27 August 2025) at 2. Pulse submission (26 August 2025) at 2. Submission from 2degrees (27 August 2025) at 2. Submission from Electric Kiwi (27 August 2025) at [8], [32] and [36]-[39]. Submission from Haast Energy (13 August 2025) at 1-3.

Gentailers for a decade risks further entrenching their control over flexible generation and limiting access for independent retailers, independent generators, and other new entrants.[356]

349. Haast Energy noted that the EA's Level Playing Field work recognises the competition risks arising from the Gentailers' control of flexible generation, and the importance of hedge availability to support retail competition.[357]

350. The Applicants told us that any incentive Genesis might otherwise have to exercise market power in the spot market with the Rankine Units is constrained because each of the Counterparties could enter into secondary trades, effectively competing against Genesis as sellers. The presence of the Counterparties in the Proposed Arrangements weakens Genesis' market power.[358]

351. Our provisional view is that the Proposed Arrangements are unlikely to entrench market power because:

    351.1. Genesis would need to pay the Counterparties for any excess of the spot price over the fixed price at the Huntly node if the option were called;

    351.2. the Proposed Arrangements allow for capacity to be shared among the Counterparties and the Counterparties are free to enter into secondary trades, further competing with Genesis (and each other) and limiting Genesis' market power. This is particularly the case when compared to a counterfactual in which Unit 2 is closed and the capacity associated with the remaining two Rankine Units is controlled by Genesis alone; and

    351.3. there is 135 MW of remaining Rankine Unit capacity, meaning that access for independent retailers, independent generators, and other new entrants remains available.

352. Accordingly, we do not think that it is likely that the Proposed Arrangements will give rise to detriments in the form of entrenchment of market power.

Exclusion of other interested parties in the Proposed Arrangements

353. Some interested parties submitted that the exclusion of parties other than Gentailers from the Proposed Arrangements lessen competition compared to a counterfactual in which Genesis, for example, conducted an open tender process for Huntly capacity.

354. However, as discussed earlier (see paragraphs 164 to 166), we have concluded that this is not a likely counterfactual, and so this is not a relevant detriment we can place weight on.

355. However, we note that in the Framework Agreement, provision is made for additional parties to become a party to the Proposed Arrangements.

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356 Submission from Haast Energy (13 August 2025) at 3.

357 Submission from Haast Energy (13 August 2025) at 3.

358 Application at [9.3].

[

]359 We have recorded elsewhere in this Draft Determination our expectations on Genesis that interested parties wishing to access Huntly capacity will not be excluded from accessing hedge contracts, whether as additional counterparties to the Proposed Arrangements if that is their preference or by purchasing hedge cover that better suits their needs, as Genesis has indicated it is committed and incentivised to do.

Balancing of benefits and detriments

356. On the basis of the available evidence so far, our view is that authorising the Proposed Arrangements is more likely than not to lead to a net public benefit. That is, the Proposed Arrangements will be likely to result in benefits to the public that would outweigh the detriments.

357. Given the difficulty in producing quantitative estimates for several of the likely impacts, and given that we do not consider quantitative estimates are necessary to enable us to reach a view on the likely net public benefit, we have made this assessment qualitatively in accordance with the Court of Appeal's decision in *Godfrey Hirst*.

358. We consider that the Proposed Arrangements are likely to produce significant security of supply public benefits through the preservation of firming capacity at Huntly relative to a counterfactual in which Unit 2 is retired. We have placed material weight on this public benefit, consistent with evidence from a range of interested parties regarding the likelihood and magnitude of this benefit.

359. As a flow-on from the security of supply benefit, we expect lower average wholesale electricity prices compared to the counterfactual in which Unit 2 is retired. While there is uncertainty regarding the exact magnitude of this public benefit, the evidence before us indicates that lower wholesale prices will produce a sizeable public benefit in the form of new consumer surplus, potentially in the range of $13.5m – $15.8m over a five year period.

