MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

COVERSHEET

Minister	Minister Watts	**Portfolio**	Energy
Cabinet paper	Government Investment in Dry Year Risk Cover: Consideration of an LNG Import Facility	**Date to be published**	10 February 2026

List of documents that have been proactively released		
Date	**Title**	**Author**
December 2025	Government Investment in Dry Year Risk Cover: Consideration of an LNG Import Facility	Office of the Minister for Energy, MBIE
15 December 2025	Government Investment in Dry Year Risk Cover: Consideration of an LNG Import Facility	Cabinet Office

Information redacted **<u>YES</u> / NO** *[select one]*

Any information redacted in this document is redacted in accordance with MBIE's policy on Proactive Release and is labelled with the reason for redaction. This may include information that would be redacted if this information was requested under Official Information Act 1982. Where this is the case, the reasons for withholding information are listed below. Where information has been withheld, no public interest has been identified that would outweigh the reasons for withholding it.

Some information has been withheld for the reasons of:

- Commercial information
- Confidentiality
- Confidential advice to Government
- Legal professional privilege

Annex 3 of the Cabinet paper (*Exploring the Case for LNG*), in addition to having some information redacted, has been edited for clarity since being considered by Cabinet.

Commercial In Confidence

Office of the Minister for Energy

Cabinet Economic Policy Committee

Government Investment in Dry Year Risk Cover: Consideration of an LNG Import Facility

Proposal

1 This paper sets out the case for proceeding with procurement of a liquefied natural gas (LNG) import facility and seeks agreement to create enabling legislation.

Relation to government priorities

2 Development of an LNG import facility will be a significant step in ensuring secure and affordable electricity supply by providing certainty of fuel supply for electricity generation in the face of declining domestic gas supply. It is also likely to support wider energy security of supply, by partially mitigating the impact from the decline of domestic gas supply for all gas users and enabling them to make choices about their future energy needs.

Executive Summary

3 The most pressing problem for our electricity system is a shortage of electricity generation that can take over in a dry year,[1] particularly given the rapid decline in domestic gas supply. This is driving up energy prices and creating material risks for households, businesses, and the wider economy.

4 In response, Cabinet agreed in September 2025 to an Energy Package which included commencing stage one of procurement for an LNG import facility to provide reliable dry year fuel supply. Having now undertaken an initial assessment of market responses, and further analysed the case for LNG, this paper seeks agreement to progress proposals for accelerated delivery of an LNG facility and enabling legislation.

5 The case for LNG is strong. Analysis shows LNG stacks up well against alternatives for providing dry-year cover. A key advantage of LNG is that it simply adds a fuel option without locking in new generation capacity or involving direct intervention in the electricity market. Moreover, it also offers the following advantages:

5.1 **Lower electricity prices:** The mere availability of LNG as dry-year insurance cover is expected to reduce forward electricity contract prices by at least \$10/MWh, saving consumers around \$400 million annually—materially outweighing the anticipated \$2.05-\$4.10/MWh levy[2] to recover its costs.

5.2 **System resilience:** It provides up to 1.5 TWh of backup energy, reducing extreme spot prices and supporting renewable investment.

[1] A 'dry year' is a period of weeks to months with low hydro lake inflows, often accompanied by low wind. In these periods, a greater portion of our electricity needs to come from non-weather dependent generation.
[2] Estimates based on early-stage procurement information. This may be missing some costs.

5.3 **Gas market stability:** It acts as a safety net for industrial users and extends the viability of gas networks.

6 LNG should function as an insurance product—available when required but used only infrequently. Over-reliance on LNG could link domestic gas prices to global markets, increasing costs for consumers. To mitigate this, the LNG solution will need to be of sufficient scale to allow fewer, larger shipments that can be called on only when needed. Gas market transparency will be strengthened, and efforts to bolster domestic gas supply will continue in parallel.

7 Under the proposed procurement model, the Government would contract for an LNG import service. An infrastructure provider would own and operate the facility, meaning the Government would not face any upfront capital costs.

8 Stage one of the procurement process closed on 17 November 2025 with 25 registrations of interest (ROIs) and [redacted] accelerated proposals claiming capability to be operational by winter 2027. I recommend investigating a shortlist of these with a view to entering into a contract with the preferred supplier of LNG facility services by mid-2026. If these prove infeasible, we will have the option of moving to a full Request for Proposal process.

9 An Enabling Liquefied Natural Gas Bill will be required to provide consents, approvals, and levy powers. Timing is tight Confidential advice to Government [redacted] This will require high legislative priority and possibly urgency.

Background – context and the dry-year insurance problem

The Government announced a package of measures, including LNG procurement, to address energy security and affordability

10 Energy underpins New Zealand's economy, but this foundation is now at risk from rising costs and supply insecurity. By 2025, higher energy prices are estimated to have reduced gross domestic product by $5.2 billion (1.25%), lowered real wages by 1.4%, cut household spending by 1.65%, and worsened the trade balance by $275 million. A recent Electricity Authority survey found that four in ten households and one in three small businesses are not confident they can afford their power bills over the next six months.

11 In September 2025, Cabinet agreed to an Energy Package, *Securing New Zealand's Energy Future,* to enhance energy security and affordability. This included commencing procurement for an LNG import facility to provide reliable dry-year fuel supply and ensure existing firming plant has the fuel to operate when needed. Cabinet requested a report-back in December 2025 for decisions on whether to proceed with an LNG import facility following testing of market interest and proposals.

Our electricity system lacks insurance to cover a dry year

12 The most pressing problem for our electricity system is a shortage of electricity generation that can fill the gap in a dry year. While the dry-year problem has been a longstanding risk, it has been seriously exacerbated by the decline in gas supply, with

2025 gas supply half what it was expected to be just three years ago. The result is that, while we have enough gas-fired generation plant to cover a dry year, we do not have enough gas to fuel it. This risk was exposed in 2024, as explained in Box 1.

Box 1: 2024 dry year

In 2024, hydro inflows were low, but far from the lowest on record. Normally thermal generation would kick in to slow the decline in our hydro lakes. But our gas plant lacked the fuel to run at capacity. Huntly Unit 5 (New Zealand's largest, most efficient gas unit) ran at only 65% over winter, despite the very high electricity prices that would usually prompt full dispatch.

Hydro lakes continued to fall faster than normal for a dry year, creating genuine security-of-supply concerns, because not enough thermal generation could run to arrest the decline. Spot prices exceeded $800/MWh—far above the marginal cost of coal/gas ($180) or diesel ($550), which would normally cap prices. Some industrial users paused operations; others closed permanently.

To keep the lights on, Methanex (our largest gas user) halted methanol production and sold gas to Genesis and Contact for electricity generation— Commercial Information Meridian also triggered a demand-response contract requiring the Tiwai aluminium smelter to reduce electricity consumption.

We were 'lucky' in 2024 in some respects. In 2023 (a wet year) two of our ageing thermal generation plants had significant outages. If this had happened in 2024 with its dry conditions, the situation would have been far worse.

13 Because there is no clear back-up supply or plan for a dry year, the market is pricing in the risk of shortages or the risk of needing to do very expensive deals. This is reflected in forward electricity contract prices, which include a $30–$50/MWh risk premium. As a result, the risk of high spot prices in a dry year flows through into electricity bills every year, putting pressure on the cost of living and slowing the economy.

14 In contrast, if the market had confidence that sufficient cover existed for a dry year, forward prices would fall—and so would electricity bills. Put simply, dry-year insurance would lower forward prices.

We need up to 1.5 TWh of additional dry-year insurance

15 Estimating the amount of dry year cover we need is challenging; it will evolve over time and depends on a range of uncertainties. We want enough cover to give the market confidence that a typical dry year can be managed—reducing forward prices—but not so much that the costs (in effect, the insurance premium) outweigh the benefits.

16 A range of different estimates suggest cover in the order of 3 TWh would be appropriate for insuring against a significant three-month dry period. A new agreement by the four gentailers to maintain three coal fired Rankines at Huntly could provide up to half of this (a maximum of 1.5 TWh).

17 I consider that additional dry-year cover that provides up to 1.5 TWh makes sense, recognising the uncertainty of domestic gas production, tCommercial Information and acknowledging our existing thermal kit

is ageing and prone to significant outages. In the same ballpark, Boston Consulting Group estimates that increasing long-duration firm energy by 1.1 TWh would provide additional security and ensure dry periods can be met affordably.

Commercial Information

18 In addition, Gas Industry Co has commissioned PwC to prepare the 2025/26 Gas Supply and Demand study. Commercial Information While the report is still being finalised, initial modelling shows there is likely to be insufficient gas supply from 2027 – especially in dry years when thermal generation is highest.

Analysis – the case for LNG

19 This section sets out the case for LNG compared with other options. It outlines the expected benefits and costs of LNG including spillover impacts.

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LNG is a strong option against alternatives for dry-year insurance

20 Before deciding to proceed with the procurement of an LNG import facility, we need confidence that it is the best option to provide dry-year cover, having regard to its cost, timeliness, impact on electricity prices, and wider impacts (for example, price effects on the domestic gas market).

21 Annex 3 *Exploring the case for LNG* assesses potential options to provide dry year cover. From an initial long list of 11 options, five were shortlisted as meeting the minimum requirement of delivering about 1.5 TWh of energy on demand over three months within the next five years:

21.1 LNG (import facility) option – able to provide 12 PJ over three months

21.2 Illustrative Rankine option – building a new coal/biomass-fired power plant

21.3 Illustrative Peaker option – installing new diesel generators and converting some existing gas units to run on diesel

21.4 Low-capex portfolio option – combination option maximising use of existing equipment and infrastructure

21.5 Additional cover portfolio option – LNG import facility, plus the gas-fired Taranaki Combined Cycle plant refurbished to increase generation capacity.

22 The analysis shows LNG is a strong option compared to alternatives (see Annex 1 for a one-page comparison). It is expected to lower electricity prices at relatively low capital cost and deliver spillover benefits (see next section). A key advantage of LNG over alternatives is that it simply adds a fuel option without locking in new generation capacity or requiring direct intervention in the electricity market (which would be more likely ‘crowd out’ private sector investment).

Expected benefits and costs of proceeding with LNG

The availability of LNG as dry-year insurance is expected to materially reduce electricity prices

23 In New Zealand, the price most users pay for electricity is set through forward contracts, not daily spot market prices. LNG availability could lower these forward prices by at least $10/MWh,[5] saving New Zealanders at least $400 million a year. This is because:

23.1 the risk of high spot prices during dry years adds a $30–$50/MWh risk premium to forward contracts every year, and

23.2 LNG generation costs about $200–$250/MWh, which has the effect of significantly reducing spot prices to around this level during dry years (spot prices may still exceed this price in severe years, where demand response or diesel-fired generation are required).

[5] BCG modelling indicates that for scenarios that include firm fuel, such as LNG, contracting premiums are projected to trend toward about $10 per MWh, reflecting reduced exposure to dry-year risk and greater confidence in fuel availability (Energy to Grow: Securing New Zealand's Future, November 2025)

24 Modelling of spot prices for 2028 and 2035, with and without LNG availability, supports this conclusion. In most scenarios, LNG reduces spot prices in both normal and dry years (see Annex 2). LNG delivers two key benefits: (i) having a capping effect on spot prices at LNG's marginal cost, and (ii) enabling greater use of low-cost hydro generation when operators have confidence in reliable back-up. The latter means that certainty of gas back-up promotes increased renewable generation.

25 Modelling indicates that in the most likely scenarios,[6] LNG would be likely to lower average electricity spot prices in 2028 by $58/MWh (if a dry year) or $10/MWh (if a normal year). By 2035, the modelling shows LNG reduces spot prices in all scenarios modelled.

26 Some commentators argue that LNG could increase electricity prices. Annex 2 shows there are scenarios modelled where this occurs—specifically, when domestic gas prices are tied to LNG prices and LNG would not otherwise have been required. This highlights a crucial design principle: LNG imports must be structured so they occur only when needed (for example, in a dry year or if domestic gas is in structural shortage), ensuring domestic and international prices are not linked unnecessarily. Put simply, LNG should function as an insurance product: available when required but used only infrequently. Perhaps counterintuitively, LNG provides the greatest benefit when it is available as back-up and rarely used.

The expected benefits significantly outweigh the costs

27 Findings from stage one procurement[7] suggest the cost of LNG infrastructure might be between $90 million and $180 million per annum for 15-20 year projects. Previous investigations into LNG import facilities suggest a cost of approximately Commercial Information [redacted]

28 Based on these estimates, if recovered through an electricity sector levy the cost would fall somewhere between $2.05/MWh and $4.10/MWh. A levy would effectively be an insurance premium for system security (see financial implications section for details). Compared to the anticipated reduction in forward electricity prices of at least $10/MWh, this delivers an indicative benefit-to-cost ratio of 2.4-4.9, in terms of forward price reductions alone—meaning consumers stand to gain significantly from the investment, though price savings.

LNG delivers spillover benefits

29 LNG can strengthen the domestic gas market by acting as a back-up supply during periods of structural shortage. Its availability reduces the risk of severe price spikes and supply disruptions, giving industrial gas users confidence to maintain operations. LNG provides a safety net for these users, ensuring continuity of supply when domestic gas is scarce. This helps avoid de-industrialisation as domestic gas production declines, and enables users to take time to consider their best, long-term energy solutions.

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[6] Based on officials view of the most likely scenario for the electricity market and then modelled by Concept.

[7] The costings provided by respondents through the procurement process all include significant caveats so should be considered indicative only.

30 LNG could also extend the viability of gas networks. Without LNG, supply decline could lead to underutilisation of gas networks, making them uneconomic and accelerating their decommissioning.

31 Gas sector participants (including Todd and others) have stated that LNG could support domestic gas by sustaining demand (reducing short-term closures) and keeping pipelines economically viable. In other words, LNG could help ensure there is off-take for any new gas finds. Importantly, LNG is not a substitute for strengthening domestic gas supply. As with electricity, it is an insurance product that complements the Government's broader work to support the gas market, by providing optionality and resilience.

32 LNG is also expected to support increased investment in renewables by providing reliable backup supply, which renewable developers need to make their projects bankable.

33 By reducing the risk of high electricity prices and uncertainty around security of supply, LNG can also be expected to ease concerns that commercial and industrial consumers may have around electrification.

34 Market commentators report there is increasing support across electricity and gas market participants for LNG. They cite the supporting role that LNG could play by bringing a ceiling to gas and electricity prices and supporting firming of both existing and new renewable generation build.

Procurement of an LNG import facility on an accelerated delivery model

Stage one of procurement has yielded [redacted] proposals for early delivery

35 Stage one of the procurement process closed on 17 November 2025. MBIE invited ROIs from parties interested in providing and operating LNG infrastructure. Respondents were also invited to submit accelerated proposals – a service that could start by 1 June 2027.[8] MBIE received 25 ROIs. Commercial Information [redacted] All proposals needed to meet a minimum requirement of delivering at least 12 PJ over any three-month period (sufficient to provide 1.5 TWh of electricity generation). Commercial Information [redacted]

8 Commercial Information [redacted]

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Commercial Information [redacted]

Early analysis suggests an accelerated delivery solution could be viable

36 MBIE is prioritising analysis of the accelerated proposals, which are generally high quality and include substantial analysis of factors such as the marine environment and port impacts (though further assessment and design work will be required). While many of the accelerated proposals appear to be strong candidates, each carries risks and issues. The proposals use different technical configurations and have varying characteristics. For example, while all involve using Port Taranaki services, options range from offshore facilities to major changes to port infrastructure.

37 My current view is that government should investigate a small number of the strongest accelerated proposals in the first part of 2026. Commercial Information [redacted]

38 I am seeking to set up a Ministerial group to assist the process. Confidential advice to Government [redacted]

[9] The implication of this is that it may not be possible to meet the June 2027 deadline specified in the ROI. I intend to investigate this further.

Legislative approach for accelerated LNG proposals

39 If Cabinet agrees to proceed with accelerated proposals, the preferred option will require a range of consents and approvals (including, for example, under the Resource Management Act 1991). Our objective is to provide as many of these approvals as possible before the election to give the preferred supplier greater policy certainty that New Zealand is committed to developing the facility. This will also reduce any risk premium during contracting.

40 I propose developing an Enabling Liquefied Natural Gas Bill to provide the necessary consents, approvals, levy power and any modifications to existing legislation to enable the preferred LNG facility to be built and operational ahead of winter 2027.

41 Confidential advice to Government [redacted]

42 Confidential advice to Government [redacted]

43 Confidential advice to Government, legal professional privilege [redacted]

44 Confidential advice to Government [redacted]

45 Confidential advice to Government [redacted]

46 Confidential advice to Government [redacted]

Confidential advice to Government [redacted]

Risks and mitigations

47 Developing an LNG import facility can provide important dry year insurance, but it comes with risks that need careful management. The timing is very tight from both a contractual and a legislative viewpoint, and LNG import facilities are highly technical in nature. Further, New Zealand does not have an ideal location (large deep-water port close to the main gas pipeline) to locate an LNG import facility, meaning that the technical challenges of importing LNG here are more significant than in some other countries. The key risks and their mitigations are set out in the table below.

Risk	Mitigation
Linking NZ to global gas prices: Over-reliance on LNG (using LNG when it's not a dry year or when the gas market is not in structural shortage) exposes New Zealand to geopolitical risk and global price volatility.	• Import model designed to be of sufficient scale to allow gas to be imported in fewer, larger shipments and stored for seasonal needs, rather than relying on LNG being 'drip-fed' into the New Zealand system in small continuous shipments. • Continue work underway to strengthen gas market transparency and reporting, to ensure competitive and transparent upstream gas markets to prevent supply distortions. • Continue efforts to strengthen domestic gas supply and ensure alternatives like biomass and electrification continue in parallel, to create optionality, not dependency. LNG should be treated as an insurance policy, not the primary solution.
Construction and delivery risks: Risk LNG infrastructure is not in place before substantial industry exits.	• Undertake further technical analysis of leading proposals by experts before proceeding with a preferred proposal. Be prepared not to proceed with an accelerated proposal should further analysis suggest that the proposal(s) is/are unworkable.
Timing risks: risk of late project delivery, especially to deliver an accelerated proposal by June 2027.	• Provide consents and other approvals through the Enabling Liquefied Natural Gas Bill. Combined with the signing of contracts, this will allow construction to get underway. • Commercial Information [redacted] If necessary, options that would not be operational until later in 2027 or early in 2028 will be considered.
Government policy risk: Where a future government decides not to proceed with LNG Legal professional privilege [redacted]	• Seek to agree contract when possible (ideally end of Q2 2026). Contracts will include termination clauses. • Clear communications of the benefits of LNG, including information on how LNG lowers electricity prices and supports greater renewable development. • MBIE will be the contracting party on behalf of the New Zealand Government for the initial phase of the operation of the facility.[10]

[10] Most Respondents to the ROI specified that they wanted government as the New Zealand counter-party.

Legal professional privilege [redacted]	• Policy continuity cannot be guaranteed into the future due to Parliamentary sovereignty. However, clear communications of the benefits of LNG, including information on how LNG lowers electricity prices and supports transition New Zealand's transition to a lower carbon economy could support policy continuity. • Legal professional privilege [redacted]
Price risks: risk of unfavourable contract terms.	• Thorough review of proposals, including pricing, completed prior to entering into a final contract. • Maintain competitive pressure in the process as long as possible. Maintain the ability not to proceed should it not be possible to either overcome the technical challenges implicit in locating LNG infrastructure in New Zealand, or to agree suitable commercial terms.
Adverse stakeholder reaction: LNG likely to be opposed by environmental groups, some local interests, and some commentators, and potentially some in the legal community.	• Seek to identify champions who can clearly explain the need for dry year cover and the link to supporting renewable development.

Implementation

48 In order to progress the next phase of this work, I seek authorisation for:

48.1 The Minister for Energy to approve the shortlisting of respondents to participate in the ongoing procurement process, as well as design of that process.

48.2 A group comprising the Minister of Finance, Minister for Infrastructure, Minister Responsible for RMA Reform, Minister for Resources, and Minister for Energy, to select a preferred respondent from that shortlist. If no suitable proposal emerges from this process, this group could also decide to run a wider request for proposals from firms who have completed the ROI process (this could see LNG delivery by 2029).

49 Confidential advice to Government

50 The indicative timeline for completing procurement of an accelerated proposal and progressing legislative changes is set out below.

Indicative Date	Action
After 17 December 2025	• Minister for Energy selects shortlist (six to eight) of proponents for further investigation.
January 2026	• Government announces decision to procure LNG facility. • Shortlisted respondents provide updated proposals for consideration. • Confidential advice to Government
February 2026	• Draft contract shared with the selected respondents to support commercial discussions. Two or three respondents selected from shortlist and invited to provide a final technical proposal and final costings.
March 2026	• Check-in with ministerial group regarding progress of procurement Confidential advice to Government
Confidential advice to Government	• Respondents submit final technical proposals and contract mark-ups
	• Final prices received from selected respondents
	• Ministerial group makes final decision on whether to proceed with an accelerated proposal. • Preferred respondent selected and contracts signed.
	• Legislation passed.

51 In parallel with the above work programme, MBIE will also develop an operating model for the management of the facility contract and LNG supply.

Cost-of-living Implications

52 The proposals in this paper are intended to lower electricity prices by improving the security of the electricity system during dry years.

Financial Implications

53 I propose recovering the cost of an LNG import facility through an industry levy. As outlined in the Stage 1 Cost Recovery Impact Statement (CRIS) (Appendix 4 refers), an LNG import facility would help keep forward contract prices down and provide a capping effect on spot prices in dry years, benefiting all electricity consumers.

54 In contrast, recovering costs through commercial arrangements instead of a levy would add \$5–\$22 per GJ to the price of gas (charged as a “re-gas” fee per GJ processed), making LNG uneconomic and undermining its role as an insurance policy. Because implementing a levy requires regulatory authority, LNG infrastructure cannot be delivered through a market-led approach.

55 Under the proposed model, the Government would contract for an LNG import service. The infrastructure provider would own and operate the facility, and the Government would pay an annual charter fee and would not face any upfront capital costs. Financial implications are set out below:

Component	Illustrative Costs	Funded by
Annual charter fee to recover Whole of Life Costs [redacted]	$90-180 million for 15 years – to be recovered by levy	Levy set between $2.05/MWh and $4.10/MWh levy on electricity generation (potentially offset with commercial revenue)
LNG Supply	$20-25/GJ Total Cost to user[11]	Commercial sales to generators and direct users
Working capital	Unknown, may not be required	Crown, could be included in levy recovery

56 The levy in this example, if fully passed through and without any off-setting commercial revenue, would add around $15-$30 to the average annual household electricity bill (but is expected to be more than offset by lower electricity prices as discussed above).

57 I propose that the enabling power for a levy in legislation be set broadly – to support activities and services associated with LNG infrastructure and importation. This would minimise fiscal risks, and enable more detailed design in regulation.

58 I intend that the levy be charged on a per MWh basis and established within, or designed to sit alongside, the current Electricity Industry Levy under the Electricity Industry Act 2010. This framework would enable a single transaction, to ensure cost-effective collection. There may also be a case to recover from gas users in the future, so this will be enabled in the design of the Bill.

59 The levy will also be designed so that adjustments can be made each year for commercial revenue collected, and variations in actual expenditure (past and anticipated) to be smoothed if appropriate.

60 In practice this means the levy process could be as follows:

60.1 A formula for the levy set out in regulations (either as a line of activity in the Electricity Industry Levy, or in a set of LNG cost recovery regulations).

60.2 Each year this will be calculated based on actual costs, any revenue received, and other adjustments as required. The rate for the year will then be gazetted.

60.3 Electricity sector participants (potentially generators or retailers) will then be invoiced for the LNG levy, as part of or alongside the Electricity Industry Levy.

61 Further work refining the detail of cost recovery is required, particularly the role of commercial revenue (and/or direct gas sector contribution), and scope and scale of

[11] This is comprised of: $13-17/GJ for LNG supply based on forward market estimates + $3/GJ ETS costs + [redacted] storage and transmission + [redacted] re-gas costs

costs. This next level of detail will be included in developing regulations and will include sector consultation and a Stage 2 CRIS analysis.

62 If the administration of the LNG facility contract remains with MBIE, we will need to establish a levy-funded appropriation. Confidential advice to Government [redacted]

63 The Financial Case section of *Exploring the case for LNG* in Annex 3 provides further detail.

Legislative Implications

64 Should the Government decide to progress with procuring an LNG import facility through an accelerated proposal, it will likely need to provide the necessary consents, approvals or modifications to enable the facility's construction and operation. Legislative authority would also be needed for a levy to recover the facility's costs. These would be implemented through a new bill: the *Enabling Liquefied Natural Gas Bill*. Should the Government opt for a more standard procurement approach, enabling legislation will likely be required but detailed design would need to wait for completion of the RFP.

65 Confidential advice to Government [redacted]

66 The proposed Act would bind the Crown.

67 The Parliamentary Counsel Office has been consulted. Confidential advice to Government [redacted]

Impact Analysis

Regulatory Impact Statement

68 A RIS has not been prepared due to timeframes, and uncertainty about the scope of regulatory enablement required; note a SAR will be completed.

69 A Quality Assurance (QA) Panel with members from MBIE has reviewed the CRIS: Options for dry year risk cover – enabling cost recovery (attached). The QA Panel consider that the information and impact analysis summarised in the CRIS partially meets the Quality Assurance criteria.

70 The QA Panel notes that the CRIS is convincing, well-written and in response to a defined need, with risks and constraints identified and discussed. There is, however, a constrained analysis of options to address the problem and a lack of consultation, however there will be opportunity for public participation in the development of Regulations.

Climate Implications of Policy Assessment

71 The Climate Implications of Policy Assessment (CIPA) team has been consulted and confirms that CIPA requirements do not apply to this policy proposal, as the threshold for significance is not met. The proposal involves establishing an LNG import facility for dry-year electricity generation and modelling costs and emissions out to 2035. Counterintuitively, modelling shows New Zealand's emissions would be lower with an LNG import terminal than with no additional dry-year policy. The emissions impact of this proposal is a reduction of 0.244 Mt CO_2-e in EB2 and 0.04 Mt CO_2-e in EB3, driven by changes in the fuel mix for electricity generation across LNG, diesel, and coal. In the modelling, LNG storage enables more hydropower over the course of the year, instead of needing to reserve it for dry-year risk. This reduces coal use on the grid and resulting in lower emissions compared to a scenario without an LNG import terminal, where more fossil generation is used throughout the year to preserve hydropower for dry-year risk. Although this proposal does not meet the CIPA threshold, its importance to the energy system has prompted extensive modelling. The CIPA team has reviewed the estimates at a high level and considers the modelling to follow good practice and use reasonable, balanced assumptions.

Population Implications

72 There are no specific population implications from this proposal.

Human Rights

73 There are no human rights implications.

Use of External Resources

74 MBIE engaged specialist expertise to undertake modelling and analysis of LNG impacts under various scenarios, to support MBIE's consideration of the case for an LNG import facility. The cost of this engagement was approximately [redacted] (excluding GST).

75 MBIE is also engaging expertise to support the LNG procurement process. This includes domestic and international legal expertise, and LNG technical expertise (to assess feasibility of proposals). MBIE estimates that the cost of procurement up until closing the contract with the supplier will be up to [redacted]. MBIE will seek to run the procurement process within the available budget but there is a risk that additional funding will be required

Consultation

76 This paper was prepared by the Ministry of Business, Innovation and Employment. The Treasury, Ministry for Regulation, Ministry for the Environment, Ministry of Foreign Affairs and Trade, and the Infrastructure Commission were consulted. The Department of the Prime Minister and Cabinet was informed.

77 [redacted] Confidential advice to Government

Confidential advice to Government

77.2 Confidential advice to Government [redacted]

Ministry of Foreign Affairs and Trade comment

78 Legal professional privilege [redacted]

Communications

79 I intend to make an announcement on LNG shortly, in consultation with the Prime Minister's Office.

Proactive Release

80 I intend to release this Cabinet paper proactively in part, within 30 business days. Proactive release is subject to redaction as appropriate under the Official Information Act 1982. Commercially sensitive information will be redacted.

Recommendations

The Minister for Energy recommends that the Committee:

Background

1 **note** that in September 2025, Cabinet agreed an Energy Package aimed at ensuring security of supply and better functioning markets [CBC-25-MIN-0054 refers];

2 **note** that as part of this package, Cabinet agreed to commence the first phase of a procurement process for a Liquefied Natural Gas (LNG) import facility to secure 'dry year cover' for periods in which renewable generation falls short;

The case for LNG

3 **note** that, having compared LNG proposals against alternative options for dry-year cover, LNG is the preferred option;

[12] Legal professional privilege [redacted]

[13] Legal professional privilege [redacted]

4 **note** that the Ministry of Business, Innovation and Employment (MBIE) has completed a registration of interest to test market interest and capability in delivering an LNG import facility to meet New Zealand's needs (at least 12 petajoules of gas over any 3-month period);

Advancing the procurement process

5 **note** that two processes were initiated in the procurement exercise:

5.1 an accelerated delivery solution process designed to deliver an LNG import facility by 1 June 2027, and

5.2 a more traditional procurement process, which is estimated to result in LNG import infrastructure being available by winter 2029;

6 **note** that while many of the accelerated proposals appear to be strong candidates, further technical, commercial and financial analysis is needed to determine if any should be pursued;

7 **authorise** the Minister for Energy to select the most promising accelerated proposals for further investigation and make other decisions about the design of the procurement process;

8 **authorise** the Minister of Finance, Minister for Infrastructure, Minister Responsible for RMA Reform, Minister for Resources and Minister for Energy (the Ministerial group) to make final decisions on the selection of a preferred provider;

9 **note** that the Minister for Energy will ensure the Ministerial group is kept aware of progress on the project;

Enabling legislation for an accelerated solution and levy-based funding

10 **note** that an LNG terminal will require regulatory consents and approvals if it is to be operational ahead of winter 2027, and the existing Fast-track Approvals Act 2024 processes are unlikely to be sufficient;

11 Confidential advice to Government [redacted]

12 Confidential advice to Government [redacted]

13 **agree** to develop a new Bill, the *Enabling Liquefied Natural Gas Bill* (the Bill), to provide for the following:

13.1 the regulatory consents, permissions and legislative modifications to develop, maintain and operate an import facility, including flexibility to amend those consents and permissions or to add further consents and permissions if required;

13.2 a levy to recover the costs of an import facility and associated infrastructure and services;

14 **authorise** the Minister for Energy to:

14.1 make policy decisions to give effect to decisions 10 to 13 above;

14.2 approve any matters that arise during drafting and that may be required to align with the above decisions;

15 **invite** the Minister for Energy to issue drafting instructions to the Parliamentary Counsel Office consistent with the above recommendations;

16 Confidential advice to Government [redacted]

Financial implications

17 **note** the costs of the preferred option will depend on the outcome of negotiations with suppliers, but initial procurement submissions indicate a range of whole of life costs Commercial Information [redacted] paid for by a $90–$180 million per annum charter fee;

18 **note** that there may be scope for commercial revenue to partially offset some of these costs, and that commercial revenue is expected to fund the cost of importing the LNG itself;

19 **agree** that the remaining costs of development, maintenance and ongoing operation of the preferred facility should be met via a levy, reflecting the benefit of security of supply across the system;

20 **note** that while the levy is expected to fully recover costs, there is a residual fiscal risk to the Crown if levy recovery is delayed or costs escalate, and officials will manage these risks through contractual design and levy-setting mechanisms**;**

Next steps

21 **invite** the Minister for Energy to provide an update to the Ministerial Group in March 2026 regarding progress with procurement Confidential advice to Government [redacted] with a view to the Ministerial Group making final decisions related to recommendation 8 [redacted]

Authorised for lodgement

Hon Simon Watts

Minister for Energy

Annexes

Annex 1: At-a-glance comparison of options to provide 1.5 TWh of dry year cover

Annex 2: Modelling results: Impact of LNG on electricity prices under different scenarios

Annex 3: Options analysis and high-level business case for investment in dry year cover

Annex 4: Stage 1 Cost Recovery Impact Statement (CRIS)

Annex 5: Climate Implications of Policy Assessment

Annex 1: At-a-glance comparison of options to provide 1.5 TWh of dry year cover

	1. LNG import facility	**2. Illustrative Rankine option** *New power plant with 3 x 250MW Rankines which can use coal or biomass*	**3. Illustrative Peaker option** *New diesel peakers (300MW) and conversion of 400MW of existing peakers to diesel*	**4. Low capex portfolio option** *Rankine at Huntly; new and converted diesel peakers; demand response*	**5. Additional cover: LNG and Taranaki Combined Cycle (TCC)** *As per conventional scale LNG, plus TCC refurbished to provide additional generation capacity*
Timeliness	2027 - 2029 (incl. ship build & port works) depending on option *Fast option* *Score: 2*	2030 – 2033 *Slowest option with significant delivery risk* *Score: 5*	2028 *Fast option* *Score: 2*	2028 – 2030s (could be delivered incrementally) *Elements can be delivered quickly* *Score: 2*	2029 *Fast option* *Score: 2*
"Insurance premium" to recover capex	$2.05-$4.10/MWh *Moderate capex option* *Score: 3*	$8.20/MWh *Highest capex option* *Score: 5*	1.20$/MWh *Lowest capex option* *Score: 1*	$2.00/MWh *Low capex option* *Score: 2*	$4.50/MWh *Moderate capex option* *Score: 3*
Cost of generating electricity	$200-$250/MWh *Moderate generating cost – "insurance" puts downward pressure on forward contract prices* *Score: 2*	Coal = $150-170/MWh Biomass=$180 -215/MWh *Lowest generating cost – "insurance" puts significant downward pressure on forward contract prices* *Score: 1*	$510-$570/MWh *Very high generating cost – "insurance" puts minimal downward pressure on forward contract prices* *Score: 5*	Coal: $150-170/MWh Diesel: $510-$570/MWh Demand response unknown but higher than diesel *Moderate generating cost – "insurance" puts downward pressure on forward contract prices* *Score: 2*	TCC: $155 - $195/MWh Existing kit: $200-$250/MWh *Moderate generating cost – "insurance" puts downward pressure on forward contract prices* *Score: 2*
Flexibility • Maintains option value (can exit, if no longer needed) • Able to deal with different levels of demand, including to provide 1.5 TWh in an unexpected dry sequence	- Flexible delivery and adds 4PJ of storage – can readily provide 1.5 TWh over three months - Exit-able (FSRU can be sold) - Simply provides fuel option, so does not "lock in" generation *Score: 2*	- Locks in significant new generation capacity - Coal and biomass readily storable so can provide 1.5 TWh over three months *Score: 5*	- Locks in new generation capacity, but can be added incrementally - Amount of diesel required is significant (27% of NZ daily need) so storage needs to provide the necessary flexibility would be significant *Score: 4*	- Locks in new generation capacity, but can be added incrementally - Coal and diesel storable. Requires significant diesel storage to be effective as an insurance policy (but less than option 4) *Score: 4*	- As per option 1 for fuel source - TCC refurbishment locks in generation capacity *Score: 4*
Spillover costs	- Risk of exposure to international gas prices (however, domestic gas prices already approaching LNG prices) *Score: 3*	- Higher emissions than gas (lower for biomass) - Significant new generation plant impacts electricity market (cannot be delivered in small increments depending on need) *Score: 5*	- Higher emissions than gas - New generation capacity impacts electricity market incentives (lower impact than option 3 as can be delivered in increments) *Score: 4*	- As per option 3 - New generation capacity impacts electricity market incentives (lower impact than option 3 as can be delivered in increments) *Score: 4*	- New generation capacity impacts electricity market incentives *Score: 4*
Spillover benefits	- Less emissions than coal-fired generation - Potential industrial, and commercial use of LNG, maintaining access to gas for those businesses. *Score: 2*	- Ability to switch between different fuels improves resilience - Regional economic and employment opportunities assoc. with biomass - Would release some gas for other users (less than Option	- Limited spillover benefits	- As per option 3	- As per option 1

		1) *Score: 2*	*Score: 3*	*Score: 2.5*	*Score: 2*

*Score indicates relative ranking of the options against the criteria. Different weights may be applied to different criteria, and so totals are not provided.

Annex 2: Impacts of LNG on electricity prices in different future scenarios

MBIE commissioned modelling and analysis of LNG impacts. The modelling produced the following expected impacts of LNG on average New Zealand electricity spot prices under various scenarios, for illustrative 2028 and 2035 years. By simulating future operation of the electricity system the modelling predicts how the electricity system will likely develop over time, and forecasts the spot prices that could eventuate in that market. It does this for 43 possible "weather years" to give a distribution of spot prices. The modelling represents a collective "NZ Inc" approach, and does not capture individual participant behaviours.

	In 2028	**Expected impact of LNG on annual average NZ electricity spot prices ($/MWh)**	
	Scenario	**Median weather year (P50 price effect)**	**Dry year (P95 price effect)**
Scenarios where modelling indicates LNG reduces spot prices	Central case but only 2 Rankines	- $18 ($217 ➔ $199)	- $54 ($501 ➔ $447)
	Central case (ie MBIE view of most likely counterfactual): demand and supply out of balance, 3 Rankines, LNG price of $20/GJ	- $11 ($200 ➔ $189)	- $58 ($338 ➔ $280)
	Central case but with supply/demand better in balance	- $2 ($141➔ $139)	- $9 ($215 ➔ $206)
Scenarios where modelling indicates LNG increases spot prices	Central case but with Tariki storage and local gas prices tied to LNG price at $25/GJ	+ $20 ($175 ➔ $195)	+ $8 ($244 ➔ $252)
	Central case but with supply/demand better in balance, Tariki storage and local gas prices tied to LNG price at $25/GJ	+ $20 ($124 ➔ $144)	+ $20 ($181 ➔ $201)

	In 2035	**Expected impact of LNG on annual average NZ electricity spot prices ($/MWh)**	
	Scenario	**Median weather year (P50 price effect)**	**Dry year (P95 price effect)**
Scenarios where modelling indicates LNG generally reduces spot prices	Central case but demand/supply out of balance	- $3 ($141 ➔ $138)	- $44 ($328 ➔ $285)
	Central case (ie MBIE view of most likely counterfactual): demand and supply in balance, 2 Rankines, LNG price of $25/GJ	+ $1 ($93 ➔ $94)	- $42 ($256 ➔ $213)
	Central case but 3 Rankines	$0 ($96 ➔ $96)	- $32 ($222 ➔ $189)
	Central case but Tariki storage (and 2 Rankines)	+ $3 ($91 ➔ $94)	- $2 ($206 ➔ $204)

MINISTRY OF BUSINESS, INNOVATION & EMPLOYMENT
HĪKINA WHAKATUTUKI

Ministry of Business, Innovation and Employment

Exploring the case for LNG

Prepared by:	Energy Markets Branch
Prepared for:	Cabinet
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Contents

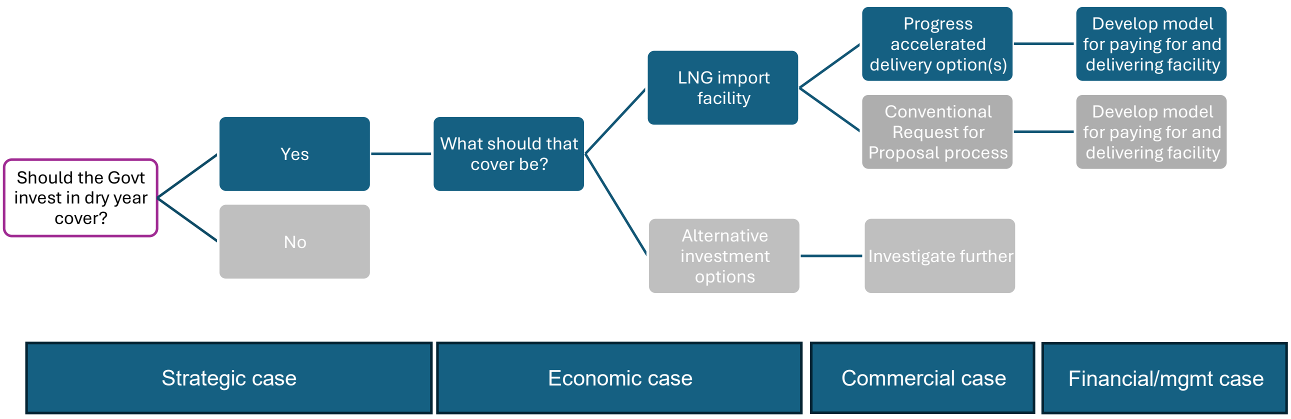
Introduction

This document sets out:

- The strategic context for the Crown procuring an additional source of dry-year electricity.
- The costs and benefits of a liquefied natural gas (LNG) import facility relative to alternative investment options (including the counterfactual).
- Proposed procurement/commercial approach to secure the project.
- Options for the funding and delivery of an LNG import facility (if pursued).
- Proposed management of the project once operational.

Timeframes for this analysis were constrained, meaning that a full business case was not feasible, and there has been no independent stage gate review. Nonetheless, the 'five cases' model provides a useful framework for analysing the need for, and costs and benefits of, an LNG import facility. This document therefore follows the overall structure of a single-stage business case.