360. The Commission provisionally accepts that the Proposed Arrangements provide Genesis with a greater ability and incentive to offer a greater number of hedges to interested parties compared to a counterfactual in which Unit 2 exits the market. The Commission takes note of Genesis' commitment in the Application to design products that are suitable for the needs of interested parties (such as independent retailers, generators, and industrial customers), and places weight on a public benefit in the form of access to hedge contracts for a broader range of participants arising.

359 Genesis' response to RFI dated 1 September 2025 (6 September 2025) at 1.

361. Despite assessing these public benefits qualitatively, we are satisfied that the magnitude of these benefits are likely to outweigh the detriments in aggregate.

362. We do not place material weight on the public detriments that we have assessed. The evidence before us suggests that each would only be of limited magnitude and likelihood. In summary:

    362.1. We are provisionally satisfied that the Proposed Arrangements will not increase the risk of coordination in the wholesale market. Asymmetry in the Applicants' generation assets weakens coordination sustainability, and general market transparency means that the limited amount of information exchanged through the Proposed Arrangements is unlikely to add anything of significant commercial value to the Applicants.

    362.2. While lower wholesale prices may disincentivise investment incentives at the margin, generators consider long-run average prices rather than short/medium term variations, Unit 2 will often be dispatched when intermittent renewables (that comprise much of the pipeline) are constrained, and any reduction in price volatility due to greater security of supply would counteract this effect.

    362.3. We are currently not satisfied that a material public detriment would arise from any delay in investment. The market requires additional firming capacity on top of that retained through the Proposed Arrangements, and the time it takes to invest minimises parties' abilities and incentives to delay any new investment.

    362.4. We have seen no evidence to suggest that the ETS will be ineffective at internalising public detriments arising from increased carbon emissions.

    362.5. We consider it unlikely that the Proposed Arrangements will entrench market power because Genesis would need to pay the Counterparties for any excess of the spot price over the fixed price at the Huntly node. Further, sharing capacity with Counterparties limits Genesis' market power in the factual.

    362.6. We are not satisfied there is a likely detriment arising from interested parties being excluded from the Proposed Arrangements.

363. The exact magnitude of any public benefits and detriments are likely a function of the frequency of dry years over the period for which authorisation is sought. However, we consider that the scenarios that result in the largest public detriments are the same as those which produce the largest public benefits.

    363.1. Under favourable weather conditions (wet winters), Unit 2 is unlikely to be regularly required, resulting in the Proposed Arrangements having a broadly neutral impact (ie, limited differences in benefits and detriments between the factual and the counterfactual). The exception to this is the security of supply impact. Even under favourable weather conditions, market participants face risks associated with plant outages and the threat of weather conditions changing. Preserving Unit 2 provides certainty of supply in the event of such supply constraints, minimising the risk market participants face and leading to a

lower forward electricity price curve. That is, interested parties expect electricity prices to be relatively lower in the future compared to a counterfactual where Unit 2 exits the market.

363.2. Under dry year conditions, Unit 2 would be dispatched, producing the largest magnitude of security of supply benefits, including the largest reduction in average wholesale prices. However, this may allow Counterparties to engage more frequently while exercising their call options, produce the most carbon emissions, disincentivise more investment at the margin due to a larger price reduction, and result in the largest entrenchment of market power if other interested parties are not offered hedges by Genesis. For the reasons outlined above, we place limited weight on the likelihood and magnitude of each of these public detriments. The security of supply and lower wholesale price benefits significantly outweigh these public detriments.

364. Consequently, we are provisionally satisfied that, in all scenarios, the Proposed Arrangements will likely produce a net public benefit.

Length of the Proposed Arrangements

Summary

365. The Commission can grant authorisation for such period as it considers fit.[360]

366. Having regard to the need for Genesis to recover the upfront investment over a commercially palatable time and given our overall assessment of the likely benefits and detriments, on balance we consider it appropriate to authorise the Proposed Arrangements for 10 years.

Applicants' submissions on duration

367. The Applicants submit that authorisation for the Proposed Arrangements should be granted for a period of 10 years to provide the requisite certainty in terms of the investment in the third Rankine Unit.[361]

368. In particular, Genesis notes that
[

].[362] This is also reflected in the exit fee after 5 years, which is required to recover the front-loaded capital costs and other expenditure.