The below flowchart outlines the high-level decision process required, and how they map on to the chapters in this document. The preferred option or pathway is in blue, with alternative options that have been considered in grey.



Summary

Energy underpins New Zealand's economy, but this foundation is now at risk from rising costs and insecurity. According to an estimate from Sense Partners, New Zealand's gross domestic product in 2025 will be $5.2 billion (1.25%) lower because of higher energy prices since 2017. Over the same time period real wages, household spending, and the trade balance will also be lower.

One of the drivers of higher prices is 'dry-year' risk. New Zealand's high reliance on intermittent renewable resources means that in periods where renewable generation is unable to meet demand (generally when hydro lake levels are low) we need to rely on other sources to 'firm' or complement renewables. Natural gas has previously been a key fuel source of that firming capacity but there have been increasing shortages of gas in recent years.

New Zealand experienced a dry period in winter 2024, when dry conditions (although far from the driest on record) coincided with an acute shortage of domestic gas, meaning that a deal had to be reached with Methanex (a large industrial user of gas). This option was expensive and may not be available in future years given the likelihood that domestic gas will be increasingly rare. At its 2024 peak, the average daily spot price of electricity reached a peak of $893.91/megawatt hour (MWh). This is significantly more than, the short-run cost of the most expensive form of generation: diesel at $510-$570/MWh.

Dry-year risk affects prices even in normal years. Australian Securities Exchange (ASX) futures contracts have been well above the cost of building new generation since 2018 when gas supply issues first emerged and have remained elevated despite the pipeline of renewable generation being delivered. A significant 'dry-year risk premium' is being baked into forward prices. MBIE (and some gentailers) estimate this premium at $30 to $50/MWh.

Our electricity market has taken some steps to address this problem, but is not well designed to fully cover dry-year risk on its own. Given the relative infrequency of dry years and high upfront costs of solutions that require new generation capability, individual participants in the market may make some investment, but there is insufficient incentive to fully address dry-year risk. The gentailers (Genesis, Mercury, Meridian, and Contact) have agreed to maintain a unit at Huntly Power Station as a strategic energy reserve for up to ten years. We estimate that Huntly covers approximately 50% of what would be required in a significant dry-year event.

As part of its Energy Package released in October 2025, the Government has committed to developing a regulatory framework to ensure a market-based solution for dry-year risk. The Government has also committed $200m to co-invest in gas market development. These actions will have some early benefits but are likely to have greatest impact on the electricity system from mid-2030s, given the lead times for these types of investments.

In the meantime, the combination of factors related to weather, fuel shortages driven by declining gas production, and aging thermal generation plant mean New Zealand remains exposed to dry-year risk. Through the Energy Package, the Government also committed to exploring the importation of LNG as a shorter-term dry-year cover solution.

There are a range of approaches taken to estimate how much firming capacity we would need for such cover, but they generally point to around 3 terawatt hours (TWh) over three months being adequate "insurance" cover for dry-year. Of this, the Huntly arrangement is expected to provide up to 1.5 TWh of cover, leaving another 1.5 TWh of cover remaining. As set out in the Frontier Economics Review of Electricity Markets, this portion of dry-year cover is unlikely to be provided by the electricity market.

MBIE has assessed LNG importation against four other illustrative options to provide that 1.5 TWh of additional capability. These illustrative alternative options involve building new generation infrastructure capable of running on non-gas fuel or converting existing gas generation infrastructure to a similar purpose.

Compared with alternatives, LNG appears an effective, and relatively low-cost solution that also provides a high degree of flexibility. MBIE's assessment is that LNG is least likely to "lock in" a particular form of generation, as:

- the import facility simply provides a fuel source for a specific term (around 15 years) and could be re-deployed if no longer required,
- LNG is unlikely to dampen existing incentives on market participants to invest in renewable generation, given the price point, and
- LNG offers spillover benefits in providing another form of gas supply to industrial gas users and reducing the risk of severe price spikes, which in turn gives these users confidence to maintain operations and consider their optimal, long-term energy solutions.

The key risks of importing LNG are that it may link the price of domestic gas to LNG, thereby exposing New Zealand to changes in the global market for LNG. These risks can be mitigated by an import model that ensures LNG is only delivered when domestic gas is tight, and through additional gas storage (which would be beneficial regardless of whether LNG was being imported). Modelling prepared for MBIE by Concept suggests that if imported on a sufficient scale (around 12 petajoules per three-month period), LNG would be expected to reduce spot prices by approximately $11/MWh during a normal year and by as much as $58/MWh during a dry year.

The net benefit of an LNG terminal is estimated to be at least $220m-$310m per annum for electricity users. BCG modelling suggests that the risk premium could be reduced by around $10/MWh if an LNG import facility were available – a benefit of $400m per annum for electricity consumers. The following table sets out the range of potential benefit, based on the $10/MWh estimate.

	Lower end of LNG import facility costs	**Higher end of LNG import facility costs**
Levy (for cost recovery of LNG facility annual fee)	$2.05/MWh	$4.10/MWh
Net forward price effect (saving)	$7.95/MWh	$5.90/MWh
Net annual savings in electricity costs to consumers[1]	$310 million	$220 million

Given MBIE estimates the risk premium to be $30-50/MWh, we consider a $10/MWh reduction to be conservative i.e. a lower bound.

The recently completed Registration of Interest indicated considerable interest from the market, with 25 responses received, including [redacted] accelerated delivery solutions (delivery in 2027). Should Cabinet decide to proceed with LNG, MBIE recommends proceeding with detailed technical assessment and commercial negotiations with a shortlist of the best accelerated delivery solutions. Should further investigation show these not to meet requirements, the Government would have the option of moving to a Request for Proposals from the qualified respondents to the Registration of Interest. The model for procurement of

[1] Includes households and firms

LNG itself will depend on the project selected. It is likely that this will run on a commercial model, though there may be an aggregation/facilitation role for the Crown.

Institutional arrangements on the Crown side for the delivery of the terminal will be developed in 2026, once the commercial process is further advanced, MBIE will continue as project owner, unless it becomes clear another model is appropriate given the operational requirements.

An LNG import facility would function similar to an insurance product, and therefore should be levy funded. The facility will provide savings in electricity costs to all electricity users (in proportion to their rate of electricity use) during both normal and dry years. Given this, MBIE recommends a per MWh levy as a way of funding the terminal's provision. Where possible, this may be offset by commercial revenue (a re-gas fee for LNG throughput). Further work refining the detail of cost recovery is required, particularly the role of commercial revenue (and/or direct gas sector contribution), and scope and scale of costs.

Assuming a whole of life cost of Commercial Information for the import terminal, this levy could be between $2.05/MWh and $4.10/MWh, although the final rate is subject to further design in 2026.

Legislation will be required to support delivery of the import facility. This includes enabling a levy, and to provide certainty about the relevant consents and approvals. Confide Confidential advice to Government The policy work regarding this is ongoing.

Strategic Case

Key points

- **Although difficult to quantify, New Zealand would benefit from an additional 1.5 TWh of electricity generation cover for significant dry periods, in addition to the recent agreement to support coal-fired generation at Huntly Power Station.**
- **The current constraint for electricity generation is the availability of fuel. In previous dry years we have relied on gas to provide the firming capacity needed, but the rapid drop-off in domestic gas supply makes that solution increasingly unreliable.**
- **It may not be in the interests of individual, profit-maximising firms to make significant investments that would only pay off over a series of unpredictable dry years (or critical outages).**
- **The Government has identified importation of LNG to address the fuel availability gap in the short to medium term (that is, until mid-2030s). Beyond that, the dry-year regulatory framework being developed is expected to provide a longer-term solution to the problem of incentivising investment (this ties to likely retirement dates of thermal plant). Any shorter-term solution should preserve market incentives to invest in additional generation capacity in the meantime.**
- **We would expect any effective solution to reduce the risk premium currently observed in forward prices (estimated at $30-$50/MWh). Net savings in price will be a combination of reduced risk premium and increased levy costs (proposed levy to recover costs of preferred option).**

Purpose of this strategic case

1. This section outlines the case for the Crown to procure some form of capability to generate electricity if required in a dry year,[2] in light of the rapid decline in domestic gas production. While this document as a whole responds to a recent decision by the Government to investigate LNG as dry-year cover, the focus of this section is whether there is a case for investment by Government. Analysis is limited to near-term investment, given that there is a separate workstream (Action 2.5 Dry Year Regulatory Framework) intended to address market failures in delivering dry year cover longer term.
2. The next section (the economic case) assesses potential investment options to provide cover against dry year risk in the medium term and meet the investment objective set out in this strategic case. Regulatory interventions are not in scope as the Government has previously made decisions about the suite of interventions it wishes to consider and Action 2.5 of the Energy Package considers longer term regulatory options.

[2] The term 'dry year' covers events of extended periods of weeks or months in which reduced rain and snowmelt, often accompanied by low wind, put pressure on the electricity system by reducing the availability of fuel for renewable generation.

3. This section includes:

- The background to the Government's decision to investigate an LNG import terminal.
- The problem definition, including an outline of the risks facing New Zealand's electricity system and how the counterfactual is expected to evolve without intervention.

Background and context

4. Predictable and low electricity prices are a determinant of overall economic performance as they are a key input cost for businesses and a growing share of household spending. Sustained energy cost increases have had damaging effects on the economy and households. Sense Partners has estimated that higher energy prices between 2017 and 2025 had the following impacts in 2025:[3]

- reduced New Zealand's gross domestic product (GDP) by $5.2 billion (1.25%),
- lowered real wages by 1.4%,
- cut household spending by 1.65%, and
- worsened the trade balance by $275m.

5. Households and small businesses are also under pressure. A survey for the Electricity Authority released in November 2025 indicated around four in ten households and one in three small businesses are not confident they can afford their power bills over the next six months.[4]

The electricity market signals the need for investment, but continues to be exposed to the 'dry-year problem'

6. Investment decisions in new generation are made by individual firms in a decentralised manner. Expectations of future payments for actual generation are the primary driver of investment in new capacity.

7. Both suppliers and customers aim to reduce revenue and cost risk with contract (or hedge) markets that provide more secure arrangements to underpin short-and long-term decisions.

8. New Zealand's electricity system is exposed to a dry-year problem – that is there is a shortfall in electricity generation for long periods, typically during winter, when rainfall is low, there are long calm periods (limited wind generation) and limited solar generation (renewable intermittent generation). This can best be addressed by having long duration, dispatchable electricity generation (firm generation). In New Zealand, and with current technologies, this typically requires thermal generation. New Zealand currently has a shortage of firm generation to reliably cover dry-year risk.

9. The dry-year problem, if not adequately addressed by firm generation, creates security of supply issues. This risk (even when it does not materialise) causes prices to be higher than they would otherwise be, as the market prices in expected dry-year price spikes (driven by shortages). That is sellers of a three-year contract will price the contract on the expectation that there will be at least one dry year in that period. These increased prices create affordability pressures for households and businesses.

10. The nature and scale of the dry-year problem is discussed in detail later in this strategic case, but an example occurred in the winter of 2024, when a dry year led to the average

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[3] Document Overview: sense-partners-historical-impacts-of-high-electricity-and-gas-prices-on-the-new-zealand-economy-and-industries-a-gsm-nz-dynamic-cge-analysis-20-july-2025.pdf

[4] 2025 Consumer Perceptions and Sentiment Survey Report

daily spot price reaching a peak of $893.91/MWh. From a hydrological standpoint, 2024 was not a particularly severe ‘dry’ year. However, the lack of available alternatives (limited gas for thermal generation) meant that spot prices increased significantly during a cold snap in early August.[5]

11. Overall, the system lost approximately 1.7 TWh of hydro generation during winter 2024.[6] The shortage of hydro power could not be offset by increased gas-fired generation to the same extent as previous periods simply because gas was unavailable. The market was able to avoid blackouts by calling on demand response from large energy users:

- Tiwai aluminium smelter significantly reduced its electricity use.
- Methanex, a large-scale gas consumer, agreed to halt production and sell its gas to Genesis and Contact for electricity generation.

The Electricity Market Review found the market will not address the dry-year problem

12. Following winter 2024, Cabinet commissioned (CAB-24-MIN-0245 refers) an external review into the performance of New Zealand’s electricity markets. The reviewers, Frontier Economics (Frontier), presented their report to the Government in June 2025.

13. Frontier found that New Zealand’s electricity market design is generally fit for purpose. The market is successfully incentivising new renewable generation investment, the vast and growing majority of New Zealand’s electricity supply and that this is likely to put downward pressure on prices over the longer term.

14. However, Frontier also found that the market is failing to deliver investment in firm fuel and long-duration dispatchable plant. This investment is essential to ensure supply when hydro, wind, and solar output fall short. Intermittent resources cannot guarantee supply during extended dry years or wind droughts unless generators decide to invest in capacity significantly above the level needed to provide electricity in a typical year.

15. Frontier identified four key problems driving this investment failure:

- *Gas supply risk*: declining gas production is causing a significant fuel availability risk.
- *Revenue risk:* it is risky, and becoming riskier as the share of renewables increases, to invest in plant that may not make money until a dry year.
- *Investor desertion:* there is an unwillingness to invest in thermal assets and fuels due to environmental, social, and governance considerations, and the risk of future government policy changes.
- *Free rider market failure:* uncertainties mean it is economically rational to wait for another generator to invest to improve the dry year situation, and purchase from them as required.

16. Frontier concluded that without definitive action by the Government, dry year risk will lead to increased prices, insecure supply, and economic disruption that will drive industry out of New Zealand.

Evidence supports the Review’s findings

17. The key insight from the Frontier report is that the market’s observed unwillingness to invest in dry-year cover is driven by a market failure that means it is not in the interests

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[5] Electricity Authority, ‘Review of winter 2024’. Link: Review of winter 2024.

[6] Confidentiality

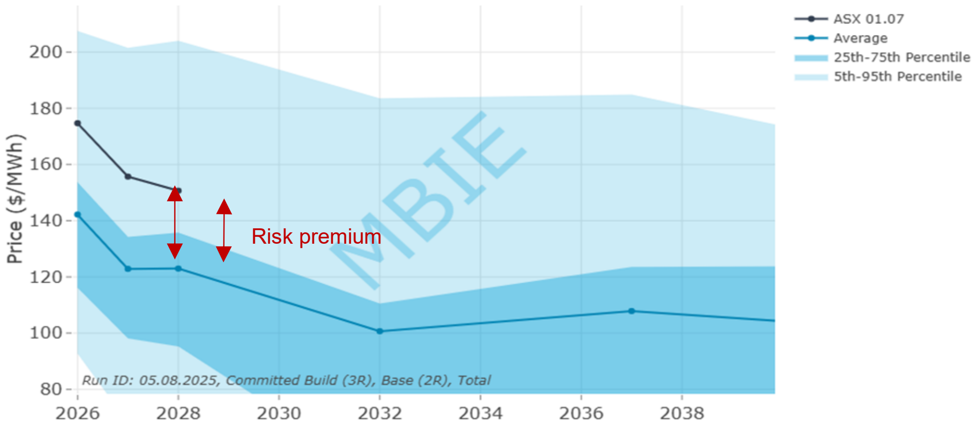
of individual, profit-maximising firms to make significant investments that would only pay off over a series of unpredictable dry years.

18. Wholesale electricity spot prices have more than doubled since 2017, peaking at $893.91/MWh in August 2024. The price of electricity contracts remains elevated, averaging above $150/MWh since 2022.

19. Australian Securities Exchange (ASX) futures contracts (which are a key determinant of retail prices) have been well above the cost of building new generation since 2018 when gas supply issues first emerged, and have remained elevated despite the pipeline of renewable generation being delivered. In other words, prices should be softening but are not. A significant dry-year risk premium is being baked into forward prices.

20. The dry-year risk premium is estimated by calculating what future spot prices would be across a range of weather conditions, and the difference between this and the actual prices of futures contracts entered into in the last three to four years. This difference, which is consistently between $30 and $50/MWh,[7] indicates that the market appears to remain averse to the risks of shortage (whether from weather-related issues, gas shortages or delayed investment in new generation).

Figure 1 – ASX contract prices include a risk premium



Source: Concept Consulting modelling for MBIE

21. Current market activity is not delivering the level of investment in new cover required to complement renewable generation for long durations. Some actions have been undertaken at the margins, but none (even combined) will provide the level of dry-year cover needed to reduce the risk premium:

- Meridian and New Zealand Aluminium Smelter (NZAS) have reached a deal to provide the ability to call for consumption by the Tiwai plant to be reduced.

- Genesis has agreed with the other gentailers to maintain a unit at Huntly Power Station as a strategic energy reserve for up to ten years at (the Huntly Heads of Agreement). The deal maintains a unit currently operational so it does not add new generation capacity.

- Genesis and Channel are both investigating additional plant investments, however, these are at early stages and dependent on obtaining long term supporting contracts.

[7] Modelling commissioned from Concept Consulting. In addition a recent report from Boston Consulting Group also identifies a $30/MWh dry-year risk premium [Energy to Grow: Securing New Zealand's Future]

Estimating the scale of cover that might be needed

22. It is difficult to estimate the precise scale of the dry-year problem. A number of different attempts have been used to quantify the size of the gap. In particular:

- Confidentiality the dry year problem can reach about 4 TWh in a worst-case scenario (worst 24-month deficit accompanied by low wind generation). This worst-case scenario assumes two consecutive dry sequences.[8]
- The experience of 2024 (which, as noted above, was not the worst dry year on record from a purely meteorological perspective) was that there was approximately a 1.7 TWh shortfall in hydro generation that needed to be made up.
- MBIE has assessed residual supply requirements over a 20-year period, that is supply that would be needed above renewables to meet demand, indicates approximately:[9]
    - 2.5 TWh of additional supply needed over a 90-day period,
    - 1 TWh needed over a 30-day period, and
    - 6 TWh needed over a 365-day period.
- The NZ Battery Project estimated the size of the gap to be 3-5 TWh over the course of a year based on historical data. The Frontier report adopts this estimate in its analysis of the dry-year problem.
- Previous analysis by the Gas Industry Company suggested a dry year shortfall of approximately 3.2 TWh of energy.[10]
- Analysis by Concept indicates that up to approximately 2.6 TWh of thermal generation could be needed in 2028 and approximately 2.3 TWh in 2035 over a 3-month period.

23. These suggest that a reasonable estimate of the problem's scale under most plausible weather and demand conditions is:

    - 2.5-2.7 TWh over three months; and
    - 3-6 TWh over a year.
    - Other risks and uncertainties can impact this further, such as:
        - reliability of ageing thermal plant,
        - delayed build of renewables (a one-year delay has a significant impact, and is consistent with trend), and/or
        - greater gas supply decline (there are known downside risks on current forecasts).

24. Taking into consideration the Huntly Heads of Agreement could provide up to 1.5 TWh over three months, the above analysis suggests appropriate additional firm generation cover of up to 1.5 TWh over three months.

[8] Confidentiality

[9] MBIE analysis of EA generation data.

The Government announced an Energy Package in response to the Review, including investment in energy security

25. In response to the Frontier report, the Government (CBC-25-MIN-0054) accepted Frontier's key conclusion that the electricity market alone will not deliver the firming capacity required and agreed two workstreams aimed at investing in energy security (Workstream One) and building better markets (Workstream Two). The key actions relevant to this case are:

- Commence phase one of a procurement process for an LNG import facility to provide reliable dry-year fuel supply (Action 1.1). The Minister for Energy was invited to report back about this in December 2025.
- Establish a regulatory framework to ensure the market has the right incentives to deliver firming capacity (Action 2.5). This is aimed at addressing the problem in the longer-term. Decisions regarding this framework are expected in early 2026, however, given investment lead times, is likely to come into full effect from mid-2030s. This timing aligns with expected retirement of key thermal plant.

26. The rationale for *Action 1.1 Investment in an LNG import facility* is that it is likely to support wider delivery of the Energy Package and other energy system initiatives by providing a high degree of certainty on supply of natural gas, albeit at higher prices than pre-2022. This will enable investment decisions, and support demand (i.e. reduce firm closure) until new fuel/energy sources become available.

Problem definition

Risks facing New Zealand's electricity system

27. New Zealand's electricity system is relatively rare globally in that it is a hydro-dominated system with no interconnectivity with other jurisdictions. In 2023, hydro generation comprised 60 per cent of all electricity generation in New Zealand. We also have relatively low storage capacity in our hydro lakes (equivalent to about 6 weeks of total electricity demand). New Zealand therefore requires regular rainfall to fill our hydro lakes and support hydro generation. Periods without rain leave New Zealand susceptible to the dry-year problem.

28. Dry periods are dependent on weather patterns, and each is different. It is impossible to predict the magnitude, length, or specific timing of dry years. We can, however, expect that they will occur once every three to five years.

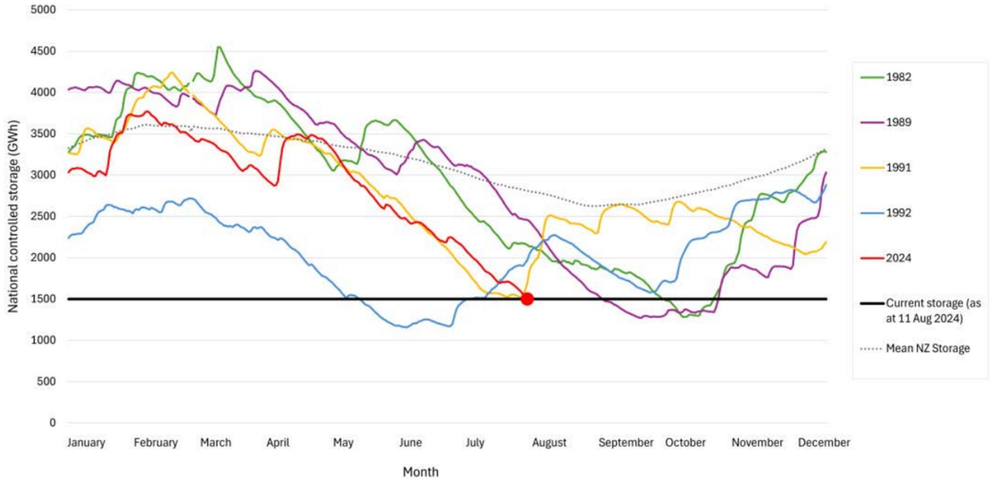
29. The system also includes risks beyond those caused by weather. Our largest load centres are located a long way from our major hydro generation sources in the South Island, meaning our transmission system is a significant vulnerability.

30. Additionally, our existing thermal generation is ageing (including some that is due for retirement) and prone to outage. Some of New Zealand's thermal generation plant experienced significant sustained outages in 2023 and 2024.

31. The below graph provides a comparison of hydro storage in selected dry years compared with an average year. It illustrates two key points about dry years:

- Dry years can be significantly 'dryer' than mean years, with hydro storage in dry years being under half of what is observed in average years.
- The timing profile of dry years (i.e., when lake levels start reducing below mean and when they begin to recover) can vary significantly among dry years, although they tend to reach their lowest point in or just after winter.

Figure 2: Controlled hydro storage levels during past dry years



Source: Transpower – Weekly Market Movements – 11 August 2024

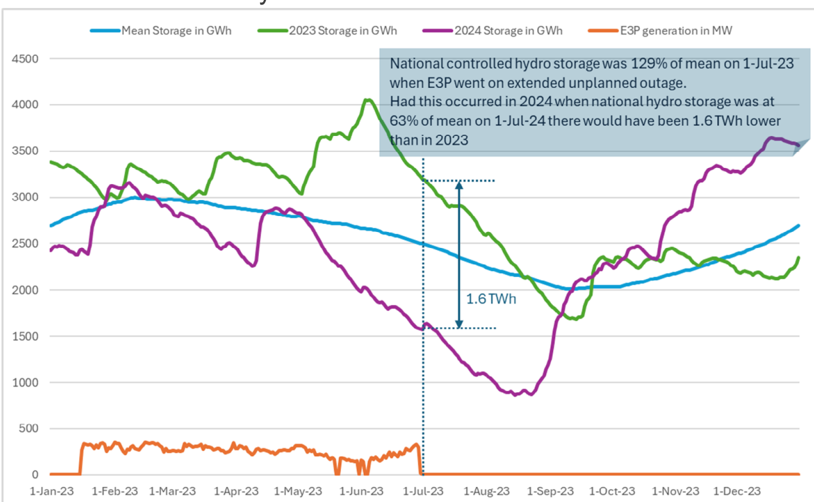
32. The presenting constraint for electricity generation is the availability of fuel. In previous dry years we have relied on gas to provide the firming capacity needed, but the rapid drop-off in domestic gas supply makes that solution increasingly unreliable. Part of what made 2024 such a bad "dry year" was the fact that the weather conditions coincided with an acute shortage of domestic gas, meaning that:

- gas-fired generation only ran at 65% of capacity, and
- a deal had to be reached with Methanex to use its gas (an option that was expensive, and which may not be available in future years).

Box 1: Lessons learnt from 2023 and 2024

Recent experience has highlighted some of the potential risks in our system.

In 2023, we had reduced dry year firming generation with an extended unplanned outage of two gas turbines[11]. Fortunately, we had comparatively healthy hydro inflows that year meaning we did not need to rely on dry-year generation. Had this been a dry year, the situation would have been very different.



In 2024, hydro inflows were low (but not the lowest), heading into winter we also had below average wind and some new generation expected to be fully available was delayed. This increased the need for dry-year cover generation. Coal stockpiles were rapidly drawn down

[11] The E3P Combined Cycle Gas Turbine, and an outage of an Open Cycle Gas Turbine

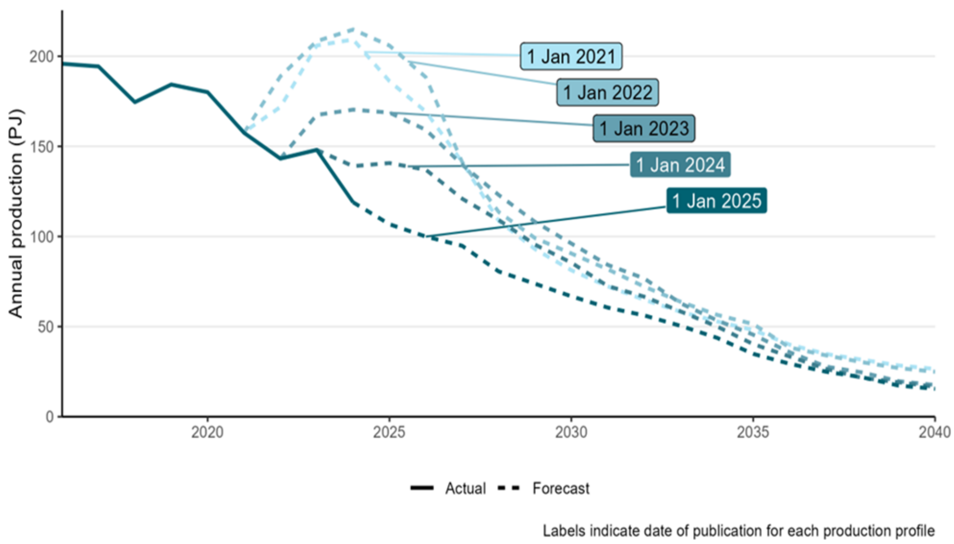
and unable to be quickly replenished. Combined with reduced gas supply from our domestic fields, thermal backup generation was limited. Meridian triggered its demand response contract with NZAS, and generators purchased gas off Methanex. Spot prices exceeded $800/MWh, reflecting how tight the market got during this time. Some other industrial electricity users stopped operation during this time and some made the decision to permanently exit (reflecting a combination of challenges those firms were facing).

Meanwhile domestic gas supply is rapidly declining

33. Natural gas is a key energy source in New Zealand, and in previous dry years has provided dry year electricity generation cover. Besides electricity generators, gas users include 300 large industrial businesses, 16,000 commercial businesses, and 290,000 households.

34. Gas production has been falling rapidly since 2018. Gas reserves have been consistently revised downwards despite $2 billion of investment over the last 6 years in drilling wells. Forecast 2025 gas supply is 48% lower than what the sector forecast it would be in 2022.

Figure 3: Gas Production Forecasts



Source: Energy in New Zealand 2025, MBIE

35. Natural gas prices, which both set the marginal price of electricity and are a critical input for industry, have significantly increased since 2018. A number of firms report their gas prices have tripled from $7-8/GJ in 2018 to $25-$35/GJ in 2025.

36. Demand from electricity generation affects our gas-intensive industries such as metals and paper manufacturing. These have been hit hardest due to their higher gas use and (in some cases) limited alternatives. Several major firms, including wood manufacturer Oji and Ballance agri-nutrients, have already closed or announced plans to curtail production if they cannot secure gas contracts.

37. Other firms have indicated that power prices may lead them to significantly scale back their production or close up entirely.

38. Given the broader social and economic impacts of declining domestic gas supply (both in of itself, and as it affects electricity prices), the impact on the gas market of any option considered in the economic case below is included as a spillover benefit. The Government also has other work underway more directly targeted at issues facing gas

suppliers and users, such as the gas co-investment fund and Government Statement on Biogas.

The counterfactual – what will happen without intervention

39. Before setting out the case for government investment and the potential scale that any investment would need in order to be effective, a broad sense of how the market is likely to develop without intervention is useful.

40. Over the medium to long term, we expect to see further renewable generation be developed. The Electricity Authority's generation pipeline as of 21 November 2025 includes 288 generation projects (mostly solar and wind) with a combined total capacity of 44.32 GW. The pipeline supports the Frontier finding that the market is delivering renewable investment, although it is highly unlikely the entire pipeline will be delivered. For instance, 41 of the projects in the pipeline (3.75 GW) have been committed or are being actively pursued.[12]

41. If renewable build outpaces demand growth and gas decline, and other risks do not materialise, then the balance between electricity supply and demand could improve in the coming years to decade, putting downward pressure on prices. Estimates by various commentators suggest 95-98% renewable generation could be achievable.

42. However, given the majority of new projects will be weather dependent (mostly wind and solar), New Zealand will remain exposed to weather-related risks to electricity supply. Given the revenue uncertainty associated with firm generation and other risks identified in the Frontier report, market participants are not expected to invest in cover that would provide an appropriate level of cover for the dry-year problem i.e. individual firms will invest in some cover, but not up to the level desirable for New Zealand as a whole.

43. As a result, the risk premium factored into forward contract prices will remain. This means that even in an average hydrological year, where spot prices might not be elevated, electricity costs will remain high ($30-50/MWh above what they would otherwise be).

44. Meanwhile, the ongoing reduction in gas supply and knock-on effects in gas markets, will change the role gas can play in fuelling dry-year generation. In this regard we face three distinct time periods, each with different uncertainties and features.

Time period 1: Commercial Information

45. In this period, we will continue to face an undersupply of gas in the economy. The electricity system is susceptible to adverse weather, pushing up the need for gas for electricity generation to fill the gap. Commercial Information gentailers will likely pay Methanex to shut down and provide its gas if needed to get through a dry year. Demand response from Tiwai may also be needed. The high cost of this demand response (and the risk of needing to pay this high price) will be reflected in high forward prices.

Time period 2: Commercial Information

46. Commercial Information

[12] "Actively pursued" means the project has submitted a consent application, secured a location, or executed finance contracts.

Time period 3: Long term domestic gas shortfall addressed by LNG, increased share of renewables, however retiring thermal plant creates a different dry-year cover problem

47. Domestic gas supplies have declined such that there is a shortfall for electricity generation and direct users. It is possible additional gas storage will be available, however, this is uncertain. LNG is expected to be required somewhere from mid-late 2030s (and is built into most market models).

48. The problem will likely evolve: the dry-year/weather related problem is expected to reduce as a result of the scale of renewable build and availability of LNG, but new issues emerge as ageing thermal generation kit is retired. There is now less incentive to invest, given the reduced need, on average, for thermal generation and therefore greater revenue uncertainty.

The role for Government in addressing the dry year problem

49. In theory, sustained high prices should create investment incentives. In practice, however, additional investment to provide dry-year cover has not been forthcoming despite elevated forward prices and significant investigations by the sector into options. There is more generation capacity in the pipeline, but it is not new reliable, easily dispatched, generation capacity that would meet dry-year demand.

50. Dry year cover is only needed sporadically, and so it can be thought of as akin to an insurance product. In the absence of the market providing that insurance product, and in view of the benefits it would deliver (secure and more affordable electricity), there is a role for Government to purchase cover on behalf of all market participants and recover capacity costs through a broad-based levy. As with other insurance products, by purchasing dry-year cover, users will incur a cost during normal years in exchange for assurance that in dry years there will be security of supply. This stability is in turn expected to lead to lower spot prices in dry years, and lower forward prices.

Investment objectives and scope

51. The following are the minimum criteria for investment options in this business case. A long list of options was developed, and those that meet these criteria have been included in the analysis under the economic case. A long list of other options that did not meet these criteria is set out in Annex One.

Scale of cover: 1.5 TWh over 3 months

52. The Government's investment objective is to deliver, at as low a cost as possible, a solution that provides firming cover of up to 1.5 TWh. This is in line with the estimates of appropriate cover for a dry year, adjusted for the Huntly agreement (i.e. that part of the dry year cover the market will deliver). In combination, this is likely to provide cover in most dry winters (including an event like 2024). In the most extreme dry-year events there could be a further 2 TWh required over the course of a year that would need to be made up. However, these are rare, and the cost of purchase for that level of cover is unlikely to meet a cost-benefit test.

Delivery of cover by 2030

53. As with the scale of cover, there is no 'right' timeframe that the cover needs to be in place by, we do not know when the next dry-year will occur. Given the likely benefits on forward prices that certainty of cover will provide, the introduction of cover as early as possible would be beneficial, subject to the cost and implications for the broader electricity and gas markets being acceptable.

54. Considering the rapid decline in expected domestic gas production and the potential for a highly uncertain gas market Commercial Information we recommend delivery by 2030.

55. Requirements beyond 2030 are increasingly uncertain about factors such as technology, energy transition outcomes, and fuel availability. They are also closer to the implementation of measures that are likely to emerge from the dry-year regulatory work programme (Action 2.5 of the Energy Package). This means that there is increasingly less value and greater risk with any particular investment solution. The trade-off between timeliness and other considerations is discussed further in the economic case.

Proven technologies

56. While the requirements for any solution are technology-neutral, they do need to be reliable and proven, so that they will be available when required at a predictable cost. Future or emerging innovations in generation and storage can be considered by the market at the point of plant retirement in the mid-2030s, supported by the dry year regulatory framework.

Economic Case

Key points

- **The economic case assesses and contrasts five potential options that could provide up to 1.5 TWh of additional dry-year cover (summarised in Table 1). This analysis illustrates that an LNG import facility is a strong option for Government investment in dry year cover across assessment criteria.**
- **An LNG import facility is expected to put downward pressure on electricity prices: LNG has a marginal cost of generation between $200–$250/MWh using existing plant, less than diesel. This lower cost of generation will have a greater effect on reducing forward prices, as well as spot prices.**
- **Capital costs for an LNG import facility are expected to be relatively low at** Commercial Information **whole of life cost, and if spread across all generation would add $2.05-$4.10/MWh to the price of electricity. This should be more than offset by the reduction in risk premium. Modelling shows that having LNG available in 2028 would result in average spot prices being $58/MWh lower in a dry year and $11/MWh lower in an average year.**
- **No further investment is required, as LNG will fuel existing plant. This also means it does not lock in new thermal generation and is thus less likely to impact incentives to invest in renewable energy (or crowd-out other investment in generation plant).**
- **Importing LNG delivers significant economic spillover benefits - LNG could provide gas supply for other users, particularly less price-sensitive industrial, commercial, and residential users.**
- **Under an accelerated delivery scenario, a terminal could be operational in 2027 making this the fastest option.**

Table 1: Summary of Options analysis scores (1=best, 5=poorest)

Criteria	**Import LNG** ranges indicate variations for faster delivery	**Rankines**	**Peakers**	**Low-capex Portfolio**	**Additional Cover: LNG+TCC**
Timeliness	1-2	5	2	2	2
Capital cost (insurance premium)	2-3	5	1	2	3
Generation cost / affect on prices	2	1	5	2	2
Flexibility	2	5	4	4	4
Spillover costs	3	5	4	4	4
Spillover benefits	2	2	3	2.5	2

Purpose of this economic case

57. The purpose of the economic case is to identify and contrast potential options available to provide the additional 1.5 TWh low-cost cover considered appropriate for most dry periods. Non-LNG options have been presented for the purpose of assessing the merits of investing in import of LNG and have not been developed in detail. If ministers were interested in pursuing them, further work would be needed before decisions could be taken about them. For example, it is possible that the Dry Year Regulatory Framework could result in the market delivering some of the alternative options (albeit in a longer timeframe).

Approach

58. The strategic case sets out the minimum features required of any investment. We have identified a short-list of potential options that could also deliver on those. Annex One sets out other investments that did not make the short-list and the rationale for exclusion.

Overview of options

59. Table 2 below describes each option, including two 'portfolio options' that combine multiple options. All options have been designed and sized to be capable of providing up to 1.5 TWh of energy over a three-month period.

Table 2: Overview of options

Option	Description
1. LNG import facility	Subject of current procurement process, and therefore the illustrative model informing this business case is: an LNG import facility that includes a floating storage and regasification unit (ship) semi-permanently moored in Port Taranaki, delivering a minimum of 12PJ over 3 months.[13] Assuming 80% availability of all gas-fired units across three consecutive 3 months, this would deliver ~1.5TWh.
2. Illustrative Rankine option	New Rankine cycle steam plant and supporting infrastructure (e.g. cooling towers). This consists of 3 x 250MW units, coal or biomass fired, which could produce 1.3TWh over 3 months (assumes location with good transmission capacity available, and readily consentable).
3. Illustrative Peaker option	New 300MW open gas cycle turbines (OCGT) capacity at Marsden (assumed in smaller increments) Conversion of existing gas-fired OCGT peakers in Taranaki to run on diesel (400MW).
4. Low capex portfolio option	New coal/biomass fired 250MW Rankine at Huntly. Conversion of two existing gas-fired OCGT peakers in Taranaki to run on diesel (200MW). New 150MW OCGT at Marsden. Remaining shortfall to be covered by demand response.
5. Additional cover: LNG and Taranaki Combined Cycle (TCC)	Conventional LNG import facility as above, fuelling existing gas-fired kit plus a refurbished Taranaki Combined Cycle. In total, producing approximately 2.3 TWh over 3 months requiring ~19PJ of gas for generation.

[13] Based on investigations by UK Gas Strategies, commissioned by NZ industry consortium, 2024.

Criteria

The following table sets out the criteria the options have been tested against. No single criteria dominates, and some are intrinsically linked. For example, the cost of the proposal (and therefore the levy), will offset the price effect.

Table 3: Criteria for options analysis

Criteria	What it is and how assessed
Cost of proposal	*The capital costs to deliver and electricity generation costs of the investment* This includes an indication of the likely size of any cost recovery levy (insurance premium), absent commercial revenue.
Effect on electricity prices in relation to costs of generation	*The likely price benefits of the investment* The impact on electricity spot prices in both average (P50) and extreme (P95) scenarios, which flows through to forward contract prices in varying ways under different scenarios. Preferred options are those which are more likely to put greater downward pressure on forward contract prices and therefore on any inherent 'risk premium'.
Flexibility	*The extent to which the insurance/investment enables the system to respond given a range of uncertainties.* Elements of flexibility include: • Is able to deal with different levels of demand – e.g. if the dry year gap is ultimately smaller or larger than anticipated. • Is able to switch between different fuels and sources providing additional resilience. • Maintains option value – leaves incentives in the market for replacement/alternative investment.
Timeliness	*The pace at which the insurance/investment can be delivered.* As set out in the scope section of the strategic case, the options being considered aim to improve dry-year cover by Winter 2029. Options that can deliver cover earlier than that are preferred.
Spillover costs and benefits	*Costs and benefits beyond electricity security and affordability.* May include: • Broader economic impacts. • Impact on emissions. • Impact on the gas market and gas users. • Potential impact on future (renewable) generation pipeline.

Options

Option 1. LNG import facility

60. The LNG option presented below is based on previous (2024) assessment work on the feasibility of establishing an LNG import facility in New Zealand conducted by UK Gas Strategies and commissioned by a consortium of New Zealand energy sector participants. The facts and figures presented are indicative in nature and do not necessarily represent the final shape and form of an LNG importation facility. They do however provide a reasonable basis for comparison.

61. A Registration of Interest, and invitation to provide an accelerated delivery solution for an LNG import facility closed on 17 November 2025.

62. Analysis of proposals is currently underway, this or a future Request for Proposal procurement process may result in a solution that differs in detail from the option described below. The option analysed below is at the higher-cost end of options submitted through the Registration of Interest process. A conservative approach is appropriate given the early stage of proposal development (further design work is likely to identify additional costs).

Description

63. Involves the establishment of an LNG import facility that includes a 4PJ floating storage and regasification unit (ship), semi-permanently moored in Port Taranaki. It assumes that the imported LNG will be used in existing gas-fired generation units. Assuming 80% availability[14] of all gas-fired units across three consecutive 3 months, it is estimated that ~1.5TWh could be generated with ~13PJ of gas.