Interested parties' submissions on duration

369. We received mixed feedback about the 10-year duration.

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360 Section 61(2) of the Act.

361 Application at [4.9].

362 Genesis' response to RFI dated 20 August 2025 (9 September 2025) at 9-10.

370. Several parties supported the 10-year duration, for example on the basis that:

370.1. The 10-year period was proportionate to the certainty and investment required to give effect to the Proposed Arrangements, including operational costs, maintenance, and employing/training staff to support the initiative.[363]

370.2. In the electricity sector, 10 years is not a significantly long lead time for developments[364] and, in fact, the Rankine Units might be required for even longer, particularly given the intermittent nature of renewables and deep dry year risk,[365] as well as the limitations/reduction in the gas market.[366]

370.3. The 10-year period requested could be seen as time needed to afford the industry time to plan for the following decade.[367]

370.4. The 10-year term is also not out of step with some long-term hedges in the electricity market[368] and would provide greater certainty for the risk profile in the market, which should lead to lower prices.[369]

371. Other parties expressed the view that a minimum of 5 years would provide sufficient certainty for Genesis to keep the Rankine Unit operational.[370]

372. Some parties expressed the view that the timeframe was too long because of concerns that the Proposed Arrangements would:

372.1. remove the competitive constraint between the Gentailers;[371]

372.2. result in a perceived lack of incentives to invest in renewables;[372] and

372.3. lock up a significant volume of flexible generation,[373] possibly leading to incentives to control the flexibility in the system and entrench market power.[374]

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363 Interview with Transpower (18 August 2025) at 8. Interview with MEUG (5 August 2025) at [12.2].

364 [ ]

365 Interview with Transpower (18 August 2025) at 3. In addition, it is unknown how much of the current generation pipeline will receive consent across the next 10 years, which is why it is envisaged that Unit 2 would play a crucial role during this period. Transpower sees the need for thermal power stations as a back-up until 2050. Transpower "Whakamama I Te Mauri Hiko: Empowering our Energy Future" (March 2020) <static.transpower.co.nz>.

366 Submission from Transpower (26 August 2025) at [8], [10], [18] and [23].

367 [ ].

368 Interview with the EA (20 August 2025) at 5. EA "Electricity hedge prices and conditions for this winter" (11 June 2025) <ea.govt.nz>.

369 [ ] [ ]

370 [ ][ ] [ ]]

371 [ ]

372 Interview with Consumer NZ (26 August 2025) at [16.1].

373 Submission from 2degrees (27 August 2025) at 4. Interview with Consumer NZ (26 August 2025) at [16.1].

374 Submission from emhTrade (1 September 2025) [Public] at 6.

373. Participants also suggested the timeframe was unnecessary because another alternative was likely to be found within this timeframe.[375]

Our assessment

374. We accept Genesis's submission that the 10-year period is required to recover the necessary investments to maintain and keep Unit 2 operational and deliver the other benefits of the Proposed Arrangements.

375. We have not found credible evidence that another effective alternative energy source could be deployed within this timeframe, or that Gentailers would be disincentivised to continue investing in renewables.

376. Having regard to the need for Genesis to recover the upfront investment over a commercially feasible time and given our overall assessment of the likely benefits and detriments, on balance we consider it appropriate to authorise the Proposed Arrangements for 10 years.

Draft Determination

377. The Commission's Draft Determination is to grant authorisation as it is provisionally satisfied that the Proposed Arrangements will, in all the circumstances result, or be likely to result, in a benefit to the public which will outweigh any lessening in competition that might arise.

378. Accordingly, the Commission's Draft Determination is to authorise the Proposed Arrangements until 31 December 2035.

Interim Authorisation

379. The Applicants have not sought an interim authorisation for the Proposed Arrangements. That said, the Commission has the power to grant interim authorisation of its own motion.[376]

380. At this stage, the Commission has not considered whether to grant interim authorisation for the Proposed Arrangements because, subject to the feedback received in response to the Draft Determination, it may be possible to issue a final determination by November 2025.