Financial Costs

64. The capital costs associated with the establishment of an LNG import facility and the associated insurance premium and electricity generation costs are set out in the table below.

	Cost	Assumptions/explanation
Capital cost of investment	Commercial Information [redacted]	Capex includes expenditure on LNG terminal and associated port upgrades and other ancillary costs.
Whole of life cost	Commercial Information [redacted]	Includes the capital cost, and operation and maintenance costs of the project.
Insurance premium	$3.80/MWh[16]	Calculated as annual charter fee divided by total production.
Electricity generation cost	$200-$250/MWh	Generation cost assumes the price to the generator of LNG is $20-$25/GJ. It includes the LNG supply costs, ETS and storage and transmission costs (full cost breakdown provided in the section on *Additional analysis on LNG import option)*.

Effect on electricity prices in relation to generation costs

65. Market dynamics, particularly in the period 2028 to 2035, are uncertain given material uncertainty about the domestic gas supply and changes in demand. The commentary here (and in the discussion of other options that follows below) is based on assumptions and judgements, supported by analysis of the LNG option under a range of scenarios.

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14 Capacity considerations have been built into all options. Thermal generation plant will not generally run at full capacity due to operational and maintenance (O&M) requirements, and/or unplanned outages. These O&M requirements can be varied in case of need, but it is not desirable to plan a system for 100%.

[redacted] Commercial Information [redacted]

16 The potential range, based on ROI submissions is $2.05 - $4.10/MWh

66. The potential impact of this option on average spot electricity prices and forward electricity prices are presented in the table below.

<table>
<tr><th></th><th>Commentary</th><th>Price reductions, relative to other options
(listed strongest to least effect)</th></tr>
<tr><td>Potential impact on average spot electricity prices</td><td>Modelling indicates a material reduction in extreme spot prices can be expected from adding an LNG facility. These effects are even more pronounced if the system loses one of the three Rankine units. More detail on LNG modelling outcomes under a range of scenarios, and in the near term (2028) and longer-term (2035) can be found in the Additional analysis on LNG import option section below.</td><td rowspan="2">Rankine-based option (2)

Mid range: LNG import (1), Low Capex portfolio(4) and Additional Cover portfolio (5)

Peaker-based option (3)</td></tr>
<tr><td>Potential impact on average forward contract prices</td><td>Material reduction in extreme spot prices can be expected to reduce the apparent risk premium, resulting in downward pressure on forward prices.</td></tr>
</table>

67. BCG modelling suggests that the risk premium could be reduced by around $10 if an LNG import facility were available – a benefit of $400 million per annum for electricity consumers. Combined with the estimated insurance premium above, the net reduction in forward prices could be in the order of $6.20/MWh or $250 million per annum[17]. Given MBIE estimates the risk premium to be $30-50/MWh, we consider a $10/MWh reduction to be conservative i.e. a lower bound.

Timeliness

68. Proposals submitted through the ROI could deliver as early as 2027, otherwise an import facility is expected to be delivered by 2029. The difference in timing is linked to whether ships are already available, or need to be built for the project; and the extent of port upgrades. It is also affected by duration of the procurement process.

Flexibility

69. Fuel will likely be purchased on the spot market which means that there are many supply sources (though gas does need to fit with New Zealand specifications), and that deliveries are flexible on timing, particularly in light of expanding production globally (though this can entail a price premium).

70. A conventional scale option would involve the charter of a floating storage regasification unit with a storage capacity of 4PJ (sufficient to provide 30 days cover to run our existing (gas) generation kit during a dry year). This provides considerable flexibility to call on LNG from the spot market if and when needed.

71. There are options to "sub-let" the vessel if it is not required or not renew the charter at the term of the contract.

[17] Based on submissions: net reduction in prices could in the range of $7.95-$5.90/MWh; generating savings for consumers of $220-$310 million per annum.

Spillover costs and benefits

Emissions

72. A Climate Impact of Policy Assessment (CIPA) has been completed for LNG. This includes modelling of the electricity sector with and without LNG. The fuel stack for energy generation shows less emissions in a scenario with LNG than without. There are several factors at play:

- diesel and coal (the alternative thermal fuels) are more emissions intensive than gas-fired generation, and are used more in a no-LNG scenario, and
- the certainty that there is back up available, if required, results in less conservative use of hydro-generation. That is hydro generators don't need to "hold back" water in case they need it later in the dry period, as they know an alternative will be available.

Broader economic impacts

73. LNG could provide additional gas supply for some direct users, including less price sensitive industrials, commercial and residential supply.

74. MBIE has worked with industrial gas users, who have confirmed that there is a significant variation in the tolerance for increases in gas prices from firm-to-firm, and over time. Based on feedback Commercial Information [redacted] In the recent Business Energy Council (BEC)/Optima survey, most businesses surveyed (80%) have contracts expiring by 2027, creating a narrow window for necessary transitions to alternative fuel sources.

75. Some industrial users may need to continue to use gas in future. This is especially important for firms that are reliant on high temperature or gas-specific processes (e.g. chemical, metal fabricators). For other firms, LNG may be affordable short-term while they transition to alternative energy forms.

76. LNG would set a gas ceiling price of $20-25/GJ. That is, domestic wholesale gas prices (currently rising rapidly given the decline of domestic gas supply) would not pass the LNG price.

77. Given the shortfall in domestic supply, import of LNG may also see domestic gas rise more quickly to (just below) the LNG price of $25/GJ than it otherwise would have. However, if gas supply continues to decline, domestic gas prices will almost certainly reach $25/GJ, and possibly more. Further analysis on the options for mitigating upward price pressures are provided in section on *Additional analysis of LNG import option.*

Option 2. Illustrative Rankine option

Description

78. This option involves the purchase and establishment of a new coal/biomass-fired Rankine cycle steam plant and supporting infrastructure (e.g. cooling towers).

79. To generate 1.23TWh over three months would require three 250MW Rankines.[18]

80. It is unlikely that three additional units can be sited at Huntly and this option therefore involves the establishment of a new power station. To reduce costs, building timeframes and avoid regulatory barriers, it would be desirable to locate such a facility on a site where existing infrastructure could be leveraged i.e. a brownfield site.

Financial Costs

81. The capital costs associated with the establishment of a new Rankine-based power plant and the associated insurance premium and electricity generation costs are set out in the table below. This is the most capital-intensive option but offers the lowest cost of generation.

	Cost	Assumptions/explanation
Capital cost of investment	$4.5 - $5.1 billion	The cost to build a coal-fired power plant varies significantly depending on technology, location, and environmental regulations. Limited New Zealand-specific data is publicly available, we have therefore used international benchmarks for a proximate estimate for construction of a 750MW thermal power plant.[19]
Whole of life cost	$14.3 billion	Assumes a midpoint capital cost of about $4.8 billion and 40-year lifetime of asset.
Insurance premium	$8.20/MWh	The insurance premium/levy is based on the whole of life cost of a new power plant.
Electricity generation cost	$150-170/MWh (coal) $184-215/MWh (biomass)[20].	The cost of generation depends on fuel source used.

[18] Using the existing Rankine units at Huntly as a benchmark, a 250 MW Rankine with a plant factor of 75% could result in 187.5 MW of generation capacity on average. This would result in 1,642.5 GWh (1.64TWh) annually, or 410.6 GWh over a three-month period. Based on this calculation, three 250 MW Rankines, which could generate 1.23TWh over a three-month period, would be required to approximate the desired dry-year cover. Rankine units can be run at higher capacity for short periods, if required.

[19] Based on U.S. Energy Information Administration (EIA) data, capital cost for a conventional coal power plant is approximately US$3,500 to $4,000/kW, or US$3.5 to $4 million/MW.

[20] These figures are based on MBIE modelling which used public figures from Foresta (lower end estimate) and figures provided by NZTE from Japan (higher end estimate).

Effect on electricity prices in relation to generation costs

82. The potential impact of this option on average spot electricity prices and forward electricity prices are presented in the table below.

	Commentary	Price reductions, relative to other options (listed strongest to least effect)
Potential impact on average spot electricity prices	As this option adds capacity and fuel diversity, it is likely to provide a reasonable cap on extreme spot prices. This is likely to be more so than the LNG option due to lower coal prices (relative to LNG) and the benefit of additional capacity.	**Rankine-based option (2)** Mid range: LNG import(1), Low Capex portfolio (4) and Additional Cover portfolio (5) Peaker-based option (3)
Potential impact on average forward contract prices	A material reduction in extreme spot prices can be expected to reduce the apparent risk premium, resulting in downward pressure on forward prices.	

83. Due to the low cost of generation, this option is likely to have the greatest benefit in terms of downward price pressure. However, with a high capital cost, and therefore the highest insurance premium, the net effect on forward prices is less clear.

Timeliness

84. The IEA estimates a new plant to take 4 to 6 years to become operational[21]. This means that the delivery date could be anywhere between 2030 - 2033.

Flexibility

85. This option is flexible in terms of the fuel types that can be used – the multi-fuel generation proposed is equally capable of running on coal, gas, biomass and may be run on other substances (depending on the specific plant). This provides stronger resilience, compared to other options. When prices for certain fuel sources are high, or the resource is scarce, other fuel can be used. It also provides some optionality in managing geo-political impacts on fuel sources (price and/or supply).

86. The option is flexible in terms of dealing with different levels of demand - the size of the stockpile (coal and/or biomass) can be adjusted in accordance with demand.

87. The plant has an estimated life of 40-50 years, which does risk some lock-in effect and/or crowding out of other investment. However, should the market develop more efficient means of covering the dry year problem (changes in technology, changes in use of hydro, for example), then it is possible to on-sell these units.[22]

[21] https://www.iea.org/data-and-statistics/charts/average-power-generation-construction-time-capacity-weighted-2010-2018

[22] There is limited public information available on the resale value of generation units. Specialised equipment brokers are the primary sources for used Rankine cycle power units and prices would depend on the age and conditions units will be in.

Spillover costs and benefits

Emissions

88. Burning coal has significantly higher carbon dioxide (CO_2) emissions than equivalent gas generation (according to Energy Information Administration data, coal produces 1,000-1,050 grams of CO_2/kWh vs 410-435 grams of CO_2/kWh for natural gas). [23]

89. Biomass fuels are a low emissions fuel as the carbon they release has been pulled from the atmosphere.

Broader economic impacts

90. There may be positive economic impacts associated with the use of biomass as a fuel source. Increased demand for biomass as a fuel source could have a positive impact on the further development of the biomass/biofuel industry. As highlighted in the Wood Energy Strategy: "…increased wood energy production in New Zealand could provide a new line of processed products, diversifying and relying less on exports of low-grade unprocessed logs for regional income, increasing regional economic productivity and resilience. It could create new skilled jobs for experienced workers and attract new skilled workers to the affected regions".[24]

Impacts on the gas market and users

91. There are likely to be some benefits to gas users, if the electricity sector is less reliant on gas for firming. The extent of this effect will depend on relative fuel prices and status of contracts. It will not, however, offer the same potential for additional gas as LNG imports.

Option 3. Illustrative Peaker option

Description

92. This option would involve:

- building new diesel-fired 300MW open-cycle gas turbines (OCGT) at Marsden Point/Bream Bay, and
- the conversion of the four gas-fired OCGTs in Taranaki to run on diesel:
    - Stratford (2x 100MW), Junction Road (100MW), and McKee (100MW).

93. The combined size of the new and converted units would be 700MW. Assuming a plant factor of 80%, this would result in 1.23TWh of generation over three months (80% reflects operational requirements, but can be extended in case of need).

94. Transpower's latest transmission planning report indicates ~350MW of additional generation should be possible at nearby Bream Bay. Transmission upgrades might be needed if a new peaker is installed at Marsden as current capacity may be limited to 80 MW.

95. Marsden Point has facilities to store more than 290 million litres of fuel which would provide diesel to power the peaker, avoiding the need for additional storage costs.

96. The four gas-fired OCGTs in Taranaki can be modified to run on diesel (they would become dual-fuel capable) and existing condensate/methanol pipelines can be used/re-purposed to transport diesel from Port Taranaki to these units. This pipe could be fed by the installation of diesel storage tanks (48 million litres) at the port.

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[23] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11

[24] Wood Energy Strategy - https://www.mbie.govt.nz/assets/wood-energy-strategy.pdf

Financial Costs

97. The capital costs of this option and the associated insurance premium and electricity generation costs are set out in the table below.

	Cost	Assumptions/explanation
Capital cost of investment	$0.66 billion	Capital cost of a new 300MW OCGT is estimated to be $0.53 billion based on: • Cost of Whirinaki $0.15 billion in 2003. • Inflation adjusted, this equates to $0.26 billion in 2025. • Extrapolated to account for the 300MW size of the proposed solution (2x size of Whirinaki). Conversion of the Taranaki peakers to run on diesel is estimated to cost approximately $0.07 billion.[25] We have little information on the costs associated with the conversion of existing condensate/methanol pipes to diesel. We understand it is technically feasible although additional pumping infrastructure will be required to manage pressure. We have provisionally assumed $0.02 billion and this figure has been included in the $0.07 billion conversion cost estimate. The capital cost associated with the installation of four additional 12 million litre tanks at Port Taranaki is estimated to be $0.06 billion.[26]
Whole of life cost	$1.8 billion	
Insurance premium	$1.20/MWh	The insurance premium/levy is based on the whole of life cost of new peaker and conversion of existing peakers and associated infrastructure.
Electricity generation cost	$510-$570/MWh	Based on Electricity Authority estimates[27]

[25] Inflation adjusted figures from the following source:
https://www.engineeringnews.co.za/article/eskom-moves-ahead-with-dual-fuel-conversion-of-ocgt-plants-despite-gas-uncertainty-2016-01-21 https://www.engineeringnews.co.za/article/eskom-moves-ahead-with-dual-fuel-conversion-of-ocgt-plants-despite-gas-uncertainty-2016-01-

[26] Figures obtained from MBIE commissioned Fuel Security Study: https://www.mbie.govt.nz/assets/fuel-security-study.pdf

[27] https://www.ea.govt.nz/documents/7159/Review_of_winter_2024_jnOSQfc.pdf

Effect on electricity prices in relation to generation costs

98. The potential impact of this option on average spot electricity prices and forward electricity prices are presented in the table below.

	Commentary	Price reductions, relative to other options (listed strongest to least effect)
Potential impact on average spot electricity prices	As it adds capacity and fuel diversity, it is likely to provide a capping effect on spot prices. But because diesel is a much higher cost fuel, the capping effect would be at much higher spot prices than either an LNG option or a Rankine-based option.	Rankine-based option (2) Mid range: LNG import(1), Low Capex portfolio (4) and Additional Cover portfolio (5) **Peaker-based option (3)**
Potential impact on average forward contract prices	As only a modest reduction in extreme spot prices is expected, this option would have a materially lower impact on reducing the risk premium in wholesale prices.	

Timeliness

99. In July 2025, Genesis announced it was exploring a new fast-start generation plant at Huntly and that this could be operational from Winter 2027. This timeframe may be achievable at Huntly because a lot of the required infrastructure (and consents) is already available.

100. Given the size and nature of peakers at Bream Bay/Marsden Point, a 2028 operational date is more likely (noting that the building of the unit could be done in 100MW increments, potentially delivering some benefit earlier).

101. The existing Taranaki peakers may be converted/ operational by 2028, though further work is needed to confirm requirements for condensate pipes and storage facilities.

Flexibility

102. This option is flexible in terms of the fuel that can be used which is advantageous from a resilience perspective. Typically, open cycle gas turbines can run on a range of fuels including most commonly available liquid fuels as well as gas/biogas.

103. Diesel peakers are fast-start plants that can reach their full power capacity in minutes. This means that they can quickly respond to demand spikes (when other power sources are unavailable) as well as provide longer-term dry year cover.

104. Diesel is a readily available international commodity which is advantageous from a supply chain point of view. There are some geopolitical risks that may impact on the availability/price of the fuel.

105. New Zealand will have minimum stockholding obligations in place for diesel in 2028, which would help mitigate any short-term shocks.

Spillover costs and benefits

Emissions

106. Diesel generation has significantly higher CO_2 emissions than equivalent gas generation (according to Energy Information Administration data, diesel produces approximately 1,115 grams of CO_2/kWh vs 410–435 grams of CO_2/kWh for natural gas).

Broader economic impact

107. Unlikely, beyond benefits of energy security.

Impact on the gas market

108. There is likely to be limited impact on the domestic gas market, while this gives the electricity market an alternative to gas, it comes in at a much higher price point. Generators will, therefore, seek to deploy gas-fired generation before accessing long duration diesel-fired generation.

Other effects

109. Running the proposed 300MW peaker at full capacity would consume approximately 1.5 million litres of fuel per day and this may have implications for the minimum stock holding obligation of 28 days (from 2028) and amendments to this obligation may therefore be required, particularly given the likely sporadic use of the plant.[28]

Option 4. Low capex portfolio option

Description

110. This option is about the maximisation of existing kit and infrastructure and aims to minimise capital costs. The following are the key components and assumptions:

Generation	Assumptions
Additional 250MW Rankine unit to be installed at Huntly.	Genesis advises that it is possible to install an additional 250 MW Rankine at Huntly in the space/bay previously occupied by a retired unit.
New diesel peakers (150MW) at Marsden Point/Bream Bay.	The parameters around the siting and configuration of the new peakers at Marsden Point/Bream Bay are largely as described under the previous option, but at smaller scale.
The conversion of existing gas-fired peakers at Stratford (2x100MW) to diesel.	These would use the same diesel storage facilities at Port Taranaki and existing condensate pipes (as per option above).
A demand response of approximately 100MW.	Pre-contracted agreement for one or several large industrial firms to temporarily reduce power consumption, if the need arises.

111. The combined output of the Rankine and new and converted units would be 600 MW. Assuming a plant factor of 75% for the Rankine unit and 80% for the OCGTs, this would result in 1.02 TWh of generation over three months. If required, as a last resort, including demand response of 100 MW would result in this option achieving approximately 1.24 TWh of cover over three months.

112. NZAS already has arrangements in place with Meridian Energy and Contact Energy to reduce its electricity consumption in times of need. However, it is unlikely that NZAS can

[28] Channel have asked for Government help on this issue in their 72MW proposal.

provide a further demand response over and above current arrangements and this response will need to sought elsewhere.

Financial Costs

113. The capital costs of this option and the associated insurance premium and electricity generation costs are set out in the table below.

	Cost	Assumptions/explanation
Capital cost of investment	Commercial Information	Commercial Information The cost of new peakers at Marsden/Bream Bay is estimated to be $0.26 billion (assumptions as in option 3). Cost associated with conversion of Stratford peakers and diesel storage tanks is estimated to be around $0.07 billion (about half the cost of option 3 reflecting that 200 MW will be converted rather than 400 MW). Note there are no upfront costs assumed for a demand response contract.
Whole of life cost	Commercial Information	Assumes a mid-point price for the Rankine unit.
Insurance premium	$2/MWh	
Electricity generation cost	Rankine: $150-170/MWh (coal); $184-215/MWh (biomass) Diesel peakers: $510-$570/MWh Demand response: Unknown but higher than diesel.	

Effect on electricity prices in relation to generation costs

114. The potential impact of this option on average spot electricity prices and forward electricity prices are presented in the table below.

<table>
<tr><th></th><th>Commentary</th><th>Price reductions, relative to other options
(listed strongest to least effect)</th></tr>
<tr><td>Potential impact on average spot electricity prices</td><td>As this portfolio option adds two tranches of “reserve capacity”: coal and diesel, the spot price capping effect is expected to be between the Rankine-based option and Peaker-based option.

The capping effect impact on spot prices is expected to be closer to coal (i.e. at a lower price) than to diesel, as diesel would be called on less frequently than coal (i.e. in more extreme years).</td><td rowspan="2">Rankine-based option (2)

Mid range: LNG option (1), Low Capex portfolio (4) and Additional Cover portfolio (5)

Peaker-based option (3)</td></tr>
<tr><td>Potential impact on average forward contract prices</td><td>This impact is expected to be between the Rankine-based and Peaker-based options.</td></tr>
</table>

Timeliness

115. The suite of generation and demand response could be in place as early as 2028 (installing a Rankine at Huntly can be done more rapidly than creating a new site, as noted above).

Flexibility

116. This portfolio approach offers significant flexibility in fuel types. It does however create additional 40 year assets that may either crowd out other (renewable) generation investment or become stranded (though there is a possibility of on-sale).

117. As noted above, diesel is readily available on the international market, but does also come with geopolitical risk.

118. Demand response is a highly flexible option, in that it can (and will) rapidly drop out as technology and capacity develops elsewhere in the market to cover dry year risk.

Spillover costs and benefits

Emissions

119. This option is likely to generate higher emissions than gas. However, demand response, when called on, will reduce emissions (curtailment of production).

Broader economic impacts

120. Relying on demand response will have implications for GDP in the short term. However, as it is planned and paid for, it is unlikely to result in job losses or permanent drops in GDP. There may also be some benefits in development of the biomass market (though on a smaller scale than would be the case for an additional multi-fuel burner plant (Option 3).

Option 5 – Additional cover: LNG and Taranaki Combined Cycle (TCC)

121. The options described above are geared to providing up to 1.5 TWh of dry year cover. The assumption is that any one of options 1-4, in combination with running the three existing Rankines at Huntly on coal, is sufficient to cover most dry year events. However, there is little resilience in the system if a major component fails. To offer an option for this scenario, we have considered a further option that raises generation capacity.

Description

122. Import of LNG and refurbish (rather than retire) the Taranaki Combined Cycle plant (TCC).

123. The LNG component of this approach is the same as for Option 1: an LNG import facility. In short, it:

- involves the establishment of an LNG import facility, and
- assumes that the existing Rankine units run on coal and that the imported LNG will be used in existing gas-fired generation units.

124. In addition, the TCC will be refurbished. This, in combination with existing gas fired generation kit, could produce approximately 2.3 TWh over 3 months requiring ~19PJ of gas for generation. This larger gas requirement would affect either the scale of LNG delivery required, or additional reliance on storage.

Cost/Impact on electricity prices

125. The capital costs of this option and the associated insurance premium and electricity generation costs are set out in the table below. As with option 1 (LNG import facility), a conservative, higher cost option has been assessed.

	Cost	**Assumptions/explanation**
Capital cost of investment	Commercial Information	Capital cost of LNG component as per LNG option. Commercial Information
Whole of life cost (WOLC)	Commercial Information	
Insurance premium	\$4.10 - \$4.50/MWh	
Electricity generation cost	Cost of electricity generation for TCC: \$155-\$195/MWh Cost of electricity generation for existing generation kit: \$200-\$250/MWh	Assumes LNG price of \$20 and \$25. Combined cycle gas turbines are more efficient than OCGT peakers giving lower generation costs.[30] Therefore generation would generally be deployed at TCC and Huntly Unit 5 first, and gas peakers second.

Commercial Information

30 It is estimated TCC has a heat rate of approximately 7.55 GJ/MWh, and a non-fuel variable O&M cost (VOM) of approximately 5.5 $/MWh. *Gas price + CO2price * 0.053 tCO2/MWh = $20-25 (the LNG price, which is all inclusive)* Based on this 7.55x20 (or 25) +5.5: SRMC = $156.5 - $194.25.

126. The potential impact of this option on average spot electricity prices and forward electricity prices are presented in the table below.

	Commentary	**Price reductions, relative to other options (listed strongest to least effect)**
Potential impact on average spot electricity prices	This portfolio is expected to provide lower prices than LNG option because: • CCGTs (like TCC) are more efficient than peakers, delivering lower cost electricity. This increases the capping effect on spot prices relative to just establishing an LNG import facility. • This option adds more capacity, avoiding the need for higher priced existing options, including diesel and demand response.	Rankine-based option (2) Mid range: LNG import facility (1), Low Capex portfolio (4) and **Additional Cover portfolio (5)**) Peaker-based option(3)
Potential impact on average forward contract prices	It can be expected that this would have greater reduction than the LNG import facility-only, but not as much as the Rankine-based option.	

Timeliness

127. Refurbishing TCC will require agreement with Contact Energy but could be achieved by winter 2027. An LNG import facility could be in place between 2027 and 2029, depending on the preferred pathway and project.

Flexibility

128. For the LNG component, the flexibility will be the same as Option 1. In short:

- fuel will likely be purchased on the spot market which means that there are many supply sources, and that deliveries are flexible on timing,
- a conventional scale option would involve the charter of an FSRU with a storage capacity of 4PJ which provides considerable flexibility to call on LNG from the spot market if and when needed, and
- there are options to “sub-let” the vessel if it is not required and/or not renew the charter at the term of the contract.

129. Refurbishment of TCC provides a further insurance component (resilience) to our dry year cover:

- if other kit, including existing Rankines fail, it can provide spare capacity/cover, and
- it provides extra cover in particularly severe dry years (or other stressed scenarios).

Spillover costs and benefits

Emissions

130. Gas-fired generation is less emissions intensive than coal. LNG does have its own emissions (as outlined under option one).

Broader economic impacts

131. LNG is likely to provide additional gas supply for some direct users, including less price sensitive industrials, commercial and residential supply. Some industrial users may need to continue to use gas in future. This is especially important for firms that are reliant on high temperature or gas-specific processes (e.g. chemical, metal fabricators). For other firms, LNG may be affordable short-term while they transition to alternative energy forms.

132. LNG would set a gas ceiling price of $20-25/GJ. That is, domestic wholesale gas prices (currently rising rapidly given the decline of domestic gas supply) would not pass the LNG price.

133. Given the shortfall in domestic supply, import of LNG may also see domestic gas rise more quickly to (just below) the LNG price of $25/GJ than it otherwise would have. However, if gas supply continues to decline, domestic gas prices will almost certainly reach $25/GJ, and possibly more. Further analysis on the options for mitigating upward price pressures are provided in section on *Additional analysis of LNG import option.*

Additional analysis on LNG

134. The analysis above shows that LNG is the preferred option. This section sets out further considerations in respect of LNG:

- LNG supply costs – a more detailed look at the basis for the $20-25 price estimate used in this business case.
- LNG price effects on the electricity market under a range of scenarios and a normal (P50) year and 1-in-20 weather (P95) year.
- LNG effects on the domestic gas market – looking at potential benefits, and options to reduce the potential negative effects of pricing up to LNG.

LNG Supply Costs

135. The landed price of LNG has been in the order of $20-25 on the global market until recently, in part driven by an increase in demand resulting from gas supply issues in Europe.

136. Forward prices have fallen recently, to around NZ$17/GJ[31]. Substantial investment into new production is underway, with production expected to increase 50% in the next five years, substantially in excess of expected demand growth (1-2% per annum). This is likely to see prices fall to lower levels for the next 10 years, before finding a new equilibrium around 2035. Some commentators suggest prices might drop by as much as 50%. The IEA has suggested, that based on production, the forward price curve could fall as low as $13/GJ.[32]

137. In addition to the wholesale or spot price, the following additional costs will be incurred, and included in the price paid by the electricity generator or user:

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[31] Source: Gas 2025 – Analysis - IEA

[32] Source: Gas 2025 – Analysis - IEA

- Emissions Trading Scheme (ETS): currently about $3/GJ for LNG.
- Storage and transmission costs: the level of storage required will depend on the import model, and transmission costs will depend on connection charges from the LNG import terminal to the transmission network; and the users' connection costs. Commercial Information
  Commercial Information

Cost breakdown of LNG to user	**Estimated $/GJ**
Forward market price:	$13-17/GJ
ETS costs	$3/GJ
Storage and transmission	Commercial Infor
Re-gas costs (process of warming LNG for injection to the gas network)	Commercial Information
Total cost to user **(generators and direct users)**	**$20-25/GJ** (plus unknowns set out below)

- There may be additional costs associated with delivery to New Zealand, these could include:
  - New Zealand will likely be purchasing from the spot market, which entails a premium cost over and above the forward price market.
  - Additional costs if imports are sourced at a distance (shipping costs)
  - The availability of supply that meets New Zealand specifications (Wobbe index) or treatment of the natural gas to meet specifications
  - Possible price premiums if the import facility has bespoke requirements: for example, if an LNG cargo can only be partially off-loaded, or off-loaded in portions while the LNG is re-gassed.
  - Variation may also occur, based on changes in the exchange rate.

138. Separately, BCG recently estimated the LNG price charged to users at $22–25 per GJ which includes $4–5 per GJ for regasification and carbon.[33]

139. We do not consider that the range of potential prices of LNG significantly impacts on the case for an import facility, as the main benefits stem from the reduction in the dry year risk premium caused by the availability of LNG, with additional benefit of using LNG rather than diesel-fired generation (capping spot prices at a much lower level).

140. The price of LNG will, however, affect the uptake of LNG by industrial users.

[33] Source: energy-to-grow-full-report-vfinal.pdf

LNG price effects on the electricity market

141. MBIE commissioned Concept Consulting to undertake modelling and analysis of LNG impacts under various scenarios. The modelling produced the following expected impacts of LNG on average New Zealand electricity spot prices under various scenarios, for illustrative 2028 and 2035 years.

Impacts of LNG on electricity prices in different future scenarios

	In 2028	**Expected impact of LNG on annual average NZ electricity spot prices ($/MWh)**	
	Scenario	**Median weather year (P50 price effect)**	**Dry year (P95 price effect)**
Scenarios where modelling indicates LNG reduces spot prices	Central case but only 2 Rankines	- $18 ($217 ➔ $199)	- $54 ($501 ➔ $447)
	Central 2028 case (ie MBIE view of most likely 2028 counterfactual): demand and supply out of balance, 3 Rankines, LNG price of $20/GJ	- $11 ($200 ➔ $189)	- $58 ($338 ➔ $280)
	Central case but with supply/demand better in balance	- $2 ($141➔ $139)	- $9 ($215 ➔ $206)
Scenarios where modelling indicates LNG increases spot prices	Central case but with Tariki storage and local gas prices tied to LNG price at $25/GJ	+ $20 ($175 ➔ $195)	+ $8 ($244 ➔ $252)
	Central case but with supply/demand better in balance, Tariki storage and local gas prices tied to LNG price at $25/GJ	+ $20 ($124 ➔ $144)	+ $20 ($181 ➔ $201)

	In 2035	**Expected impact of LNG on annual average NZ electricity spot prices ($/MWh)**	
	Scenario	**Median weather year (P50 price effect)**	**Dry year (P95 price effect)**
Scenarios where modelling indicates LNG generally reduces spot prices	Central case but demand/supply out of balance	- $3 ($141 ➔ $138)	- $44 ($328 ➔ $285)
	Central 2035 case (i.e. MBIE view of most likely 2035 counterfactual): demand and supply in balance, 2 Rankines, LNG price of $25/GJ	+ $1 ($93 ➔ $94)	- $42 ($256 ➔ $213)
	Central case but 3 Rankines	$0 ($96 ➔ $96)	- $32 ($222 ➔ $189)
	Central case but Tariki storage (and 2 Rankines)	+ $3 ($91 ➔ $94)	- $2 ($206 ➔ $204)

142. The modelling results presented here come from Concept's proprietary New Zealand electricity market model, 'ORC'. This is a model that predicts how New Zealand's electricity system will likely develop over time and forecasts the prices that could eventuate in that market. The model does this by simulating the operation of the electricity system, given certain assumptions about the level and pattern of future demand, and the resources (generation, batteries, demand response, inter-island transmission capacity etc) available to satisfy projected demand.

143. MBIE worked with Concept to establish a range of scenarios covering key assumptions relevant to our LNG analysis, such as future supply/demand balance, local gas production and pricing, LNG prices, future availability of aging thermal generation assets, and the addition of new gas storage.

144. At its core ORC is a short-run marginal cost-based[34] model that finds the least-cost solution to providing enough generation and reserves to meet demand. This provided the insights presented above into future electricity spot prices, with and without an LNG facility, under the range of scenarios developed for the analysis. The prices reflected in the results table above are time-weighted average New Zealand spot electricity prices. It is important to note that prices would be expected to vary at different times of the day or year and at different locations across the country. Nevertheless, the estimated effects on average prices are a meaningful indication of the likely impact of adding an LNG facility.

145. For a given modelled future year, ORC is run across 43 possible 'weather years' using fully-coincident historical hydro inflows, wind flows, sunshine, and demand levels. This allows capture of concurrence of renewable and demand 'tails' that drive outcomes at times of market stress. These are important considerations for modelling to support our analysis of LNG where the distribution of outcomes across different weather conditions, particularly adverse weather years, is key to understanding the "insurance" that LNG can provide. The "P95" results presented above reflect expected spot prices in an extreme adverse weather year (approximately 1-in-20 year events), whereas the "P50" results reflect expected spot prices for the median year.

146. ORC includes a detailed gas supply model. This considers the effect of gas storage, gas diversion from other major users, and limited flexibility from gas fields. This has assisted our understanding of how forecast LNG impacts might change if additional gas storage came into the New Zealand system.

147. ORC can be run in two "modes", both of which are used to support this LNG analysis:

- In near-term mode (1-3 years ahead), generation build is an input assumption, and the model solves for prices with the specified generation fleet. For this LNG analysis, we have looked at the 2028 year, and constructed several sets of input assumptions to cover possible scenarios, such as supply/demand being imbalanced, loss of one of the three Rankines, addition of gas storage, and local gas prices being tied to LNG prices.
- In long-term mode (5+ years ahead), the model optimises the building of the generation fleet based on input assumptions for cost trajectories and volumes of system resources that can be developed (or retired). The model builds sufficient new system resources (renewable or thermal stations, batteries) such that developers receive revenue adequacy for their projects. We have looked at the 2035 year, and constructed a similar range of scenarios.

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34 Short-run marginal costs in the model are the costs for each generation plant to cover fuel, variable operating and maintenance, and carbon.

148. A key feature of ORC is that it operates fully chronologically using an hourly timestep. This allows it to include important dispatch and capacity considerations involved with running the New Zealand electricity system such as “slow start” thermal operation, station outages (important given our aging thermal assets), and optimised grid battery operation and EV charging.

149. It is important to acknowledge some limitations of the modelling approach, in particular:

- ORC represents a collective New Zealand-wide approach and does not capture individual market participant behaviours that might be driven by other factors such as portfolio effects across other aspects of participants’ business.
- It does not model the different risk preferences of different parties – some might be more risk neutral whereas others might be more risk averse when making investment decisions.
- Some real-world uncertainties are not included in the model’s decision-making, such as uncertainties in future fuel costs, carbon costs, capital costs, interest rates, exchange rates, market rule changes. Each of these is reflected in the assumptions for a given scenario. Understanding the potential effect of variations in these elements would require running multiple different scenarios with these elements varied. This has not been done for this modelling exercise.
- Analysis is generally based on public information sources – it is possible there is relevant information known to generation plant owners and other market participants that is not reflected in this analysis that could affect the results.
- While the model has used 43 weather years, as a representative sample of possible weather outcomes, there could be outcomes that fall outside of this range.
- The transmission grid will continue to be upgraded to reduce the effects of transmission constraints.
- Demand is assumed to persist even after very large prices for extended periods, that is, there is demand response modelled but it is assumed the demand does not permanently exit the market but will come back when prices reduce.

LNG price effects on the gas market

150. As previously stated, it may be assumed that LNG would set a gas ceiling price of $20-25/GJ as domestic prices will not pass the LNG price.

151. Given the shortfall in domestic supply, and forecasted decrease in gas production from 107PJ in 2025 to 67PJ in 2030, we may see a rapid rise in natural gas prices as consumers will be competing for a dwindling resource. Provided there is not an unexpected increase in natural gas supply (for example through new finds, unexpected increase in field reserves), a point is likely to be reached where LNG and natural gas prices will converge.

152. Industrial users are likely to be most affected by changing prices. Concerns have been raised about LNG permanently setting the domestic gas market price. Given industrial contracts are already being struck at comparable prices, LNG may in fact stem price escalation in the short term. However, the effect on market dynamics is a valid concern longer term.

153. The Government already has several programmes in place that will support “de-linking” of the two markets:

    - Gas co-investment fund, which will:

    - maximise the domestic supply of natural gas by maximising take from existing fields, and potentially making new finds, and
    - support investment in ancillary infrastructure including gas storage (this benefits the gas market generally, with and without LNG).
- Gas market transparency (Action 2.4 of the Government's Energy Package) which will ensure that the market is well-informed about contract prices, and support monitoring of competition.
- EECA support for transition will enable firms to make informed investment choices, and reduce New Zealand's reliance on natural gas where it makes economic sense to do so.

154. In addition, the configuration of the LNG requirements set out in the procurement documents will limit the period of time that LNG is available in market. Requirements have been set at delivery capability of 12PJ over three months. This means that in a dry year, LNG can be imported over the period where coverage is required, rather than having to be "drip fed" into the gas system over the course of a year (as proposed in some smaller scale options). This means that (other than in an economy-wide structural shortage), LNG would only set the domestic gas price for around three months every three to five years.

155. At the point where New Zealand is structurally short of natural gas, LNG will in fact cap domestic gas prices. As we have seen with recent industrial contracts, this could have benefit for direct users, as well as electricity consumers.

156. The recent BCG report, Energy to Grow: Securing New Zealand's Future, also notes the importance of de-linking the two markets, and recommends the above steps. It goes further in one respect, by recommending greater support for gas transition for direct users, thereby reducing reliance on natural gas in total, and therefore LNG.

Commercial Case

Key points

- **We are following all-of-government procurement practices, albeit on a truncated timeline.**
- **There is substantial market capability and interest in providing an LNG import facility in New Zealand.**

Purpose of this commercial case

157. Assuming the LNG option identified in the economic case is preferred, this commercial case sets out how the Crown will proceed with the next phase of procurement for an LNG import facility and associated services to deliver 12PJ of LNG to enable up to 1.5 TWh of additional dry year cover.

158. The preferred commercial approach is an integrated terminal services model with a single contracted provider for a floating storage (and regasification) unit and onshore works, with a split-package fallback if that offers better value or capacity.

159. The commercial case:

- explains how current and planned market engagement is being used to secure competitive offers,
- sets out the delivery model, packaging and route to market,
- describes the intended allocation of key risks and the main contractual terms,
- outlines probity, governance and broader-outcome arrangements, and
- provides an indicative procurement and delivery timetable, and the main dependencies and conditions.

160. This commercial case applies the New Zealand Government Procurement Rules.

Market engagement and lessons from the ROI / ADS

161. MBIE has initiated a Registration of Interest (ROI), which included an invitation for submissions for Accelerated Delivery Solutions (ADS). This process is testing market capability, delivery models and feasible timeframes for an LNG import facility. Submissions closed on 17 November, with 25 respondents, including Comme [redacted] proposals for delivery in 2027.

162. Early feedback from the ROI / ADS process indicates that:

- There is credible interest in providing LNG import terminal services in New Zealand, including on an accelerated timeline.
- Commercial Information [redacted]
- Commercial Information [redacted]
- Commercial Information [redacted]

- Commercial Information [redacted]
- Commercial Information [redacted]

163. These insights are being used to shape the commercial strategy, draft contract structures and the evaluation approach for the next phase of procurement.

Commercial objectives

164. The commercial approach reflects the conclusions of the strategic and economic cases and is consistent with the New Zealand Government Procurement Rules. It is structured around the following objectives:

   - **Securing dry year cover** of up to 1.5 TWh by 2029 at least cost:
     - Able to deliver 12 PJ of gas over a three-month period, with options to scale if required.
     - A contractual availability profile that aligns with winter risk periods, with clear incentives for performance and defined consequences for under-performance.
   - **Providing bankable, long-term (indicatively 15-25 years) service arrangements** of LNG terminal capacity and associated onshore works, structured so that it is bankable for suppliers and financeable under a levy-funded cost-recovery model (limiting any upfront capital requirements for the Crown). The commercial terms should support transparent recovery of amortised capex and operating costs, with clear indexation, foreign-exchange and change-in-law settings.
   - **Preserving market incentives and price signals.** We will procure terminal access and thereby security of fuel supply, not dispatch or wholesale price outcomes, so that generators retain responsibility for investment and operation decisions. This is expected to support a reduction in the dry-year risk premium in electricity prices, while maintaining incentives for private investment in generation and other firming solutions over time.
   - **Allocating risk clearly and manage residual Crown exposure.** Construction, operational and interface risks will be allocated to the parties best placed to manage them, with clear obligations and performance regimes. Any residual Crown risks will be explicitly identified – including policy, regulatory and long-duration availability risks – and managed through contingency, governance and approval settings.
   - **Supporting broader outcomes proportionately,** including proportional requirements and evaluation criteria for emissions reduction, resource efficiency, skills development, regional employment and Māori participation. These should reflect realistic market capacity, so that they do not compromise delivery timeframes, safety, or value for money.
   - **Maintaining probity and value for money** through a transparent, contestable procurement process with appropriate probity oversight, documentation, and debrief practices. Proposals will be evaluated on a whole-of-life cost to the Crown, quality of solution, delivery confidence, risk, and broader outcomes, using a price–quality (weighted attributes) approach.