381. However, the timeframes for making a final determination, and the decision whether to grant any interim authorisation, are subject to consultation and feedback received on this Draft Determination.

Dated this 29th day of September 2025

375 [ ]

376 Section 65AAA(1) of the Act. See also Authorisation Guidelines at [171].

John Small
Chair

Attachment A: Further details on methodology to assess the price effect of the Proposed Arrangements

382. This Attachment outlines further details on our methodology to estimate the price effects of the Proposed Arrangements to test NERA's quantification of any consumer surplus public benefits that arise from the Proposed Arrangements.

Overview of NERA's model

383. NERA, on behalf of the Applicants, submits that against a counterfactual where Unit 2 is retired, the Proposed Arrangements would result in lower average electricity prices because the supply curve would have additional capacity in it.[377]

384. Referring to analysis by Concept Consulting, NERA estimates that if one Rankine Unit is removed, prices would increase by around 10% – 12% between 2026 to 2028, and increase by 6% in the long term.[378]

385. As a consequence of lower average electricity prices, NERA submits that this will result in both additional consumer surplus relative to the counterfactual and a transfer of surplus from producers to consumers.[379]

386. To model these potential public benefits, NERA estimates each as the net present value (NPV) over a 5-year period, using:[380]

    386.1. Concept's modelled price scenarios to estimate factual and counterfactual prices; [381, 382]

    386.2. Average demand for electricity between June 2020 to May 2025 to estimate the factual quantity;[383]

    386.3. Literature on retail price elasticity of demand and data showing that wholesale electricity prices make up approximately 47% of retail electricity prices, to estimate counterfactual volumes.[384]

387. Using this approach, NERA submits that the Proposed Arrangements will result in public benefits in the form of:[385]

    387.1. a (partial) consumer surplus benefit of $13.5m – $15.8m.

    387.2. a transfer of surplus to consumers of $2.13b – $2.24b.

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377 Annexure 1 at [17].
378 Application at [10.15]-[10.16].
379 Annexure 1 at [18].
380 For further details on NERA's analytical framework, see Annexure 1.
381 Annexure 1 at [23]-[27] and Table 1.
382 NERA use two scenarios for prices in 2029 and 2030, given that NERA do not model these two years.
383 Annexure 1 at [24].
384 Annexure 1 at [28]-[29].
385 Annexure 1 at [30] and Table 2.

Appropriateness of NERA's price change scenarios

388. Key to testing NERA's model is assessing the suitability of the price change assumptions used.

389. Consequently, we have employed an alternative analytical approach to estimate the effect on price of removing Unit 2 from the market to verify the appropriateness of NERA's estimated range of public benefits. Our approach combines publicly available data from the EA on:

    389.1. Rankine Unit-level generation to identify actual generation from Unit 2 in each trading period;[386]

    389.2. plant level generation to identify total national dispatched electricity in each trading period;[387] and

    389.3. EA price sensitivity scenarios to provide an estimate of the change in price in each trading period, given various magnitudes of changes in demand.[388, 389]

390. This data allows us to estimate the proportion that Unit 2's output comprised of total national generation in a given trading period between 7 April 2023 – 4 April 2025.[390] We then match each trading period to an appropriate demand change scenario by:

    390.1. Estimating the percentage of total national generation in a trading period that was generated by Unit 2.

    390.2. Rounding this proportion to the nearest demand change scenario. For example, if Unit 2 generated 2.1% of total generation in a trading period, we would match this to the 2% scenario.[391]

    390.3. Assigning the price change that is modelled to occur in that matched scenario to the trading period.

391. As shown in Table 1, we find that removing Unit 2 would have increased the wholesale electricity price by 26.6% – 28.9% on average in trading periods where Unit 2 was dispatched, and by 11.8% – 13.2% on average across all trading periods.

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386 EMI "Wholesale datasets: Unit_level_generation_IR" (5 September 2025) <www.emi.ea.govt.nz>.