Plan

Approach to market

165. We are using a staged approach, designed to preserve competitive tension through to contract close.

166. The first stage of procurement – the ROI with ADS submissions – has closed. This allowed early testing or market interest. MBIE is currently evaluating the responses, which will provide information on market capability and delivery models.

167. The preferred commercial route is an integrated terminal services model, under which a single counterparty would:

- deliver and operate the terminal and onshore enabling works,
- provide terminal services under a long-term terminal use agreement (TUA),
- meet defined availability and performance standards, focused on winter readiness by 2029 (or earlier, as determined by the accelerated delivery process), and
- provide non-discriminatory access consistent with the gas transmission code and the dry-year regulatory framework.

168. If market feedback indicates that a split structure would provide better value or capacity, the Crown would retain the option of separate packages for:

- terminal services (through the TUA),
- onshore enabling works (early contractor involvement, followed by design and construction),
- gas transport and market interface services, and
- optional LNG supply (spot and short-term cargoes).

169. The intended process is:

- **Stage 1 – ROI (currently in evaluation phase):**
  - Issued an ROI to identify capable respondents with LNG import facility experience and New Zealand operating capability.
  - Published high-level commercial principles, minimum pre-conditions, and evaluation criteria.
  - Shortlisting of respondents for the RFP stage is underway; alongside initial assessment of ADS proposals.
  - In parallel, negotiate an agreement with Port Taranaki (and any other relevant port) covering indicative berth access, interfaces, co-operation on consenting and competition-law settings.
- **Stage 2 – RFP: Targeted accelerated delivery round or standard RFP for qualified participants**
  - Invite shortlisted respondents to submit detailed proposals under the integrated model, with the option to propose a split-package variant.
  - Issue near-final contract drafts, including TUA and onshore works schedules, supported by interface matrices.
  - Run managed interactive sessions to clarify scope, risk allocation, programme and broader outcomes.
- **Stage 3 – down-select and close contract:**
  - Identify a preferred tenderer (or preferred tenderers for split packages), subject to confirmatory due diligence, finalisation of commercial terms and internal approvals.
  - Proposals would be evaluated using a price–quality (weighted attributes) method, with minimum technical thresholds and a focus on whole-of-life cost, winter availability, delivery confidence, risk management and broader outcomes.

Allocation of risk

170. Risk allocation will follow a clear principle: allocate risk to the party best placed to manage it, while explicitly recording any residual Crown exposure. The below risks have been identified.

Commercial Information

Achievement of broader outcomes

182. Broader outcomes would be included in a way that is proportionate to project size and market capacity, and that does not compromise safety, schedule or value for money.

183. The focus areas are expected to include:

- **Emissions and resource efficiency** – requirements for energy-efficient plant, quantified emissions plans, and waste minimisation in design and construction.
- **Skills and employment** – expectations for training and apprenticeships, with targets scaled to contract value and realistic local labour market capacity.
- **Māori and regional participation** – opportunities for Māori and regional suppliers, including sub-contracting and fair payment terms.

184. These expectations would be reflected in RFP evaluation criteria and, where appropriate, in contract key performance indicators, so that delivery can be monitored and adjusted over time.

Governance and assurance

185. Project governance and assurance arrangements would support disciplined decision-making and control of scope, cost, schedule and risk.

186. Key elements are expected to include:

- An Executive Steering Group providing overall direction, endorsing procurement strategy, approving RFP release / engagement with selected ADS proposals, preferred tenderer selection, contract terms and notice to proceed.
- An integrated client team (commercial, technical, legal and programme) managing day-to-day engagement with suppliers and the port.
- Independent commercial and technical peer reviews of the TUA, onshore contracts, risk allocation and TOC (where applicable).
- Periodic gateway-style or equivalent assurance reviews as appropriate, including pre-award and pre-financial close stages.
- Monthly reporting on risk, cost, schedule, winter availability profile and broader-outcome delivery.

187. These arrangements would sit alongside standard MBIE procurement and delegations processes.

188. Arrangements for contract management and benefits realisation will be aligned with this governance model.

Programme, dependencies and conditions precedent

189. The procurement and delivery programme would be structured to achieve winter 2029 readiness while retaining flexibility if an accelerated option proves feasible.

190. Indicative milestones are:

Commercial Information

Commercial Information

191. Key dependencies and conditions before contract close and notice to proceed include:

Commercial Information

192. Once these conditions are met, the project would move into detailed design, construction and commissioning under the contractual arrangements described above.

Financial Case

Key points

- **The LNG facility will likely be a contracted service, rather than a facility owned by the Crown.**
- **All electricity users benefit from an LNG import facility, as improved security of supply would reduce average forward prices (and spot prices in a dry year). The benefit of that coverage is proportional to use.**
- **Recovering the annual cost of the service primarily through a levy on the electricity industry at a /MWh rate reflects these benefits. This levy could be part of, or sit alongside, the current Electricity Industry Levy.**
- **We anticipate that the facility could also generate some commercial revenue, by providing services to direct gas users. This commercial revenue would offset levy charges.**
- **We expect the supply and purchase of LNG will be fully commercial, however, pending completion of commercial arrangements, it is not clear if the government will need to play some sort of aggregation role.**
- **Other project-specific ancillary services may need to be considered** Commercial Information [redacted] Commercial Information [redacted]

Purpose of this financial case

193. The financial case sets out the necessary funding arrangements for the successful delivery and operation of the LNG import facility. It also flags the potential financial implications of the operation of an LNG supply system.

Approach for Cost Recovery

194. The Stage One Cost Recovery Impact Statement goes into the basis for cost recovery, in short, we are applying the following approach to cost recovery:

- **Over time, the LNG facility should be fully cost-recovered from energy users**, rather than the Crown. The key market failure motivating the Government's involvement is co-ordination, which is not a strong basis for financial support from general taxation.
- The facility should generate commercial revenue from direct gas users, where appropriate via a "re-gas fee" in order to:
  - avoid free-riding - direct gas users should contribute to the costs of the LNG system, where they are sourcing gas, (if the levy is on the electricity system only), and
  - reduce potential for distortionary pricing of LNG relative to other fuels.
- Commercial revenue is not expected to recover a significant proportion of costs. This means additional sources of revenue will be needed (e.g. through a levy).
- If direct gas users become a substantial beneficiary of LNG imports, then recovery via a gas levy may become appropriate in the future.

- **LNG importation is an insurance product for dry year cover for the electricity system**. This means all electricity users benefit from the availability of an LNG facility because it provides security of (fuel) supply, reducing average forward prices (as well as spot prices during dry years). It is therefore appropriate to recover costs of the facility via a levy across the electricity system.
- **The benefit of that coverage is proportional to use**, as the key impact is prices, and therefore electricity cost savings are greater the more electricity a consumer/business uses. This means a levy charged as $/MWh is more benefit reflective than (for example) a flat rate on all users.
- **The existing Electricity Industry Levy provides an opportunity for cost-effective collection.** A levy on electricity for the facility could be collected either as part of or alongside the Electricity Industry Levy.

Costs for recovery

195. The LNG import terminal is a lease arrangement, not an ownership one. The Crown, therefore, is unlikely to need to put forward capital upfront. Costs for the LNG import service are likely to be included in an annual charter fee (and will vary considerably, based on the project).

196. Confidential advice to Government

Ancillary services

Commercial Information

LNG supply

198. The supply of the LNG is expected to be a commercial activity, potentially with little or no government involvement. Confidential advice to Government

Confidential advice to Government

Working capital

199. Working capital may be required where there are upfront costs (project dependent), and/or where additional working capital is required to set up the function/business unit overseeing the LNG operation.

Financial overview of the LNG project

200. The ROI process has resulted in Comme accelerated delivery options being proposed. Costs are highly indicative at this stage. The economic case presented a higher-cost option as a conservative option for testing the value of an LNG import facility against other options for dry year cover (drawing on investigation work commissioned by New Zealand firms from UK Gas Strategies). The following table presents the range of costs actually submitted in the ROI process. These are indicative, and initial assessment have identified that additional costs are likely to emerge, for example, port works have not been fully costed.

Component	Illustrative Costs	Funded by
Whole of Life Costs (capital, and operating and maintenance costs)	Commercial Information	$2.05-4.10/MWh levy Potentially offset with commercial revenue
Annual charter fee	$90-180 million for 15 years	
LNG Supply	$13-17/GJ on forward market $3/GJ ETS costs Commercial Info storage and transmission Commercial re-gas costs $20-25/GJ Total Cost to user Plus potential additional costs outlined in the LNG supply section above	Commercial sales to generators and direct users
Storage	Unknown scale and cost	Mix of levy and sales revenue
Working capital	Unknown	Crown, could be levy recovered.

Mechanism for cost recovery

201. This section assumes that MBIE will continue to be the project owner. Financial arrangements may need to be adjusted for different ownership structures.

Establish a levy

202. We propose to establish a levy to recover all costs of an LNG import facility Confidential ad Confidential advice to Government At this stage, we recommend that this sit alongside (or possibly within) the Electricity Industry Levy. This approach will minimise compliance costs.

203. The levy will be offset with commercial revenue associated with the project. With annual adjustments (possibly smoothed over time) to account for variations. Specific arrangements with respect to commercial revenue will need to be made, based on the commercial agreement and operations of the successful LNG import project.

204. Assuming the administration of the LNG facility contract remains with MBIE, MBIE will require an appropriation (funded by the levy). Confidential advice to Government [redacted]

Funding model to be reviewed

205. At this stage, decisions on the final funding model will need to be adjusted for final commercial agreements. Over time, use of the LNG terminal is also likely to evolve which may suggest an alternative model is more appropriate. For example, if direct gas users were to become substantial importers of LNG, the scope of the levy may need to be changed to include a share charged to the gas system.

Management Case

Key points

- **MBIE continues to lead the procurement process for the import facility, but there are options to amend the Crown's institutional arrangements once the contract has been finalised.**
- **The Government is also developing legislation to remove regulatory barriers for the facility**Commercial Information [redacted]

Purpose of this management case

206. The management case provides a high-level approach for two aspects of the project:

- **The Crown's institutional arrangements prior to and after the contract has been finalised:** the management case sets out the existing institutional arrangements and the potential future approaches that the Crown can take for its role as the contractual counter-party. It provides potential options for operationalising any obligations or actions the Crown has once the contract has been finalised.
- **The legislative approach**: this sets out the high-level approach that the Government will take to ensure that the project has the necessary legislative consents, approvals and other matters, in time for the facility to be constructed and operational by winter 2027.

Approach – the Crown's institutional arrangements

MBIE continues to be the institutional lead on the procurement process until the contract is signed

207. MBIE has been leading the procurement process for the LNG import facility services. There is a team with a broad range of skillsets and expertise, including input from the MBIE Energy Markets branch, the MBIE procurement team, MBIE legal and external support has been contracted, specifically technical advisors and international legal counsel.

208. MBIE will continue to evolve the team to support both procurement and contract management in order to realise the project and maximise the benefits for New Zealand.

There are options to adjust the institutional arrangements once the contract has been signed

209. The Crown will be the contractual counter-party to the agreement.

Confidential advice to Government [redacted]

Confidential advice to Government

Approach – developing enabling legislation

The Government will likely develop legislation to remove regulatory barriers to the facility

213. To give surety that the facility can be constructed and operational by winter 2027, the Government may need to provide the necessary consents and approvals, with sufficient speed and certainty.

214. To provide this speed and certainty, the Government intends to develop legislation to remove regulatory barriers, in parallel with the procurement process. Confidential advice to Government

215. Confidential advice to Government

216. The legislation will also provide for the levy mechanism, addressed in the financial case above.

Annex One: Additional options considered, but not progressed to full assessment

The following table sets out further investment options that were considered, but ruled out at an early stage as not meeting minimum criteria.

Option	Description	Reason for exclusion
Hydro option – North Island	Pumped hydro scheme at Upper Moawhango in the central North Island that could and could add 1.5 TWh to system.	• Sits on defence land (concerns around losing training site); lack of iwi consensus; significant environmental impacts. • Requires major construction - delivery date around 2035.
Hydro option – South Island	Raising Meridian-owned Lake Pukaki by 30m which adds 3.5 TWh of storage.	• Requires major construction - delivery date around 2035.
Distributed demand response	Many large-scale electricity users (e.g. public services, commercials) have their own diesel fuelled back up generation that switches on during power outages. These users could potentially be paid to run their generators during a dry year to provide cover.	• The scale of generation available is likely to be small i.e. not meet or make significant contribution to a 1.5TWh requirement. • There is substantial work required to test the technical feasibility, including co-ordination, and payment for this form of demand response.
Geothermal for dry year cover	New geothermal generation targeted to dry year: • Generation to operate at reduced capacity in normal years (for operational reasons). • At an increased output mode in dry years to make up for the reduced hydro output.	• Holding cheap, renewable energy in reserve would be a significant departure from the current market model (where the cheapest form of generation is used first). • There would be (perceived) credibility issues about limiting deployment to dry years. This could have a chilling effect on investment, both in renewables and firm generation.
Lithium ion and other battery storage	Use grid scale battery energy storage systems for short term storage, load shifting and arbitrage. Using large utility scale or aggregated distributed batteries.	• This type of technology has not progressed sufficiently to meet long-duration cover needs. Grid-scale batteries typically store energy equivalent to 2 to 4 hours discharge at the rated capacity. This is a good technology for peaking requirements, or re-distributing solar production, but will not (yet) meet New Zealand's dry year cover requirements.
Rooftop solar	Incentivise significant rooftop solar uptake across residential, commercial, and industrial users	• Will not provide substantive additional energy during winter, when we are most likely to experience the dry-year problem.

Stage 1 Cost Recovery Impact Statement

Options for dry year risk cover – enabling cost recovery

Status quo

A source of firm and flexible electricity generation is required to address dry year risk in New Zealand

Approximately 85 percent of New Zealand's electricity is generated from renewable sources. Thermal fuels, including natural gas, are used to supplement electricity generation (also known as providing 'firm' generation) when renewable sources are insufficient – particularly during periods of low rainfall and/or with little wind, commonly referred to as dry years.

The energy system is vulnerable to fuel shortages due to (among other things):

- a decrease in natural gas production (currently only domestic with no imports)
- variability in the supply of electricity, including from greater intermittent (largely solar and wind) generation entering the system.

For example, in August 2024, hydro lakes dropped to 55 percent of the average levels for that time of year. This combined with an unexpected drop in gas supply resulted in spot prices exceeding $800 per megawatt hour ($/MWh).

There is a gap between what the market will in invest in for security of supply and what the Government considers optimal

Following 2024 electricity price spikes due to shortages, the Government commissioned an independent review of the electricity market.[1] The Frontier Economics report found that while the market design is successfully incentivising new renewable generation, it is failing to deliver investment in firm generation which can guarantee supply during dry years or periods of low wind and sun.

This is caused by a combination of investors facing: revenue risk (these are long lived assets, with uncertain revenue profiles), gas supply risk (from declining production), Environmental, Social, and Governance (ESG) expectations and concerns, and a free rider problem (generators prefer to buy firm generation on the spot market when required, rather than own the asset, leading to under-provision for coverage of sporadic events).

This gap is giving rise to:

- *Affordability issues*, as a risk premium is built into forward electricity prices, increasing the cost of supply. Wholesale electricity prices have more than doubled since 2017. There is now a $30-50/MWh dry year risk premium in forward contract prices, due to the uncertainty of cover in dry years.
- *Energy security concerns*, where there could be a physical shortage of electricity in the event of dry years (seldom seen as blackouts, but rather seen through sharp price rises, resulting in businesses curtailing production or closing).

[1] Review of electricity market performance | Ministry of Business, Innovation & Employment.

These issues are impacting the economy[2], and Government intervention is needed.

The Government and sector have taken actions to address security of supply issues

The electricity market is complex and actions are needed across a range of areas. These are outlined in the Government's Energy Package[3], and comprised of two workstreams:

- Investing in Energy Security
- Building Stronger Markets.

There is some sector activity, for example, the four gentailers have reached a non-binding agreement to investigate keeping Huntly Power Station's Rankine Units (scheduled for retirement) to remain in market and continue playing a role in managing dry year risk. However, these actions only maintain the current capacity. They do not add fuel or new firm generation.

Policy Rationale: Why a user charge? And what type is most appropriate?

The Government is intending to progress with an LNG import terminal

Demand for electricity is expected to increase significantly by 2050 and meeting this demand will require a significant increase in investment in generation. Future growth is expected to come from wind and solar generation, though these sources are intermittent. As well as addressing the status quo dry year gap, security of supply will be needed in the long term.

Providing dry year cover will support overall security of electricity supply objectives, and put downward pressure on prices that currently have a risk premium built in. This will benefit all electricity users.

The Government is intending to invest in/purchase Liquefied Natural Gas (LNG) import facility services.[4] Further decisions will be made in [redacted] which could affect the scope of this CRIS. An updated version will be provided if this is the case.

The case for Government to recover the costs of activities related to providing dry year cover

Dry year cover is an insurance product. It is purchasing capacity in case of a dry year. The key beneficiaries of that insurance – in this case an LNG import facility – are electricity users. They benefit in two ways:

- Reduced spot prices in dry years: an LNG import facility, and the resulting fuel supply could cap prices and generate reductions in spot prices of up to $50/MWh.[5]

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[2] By 2025, higher energy prices are estimated to have reduced New Zealand's Gross Domestic Product by $5.2 billion (1.25 percent), lowered real wages by 1.4 percent, cut household spending by 1.65 percent, and worsened the trade balance by $275 million.

[3] See: https://www.beehive.govt.nz/sites/default/files/2025-10/At%20a%20Glance%20-%20New%20Zealand%27s%20Energy%20Package.pdf

[4] There is no RIS required for the LNG import facility investment decision. There will, however, be a Supplementary Analysis Report (SAR) provided to support decisions about the enabling framework that Government intends to put in place to support the development of an LNG import facility.

[5] Modelling by Concept: worst case scenario: severe dry year, with thermal electricity plant outage.

- Reduced dry-year risk premium: a $10/MWh decrease could save users $400 million per annum.

An LNG import terminal will charge the Government an annual charter fee to recover capital costs over the period of the contract, annual operational costs, and a reasonable return. Confidenti

Confidential advice to Government

The levy is akin to an insurance premium for electricity users, providing security of supply that the market will not provide (as set out by the Frontier report, and discussed further below). This would be a new levy. A user charge is intended to ensure that those who may opt to import LNG for other purpose make a fair contribution to the costs of the facility.

Detail on how the levy applies will be made under subsequent regulations. We expect decisions will result in levy cost recovery for annual costs of an LNG import facility, less any commercial revenue earned.

Closing the gap for dry year risk benefits all electricity users by effectively insuring against the risk of supply shortages

The Government needs to provide this role as the market will not produce it alone. This market failure is evidenced by a series of commercial investigations into LNG import and other firming projects in New Zealand that have not moved to final investment decisions; and the Frontier Review of Electricity Market Performance[6]. This shows how the outputs are have characteristics of a merit good – that dry year cover is desired by the community (i.e. economically optimal for the system) but not provided by (or rational for) individual generators in the market.

Providing infrastructure to ensure gas supply for gas-fired electricity generation for firming in the event of dry years will benefit all electricity consumers. It puts downwards pressure on forward electricity prices (which directly link to retail costs) and provides assurance against physical electricity shortages (rare though these may be).

Cost recovery is appropriate to capture the collective benefits that arise specifically from security of supply infrastructure and generation, rather than the alternative option of funding through general taxation. A levy can be charged per MWh, and this reflects that the benefits are also proportional i.e. larger users get more benefit from dry year cover (compared with general taxation which would not necessarily be proportional).

The cost recovery regime is not intended to change the behaviour of those paying charges. Instead, it will overcome the problem of the lack of incentives and commercial barriers for those participants to invest in dry year cover in the New Zealand electricity market context. Rather than relying on individual participant(s) to invest in necessary solutions, the Government will provide the solution and charge participants to fill the gap – costs will then reflect socially optimal outcomes.

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[6] Review of electricity market performance | Ministry of Business, Innovation & Employment

A levy could be enabled under the Electricity Industry Act, and would operate alongside existing levies

Cost recovery is expected to be in the form of a levy on electricity industry participants[7] – depending on the intervention this will either be based on electricity use, or generation, and charged per MWh. However, the specific mechanism will be designed in light of final Government investment decisions, commercial arrangements and in consultation with the sector.

The rationale for this approach is that it is administratively efficient and transparent to recover costs from participants that operate within the electricity system (building off current levy arrangements) and can be done fairly (proportional to use).