387 EMI "Wholesale datasets: Generation output by plant" (18 September 2025) <www.emi.ea.govt.nz>.

388 The EA considers price sensitivity with respect to volume changing by -5%, -4%, -3%, -2%, -1.5%, -1%, -0.5%, 0.5%, 1%, 1.5%, 2%, 3%, 4%, and 5%. EMI "Sensitivity of price to changes in load" (2 December 2024) <www.emi.ea.govt.nz>.

389 We use real time data for the North Island.

390 Due to data availability, we exclude the following dates from our analysis: 7 July 2024, 22 October 2024, 16 November 2024, and 14-21 January 2025.

391 We consider that the EA's scenarios which increase demand is a sufficient proxy for measuring the effect of an equivalent reduction in supply. In theory, given the supply stack is unchanged, the scenarios are effectively equivalent. In both cases, vSPD effectively identifies the next cheapest combination of offers to dispatch the required volume, with the resulting price being the marginal offer. We note that in practice, differences in the shape of the demand and supply curve may affect the accuracy of this proxy.

Table 1 Estimated effect on price of removing Unit 2 at Huntly between 7 April 2023 – 4 April 2025

	Dollar increase in price	Percentage increase in price
Average price change (all trading periods (**TP**)[392])	$19.7	11.8%
Weighted Average price change (all TP)	$22.9	13.2%
Average price change (TP Unit 2 dispatched)	$63.2	26.6%
Weighted Average price change (TP Unit 2 dispatched)	$70.1	28.9%

Source: Commerce Commission analysis of EA data

392. NERA's model implicitly considers the price increase across all trading periods by applying the price change to total annual generation. Therefore, we consider the 11.8% – 13.2% range to be the appropriate comparison to NERA's model.[393]

393. Our estimated range suggests that NERA's assumption that prices increase by 10% in year 1 then 12% in years 2 and 3 are suitable. Consequently, we are satisfied that our approach is consistent with NERA's estimated range for the public benefit that arises due to lower wholesale prices in the factual. While NERA's assumed price increases are on the lower end of our estimated range, this enables us to consider NERA's analysis to produce a more conservative estimate.

394. As a sensitivity, we adjust NERA's analysis to take a more conservative view on the retail elasticity of demand, where we assume these elasticities remain unchanged in future years.[394] Under this sensitivity, we still find a net consumer surplus benefit in the range of $5.4m – $5.8m.[395] This sensitivity does not affect the magnitude of any transfer of surplus from producers to consumers.

395. This sensitivity intentionally produces a conservative estimate; we accept NERA's argument that retail elasticities are likely to increase over a longer period due to a greater ability for interested parties to react to the supply-side shock of Unit 2's removal.[396] A conservative estimate, however, allows us to account for other uncertainties in the model, and, in any event, still identifies a sizeable public benefit.

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392 All electricity transactions are settled in 30-minute increments called trading periods (**TPs**).

393 Our estimation of the average effect in all TPs includes TPs where no effect occurred. Consequently, we account for Unit 2 only being dispatched approximately 30% of the time over our analysis period.

394 NERA's retail elasticity of demand parameters affect the change in dispatched generation as a result of the change in price.

395 For simplicity, we assume the factual price in years 4 and 5 remains unchanged from Concept's year 3 factual price. We then estimate years 4 and 5 counterfactual prices by applying NERA's estimated price change scenarios, which can be found in Annexure 1 at Table 1.

396 Annexure 1 at [28]-[29] and Appendix A.

Qualitative considerations for the appropriate magnitude for consumer surplus benefit

396. While our alternative approach suggests that NERA's assumed range for the effect on price is reasonable, there are a range of qualitative factors and assumptions/ limitations to each model that affect our interpretation of the results. Each affect the appropriate magnitude of this proposed public benefit.

397. We consider that the modelling may overstate the public benefit in several ways:

    397.1. We do not account for any delays in, or partial, pass through of wholesale prices to retail prices. Each would reduce the gain in consumer surplus during the analysis period.

    397.2. Our analysis uses data from the past 2 years which reflects dry year conditions in which it is likely that Unit 2 was used more frequently, and prices were more volatile than average. Our estimate of the average effect in all trading periods, which we place the most weight on, is positively correlated with the frequency that Unit 2 was dispatched.

    397.3. The price sensitivity scenarios reflect the immediate price impact in individual trading periods. Over the medium to long run, we would expect this effect to reduce as the market is better able to react to the supply shock of Unit 2 being removed, for example through new investment.

398. However, these factors must be weighed up against several factors that may mean we understate the public benefit. These include:

    398.1. NERA only modelled a five-year period, while authorisation is sought for 10-years. Concept estimate that wholesale prices may be on average 6% higher in the counterfactual by the end of the authorisation period.[397] We have not attempted to model the impact of this on consumer surplus given uncertainty in how the market will develop, and being unavailable for price sensitivities over a longer-time horizon. However, we expect that if prices remained on average lower in the factual beyond the initial 5 years that NERA modelled, a meaningful magnitude of public benefit would be attained.

    398.2. NERA only calculates one portion of the consumer surplus benefit because modelling the supply and demand curves in each half hour trading period in both the Factual and Counterfactual was beyond the scope of their report.[398]

399. While NERA's approach excludes the effect of hedging, which may reduce the 'effective price' paid for wholesale electricity and therefore affect the flow through of higher wholesale prices to consumers, we consider this is only relevant in the short run. New hedge contracts are priced to reflect expectations of future spot prices, and so over time, new hedge contracts would price-in the effect of removing Unit 2. Therefore, the exclusion of hedges in this modelling is only relevant with respect to hedges agreed

397 Annexure 1 at [26].

398 Annexure 1 at [20].

prior to the market pricing-in the effect (or expected effect) of the retirement of Unit 2.

400. Additionally, NERA only considers Concept's estimate of the price effect of removing a Rankine Unit under average weather conditions.[399] The true price effect of removing Unit 2 depends on the frequency of dry years we experience over the period authorisation is sought for. For, example, [ ].[400] However, despite this, we consider that using an average scenario is suitable. Given uncertainty regarding the frequency of dry years that will occur, it is not feasible to assign robust weights to any particular likelihood of more or less adverse weather conditions occurring.

401. On balance, we consider that average wholesale electricity prices are likely to reduce as a result of the Proposed Arrangements and that this will produce sizeable consumer surplus benefits.

402. Even if we exclude benefits arising from the transfer of surplus from producers to consumers on the basis that this constitutes a neutral transfer, we consider the public benefit of the Proposed Arrangements could fall in the range of $13.5m – $15.8m over the next five years.

403. While we acknowledge that each of the modelling approaches of NERA and the Commission may overstate the public benefit in some ways, each underestimates the effect in others. On balance, we consider that these effects are likely to cancel out to some extent, and we see no reason to consider it likely that the magnitude would be materially diminished by any of these factors. We take further comfort that this public benefit would be sizeable given that we still identify a public benefit of $5.4m against our conservative estimate.

404. We are not currently minded to place weight on public benefits arising from a transfer of surplus from producers to consumers, as submitted by NERA on behalf of the Applicants.[401] While we are satisfied NERA's estimated range of this potential surplus transfer is appropriate (for the same reasons we are satisfied with NERA's estimation of the gain in consumer surplus), such a transfer reflects a reallocation of surplus within the economy rather than the creation of new surplus. We therefore consider such a transfer to be a neutral transfer.

405. We consider weight should be placed on the creation of new surplus, rather than on a reallocation of existing surplus. In addition, as discussed above, we are satisfied that the creation of new consumer surplus already produces a sizeable public benefit.

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399 Annexure 1 at footnote 8.

400 Commerce Commission assessment of Applicants "Annexure 7: Confidential letter to Genesis from Concept Consulting on the effect of retiring Unit 2 dated 25 July 2025" (4 August 2025) at Table 1. [

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401 Annexure 1 at [30] and Table 2.