Alongside consumers, electricity generators and retailers benefit from being able to build and supply other generation, knowing they have access to firming (i.e. reserve electricity capacity to support intermittent wind and solar for example) in the event of a dry year. These participants can also be seen as 'risk exacerbators' (i.e. organisations whose actions make it necessary for government to become involved). This is because participants are not sufficiently incentivised to provide dry year cover, which is now resulting in government intervention. Risk exacerbators (generators in this case) can also pay for cost recovery charges, alongside people who benefit (electricity consumers, who will experience pass on).

The scale of and mechanism of any commercial revenue will depend on the nature of the LNG import facility service procured. Any levy will be adjusted for commercial revenue received. The Government does not intend to make a profit on the service.

The proposed collection method will be consistent with how electricity levies are imposed on bills already in New Zealand, as well as international cost recovery policies to fund infrastructure and support energy security.

Examples of comparable levies

There are currently existing charges under the *Electricity Industry Act 2010*, which allow the Electricity Authority (EA) to cost recover from industry participants (e.g. generators, purchasers, distributors) for performance of its functions to regulate the industry. A portion of the EA levy on participants (including some existing functions related to security or emergency events) is generally passed on to electricity consumers (around 0.4 percent of a typical household bill).

As an international example, Singapore expanded an LNG terminal beyond its operating capacity with a strategic reserve to support greater security, reliability and optionality of gas supply, with the associated costs recovered via a gas system charge.[8]

We expect the cost of the levy to be more than offset by downward movements in prices

We expect that cost recovery will be up to $4/MWh, generating $170m per annum revenue. However, final figures are dependent on the cost of the preferred LNG import facility project.

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[7] According to the EA there are around 86 generators (including generator-retailers), and 68 retailers (including generator-retailers).

[8] EMA-Regulations-Policies-Info-Paper-Policy-Recovery-Strategic-LNG-Terminal-Capacity-Cost.pdf

Currently forward wholesale electricity prices include a $30-50/MWh risk premium. As noted above, there is likely to be downward pressure on both forward contracts, and dry-year spot prices. If these forward contracts reduce even by just $10 (20-30% reduction in risk premium), this would more than offset cost recovery.

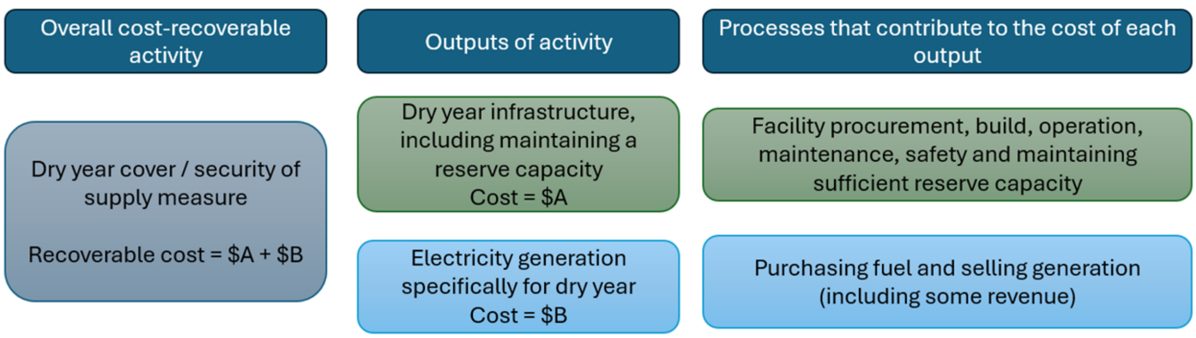
The extent to which this downward pressure actually results in a reduction in electricity bills will depend on a range of market dynamics.

However, the levy itself will be paid by electricity industry participants (additional to what they already pay under existing levies). These charges will likely to be passed on to end electricity consumers who will benefit in the form of reliable electricity and lower long-term electricity prices.

High level cost recovery model (the level of the proposed fee and its cost components)

An enabling power for dry year cover is needed while decisions are pending; so the activity, outputs and associated costs are uncertain

Government is still considering options for dry year cover. Depending on the option(s) agreed, the activities, outputs and associated costs may differ, however a high-level diagram below shows what this could look like.



Cost A is likely to be an annualised cost recovery of capital costs (either direct investment or paying for the fixed costs of a service). We anticipate Cost $B will be primarily recovered by commercial revenue. The extent of commercial revenue that could be generated in respect of Cost $A will be project dependent.

The cost recovery would be via a $/MWh levy on electricity generated and/or purchased by electricity participants. This essentially adds a dry year ‘insurance premium’ that is proportional to the electricity used. This may need to be reviewed over time, for example, if LNG use becomes more widespread across the economy.

Further work will be undertaken on more detailed cost estimates once procurement processes are complete.

The most likely investment is an LNG import facility

The Government has released a Request for Information (ROI) seeking proposals for building LNG Facility Services in New Zealand. This is the preferred short-term investment in dry year cover. LNG Facility Services would allow New Zealand to import LNG, re-gas, and deliver it through existing gas pipelines for gas-fired firm electricity generation.[9]

The current procurement is considering the establishment of only the LNG facility, not the purchase of fuel for generation (i.e. the outputs are the first green row in the diagram above). Ancillary services, potentially including supply agreements and storage, may also be required Confidential advice to Government

Cabinet is considering a range of options with different cost estimates, and the following provides an illustrative example from earlier investigations into options.

Commercial-In-Confidence

Infrastructure costs *for conventional scale LNG import terminal[10]:*

- This is estimated to have a cost of Commercial Information per annum or a whole of life cost of Commercial Information and could commence as early as 2029.
- Full cost recovery of this is estimated to be just under $4/MWh.
- As mentioned above, some commercial revenues would likely be available to offset some of this cost, however scale is uncertain at this stage.
- Scaled options may also be available.

These figures are initial estimates only (based on previous analysis done by the Gas Security Working Group) and would depend highly on the individual proposals received in the current ROI, and any future market engagement. We would consult on costs, including potential commercial revenues as part of developing a specific levy.

Consultation

No consultation has been taken as there has been very limited time to develop proposals from the time Government decided to proceed with procurement. In addition as the actual LNG import facility project could vary considerably in configuration and cost, it would be difficult to meaningfully engage in public consultation, and targeted consultation would involve talking to parties with commercial interests in the project.

Subsequent consultation on the cost recovery elements of the policy decision (as well as a SAR) will be undertaken in the development of regulations. At this stage the Government requires an enabling power to create a cost recovery mechanism supporting an LNG import facility, and potentially additional dry year cover options.

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[9] Gas-fired generation ran at about two-thirds capacity in 2024 due to the decline in domestic gas supply.

[10] This involves: a semi-permanently moored ship acting as a floating storage unit (FSU), either in a port or offshore, that holds the LNG while it is being 're-gasified'; a second ship – LNG Carrier – that delivers up to 4 petajoule (PJ) of gas to the FSU in a ship-to-ship transfer; regasification plant (either onboard the FSU, or stand-alone) that warms the LNG to a gaseous state for injection to the gas transmission system; and a high-pressure pipe connecting the re-gasification unit to the main gas transmission system.

Climate implications of policy assessment: Disclosure sheet

This disclosure sheet provides the responsible department's best estimate of the greenhouse gas emissions impacts for Aotearoa New Zealand that would arise from the implementation of the policy proposal or option described below. It provides supplementary analysis following Cabinet policy decisions. It is broken down by periods that align with Aotearoa New Zealand's emissions budgets.

Section 1: General information

General information	
Name/title of policy proposal or policy option:	Importing LNG in dry years
Agency responsible for the Cabinet paper:	MBIE
Date finalised:	9 December 2025
Short description of the policy proposal:	Importing Liquefied Natural Gas (LNG) with the principal purpose of addressing dry year electricity generation risk

Section 2: Greenhouse gas emission impacts

Sector & source	Changes in greenhouse gas emissions in tonnes of carbon dioxide equivalent (CO_2-e)					
	2020–25	**2026–30**	**2031–35**	**2036–40**	**2041–45**	**2046–50**	**Cumulative impact**
Electricity		-0.244M	-0.040M				-0.284M
Transport							
Industry							
Waste							
Agriculture							
Land use, land-use change and forestry							

Sector & source	Changes in greenhouse gas emissions in tonnes of carbon dioxide equivalent (CO_2-e)						
	2020–25	2026–30	2031–35	2036–40	2041–45	2046–50	Cumulative impact
Total		-0.244M	-0.040M				-0.284M

Section 3: Additional information

Additional information
Scope of assessment This climate implications of policy assessment (**CIPA**) investigates the emissions impact of the importation of LNG for electricity generation in a 'dry year' scenario out to 2035. The policy proposal is to establish an LNG import facility to enable LNG importation for electricity generation as "dry-year cover" for periods when renewable generation is adversely affected by weather and is insufficient to meet electricity demand. **Background/context** • The total volume of natural gas for electricity generation is diminishing as the proportion of renewable generation grows. However, natural gas will remain a vital fuel for firming electricity generation in dry years (where hydro inflows are low) for the foreseeable future, until technological alternatives in battery and energy storage systems can be introduced. • In 2024, total consumption of domestic natural gas was 117.7 petajoules (**PJ**), 23 per cent lower than in 2023. The breakdown of the 2024 gas consumption by sector is as follows: - 38.7 PJ for electricity generation - 42.3 PJ for industrial energy use - 20.5 PJ for non-energy use - 16.2 PJ for other energy use. • In the baseline for the second emissions reduction plan (**ERP2**), gas use for electricity generation was forecast to be 34 PJ in 2025, falling to 31 PJ in 2035. • The latest outlook of domestic natural gas production (as at 1 January 2025) indicates faster-than-expected declines in production in coming years: - Domestic natural gas production in 2024 was about 119.6 PJ, down from 148.1 PJ in 2023[1]. - Domestic natural gas production is expected to further decline to 107 PJ in 2025 and then down to about 67 PJ by 2030. - By 2035, annual domestic natural gas production is expected to have declined to about 35 PJ. - In addition, we are aware of downside risks to production expectations that have emerged since the production outlook was publicly released by MBIE in June 2025.

[1] The total gas consumption figure is lower than the total production figure due to the presence of a gas storage facility, as well as losses and own use that occur at the point of production, transmission, and distribution of gas.

Additional information

- In an environment of declining gas production, New Zealand may not be able to rely on domestic natural gas to provide sufficient electricity firming generation capacity in dry years. A lack of reliable, dispatchable generation (firming) is likely to become an impediment to development of renewable energy over time.
- As LNG is a direct substitute for domestically produced natural gas, importation of LNG is a potential initiative for addressing the gas supply constraint in dry years. However, New Zealand currently lacks the necessary LNG importation facilities.
- LNG importation can provide flexible gas supply to New Zealand. This flexibility is currently provided by Methanex, which can reduce its gas use and allow a significant volume of gas to be redirected to electricity generation in a dry year. The flexibility provided by Methanex would be lost if it was to exit New Zealand due to the ongoing gas supply constraint.
- Natural gas is also an important source of energy for the industrial and commercial sectors. The increasing scarcity of domestic natural gas (and resulting price increases) will continue to be a factor in the business decision-making of industrial and commercial users of domestic natural gas to either moving to alternative energy sources (including electrification) or, in some cases, to exit the New Zealand market. Although the LNG importation facility might be used by sectors other than electricity generation (eg if local gas supply declines markedly), such gas use is not the driver of this policy proposal, which is for dry-year insurance. If LNG were to be used by commercial and industrial gas users, it would be displacing their existing use of domestically produced gas.

Key assumptions about domestic natural gas production and additional amount of gas needed for firming electricity generation in dry years

- Production profile of domestic natural gas in the coming years are as published as part of MBIE's petroleum reserves data[2]. We are aware of downside risks to this future supply outlook.
- Consumption of domestic natural gas or LNG for electricity generation covers baseload generation and firming generation.

Key assumptions about gas use in the LNG importation scenario

- If LNG is imported, it will be used primarily for firming electricity generation in dry years. Any surplus of imported LNG would be made available to industries at market prices.
- For the electricity sector, if LNG becomes available, the fuel mix for electricity generation would change. Results from Concept Consulting electricity market modelling (refer below) have been used as the basis for MBIE's estimation of the fuel mix change.
- LNG is assumed to have no impact on gas use by industrial, commercial and residential consumers, as it is only expected to be imported in a dry year to meet the needs of firming electricity generation. Nevertheless, we acknowledge that industrial, commercial and residential gas use could fall in the future if domestic gas continues to decline and gas prices increase significantly.
- We assume that the earliest possible time for the first LNG shipment to arrive in New Zealand is 2027. The LNG import volume would depend on the need of firming electricity generation.

Additional information

Key assumptions about wider benefits

- Importing LNG can be expected to deliver additional less direct benefits in reducing emissions by supporting electrification and renewable build (see caveats section below), but these wider benefits are not included in the modelling results.

Modelling approach

As an input to the MBIE's analysis of the case for LNG, MBIE engaged Concept Consulting to undertake modelling of the electricity system, with and without LNG, to assist in understanding the impacts of LNG on the electricity market under various scenarios for two representative future years: 2028 and 2035.

The modelling predicts how New Zealand's electricity system will likely develop over time by simulating system operation, given certain assumptions about the level and pattern of future demand, and the resources (generation, batteries, demand response, etc) available to satisfy projected demand. The modelling uses 43 historical weather years, as outcomes differ depending, for instance, on whether it is a dry hydrological or low wind year.

The Concept modelling is run in two "modes" to support MBIE's LNG analysis:

- In near-term mode (one to three years ahead), generation build is an input assumption, and the model solves for prices with the specified generation fleet. For the purposes of considering LNG as a dry-year insurance, MBIE's view of the most likely counterfactual for the representative 2028 year, as used in this CIPA, is that supply/demand are out of balance, the system still has all three Rankines (thermal generation plant owned by Genesis), there is no additional gas storage, LNG (if required) is $20/GJ, and local gas prices are not tied to LNG except when LNG is being imported.
- In long-term mode (more than five years ahead), the model optimises the building of the generation fleet based on input assumptions for cost trajectories and volumes of system resources that can be developed (or retired). The model builds sufficient new system resources (renewable or thermal stations, batteries) such that developers receive revenue adequacy for their projects. For the purposes of considering LNG as a dry-year insurance, MBIE's view of the most likely counterfactual for the representative 2035 year, as used in this CIPA, is that supply/demand are in balance, the system has two Rankines, there is no additional gas storage (recognising additional gas storage is an uncertainty), LNG (if required) is $25/GJ, and local gas prices are not tied to LNG except when LNG is being imported.

The table below shows Concept's modelling results on emissions from fuel consumption for electricity generation for the most likely scenario in the representative future years, 2028 and 2035. These are annual figures, averaged across all "weather years". Modelling results are shown both with and without LNG, thereby giving an estimation of the impacts of LNG for scenarios that are otherwise identical.

Table 1: Concept's modelling results for "with LNG" and "without LNG" scenarios in 2028 and 2035

	Emissions associated with fuel consumption for electricity generation ($MtCO_2$)			
	Coal	**Gas/LNG**	**Diesel**	**Total**
2028				
without LNG	1.101	0.668	0.013	1.782
with LNG	0.942	0.720	0.058	1.721

2035				
without LNG	0.218	0.169	0.012	0.399
with LNG	0.201	0.168	0.022	0.391

Note: The emissions factors for coal, gas and diesel are 0.089tCO_2/GJ, 0.053tCO_2/GJ and 0.070 tCO_2/GJ respectively.

Concept's modelling suggests that, if LNG was available, emissions from fuel consumption for electricity generation would be reduced by 0.061MtCO_2 in 2028, and by 0.008MtCO_2 in 2035.

As the Concept modelling was only undertaken for two representative years, there are no modelled emissions outcomes for other years. For this analysis, we have assumed that:

- For the second emission budget (**EB2**) (ie the 2027–2030 period), annual emissions reductions resulting from LNG in 2027, 2029 and 2030 are the same as that in 2028 (as modelled by Concept).
- For the third emission budget (**EB3**) (ie the 2031–2035 period), annual emissions reduction resulting from LNG in 2031–2034 are the same as that in 2035 (as modelled by Concept).

Estimates of emissions impacts

Table 2: Estimated emissions impacts of LNG import for EB2 and EB3 periods

	Emissions associated with fuel consumption for electricity generation (MtCO2)			
year	**Without LNG scenario**	**With LNG scenario**	**Difference**	**Emission Budget period totals**
2027	1.782	1.721	-0.061	
2028	1.782	1.721	-0.061	
2029	1.782	1.721	-0.061	
2030	1.782	1.721	-0.061	**-0.244**
2031	0.399	0.391	-0.008	
2032	0.399	0.391	-0.008	
2033	0.399	0.391	-0.008	
2034	0.399	0.391	-0.008	
2035	0.399	0.391	-0.008	**-0.04**

For completeness, we have compared the estimates for emissions associated with fuel consumption for electricity generation between the "With LNG scenario" and the baseline scenario for the emissions budget for the second emissions reduction plan (ERP2) (see the Annex).

Additional information

Caveats

There are a number of limitations of our modelling approach, including in particular:

- The estimates for years other than 2027 and 2035 could be slightly over- or under-estimated, as the Concept modelling was only undertaken for two representative years, and there are no modelled emissions outcomes for other years. As discussed above, we assume that reductions in annual emissions associated with fuel consumption for electricity generation are the same (0.061 $MtCO_2$) across all years in EB2, and 0.008 $MtCO_2$ across all years in EB3.
- Some real-world uncertainties cannot be modelled, such as uncertainties in future fuel costs, carbon costs, capital costs, interest rates, exchange rates, market rule changes.
- While Concept's model has used 43 weather years, as a representative sample of possible weather outcomes, the severity and duration of dry period could fall outside of the range of these sampled years.
- The modelling approach does not capture individual market participant behaviours that might be driven by other factors, such as risks preferences and portfolio effects across other aspects of participants' business.
- We are not privy to some relevant commercial information known to generation plant owners and other market participants only.
- Importing LNG can be expected to deliver additional less direct benefits in reducing emissions, which are not included above:
  - It supports increased investment in renewables by providing reliable backup electricity supply, which renewable developers need to make their projects bankable.
  - By reducing the risk of high electricity prices and uncertainty around security of supply, LNG can also be expected to support electrification decisions for commercial and industrial consumers.

Section 4: Quality assurance

Quality assurance

The Climate Implications of Policy Assessment (CIPA) team has been consulted and confirms that CIPA requirements do not apply to this policy proposal, as the threshold for significance is not met. The proposal involves establishing an LNG import facility for dry-year electricity generation and modelling costs and emissions out to 2035. Counterintuitively, modelling shows New Zealand's emissions would be lower with an LNG import terminal than with no additional dry-year policy. The emissions impact of this proposal is a reduction of 0.244 Mt CO_2-e in EB2 and 0.04 Mt CO_2-e in EB3, driven by changes in the fuel mix for electricity generation across LNG, diesel, and coal. In the modelling, LNG storage enables more hydropower over the course of the year, instead of needing to reserve it for dry-year risk. This reduces coal use on the grid and resulting in lower emissions compared to a scenario without an LNG import terminal, where more fossil generation is used throughout the year to preserve hydropower for dry-year risk. Although this proposal does not meet the CIPA threshold, its importance to the energy system has prompted extensive modelling. The CIPA team has reviewed the estimates at a high level and considers the modelling to follow good practice and use reasonable, balanced assumptions.

Annex: Estimates of emissions changes relative to ERP2 baseline

Below, for completeness, is the comparison of emissions associated with fuel consumption for electricity generation between an LNG importation scenario and the baseline scenario for the emissions budget for the second emissions reduction plan (**ERP2 baseline**).

MBIE extended Concept Consulting's data to other years based on linear interpolation. This fuel use data was compared against the ERP2 baseline, and the emissions impact was calculated based on the difference.

The data and results are shown in the table below.

Provisional results:

Electricity generation fuel consumption (PJ)

	ERP2 baseline			LNG import scenario[1]			Consumption relative to ERP2 baseline (PJ)			Emissions relative to ERP2 baseline[2] (Mt)			
year	Coal	Gas	Diesel	Coal	Gas (LNG inc)	Diesel	Coal	Gas	Diesel	Coal	Gas	Diesel	EBP totals
2027	7.0	30.5	0.1	11.8	15.1	0.9	4.7	- 15.4	0.8	0.42	- 0.8	0.06	
2028	7.7	31.3	0.1	10.6	13.6	0.8	2.9	- 17.7	0.7	0.26	- 0.9	0.05	
2029	2.5	30.3	0.1	9.4	12.1	0.8	6.9	- 18.2	0.6	0.61	- 1.0	0.04	
2030	2.9	25.4	0.1	8.2	10.6	0.7	5.3	- 14.8	0.6	0.47	- 0.8	0.04	- 1.6
2031	3.9	26.6	0.1	7.0	9.1	0.6	3.2	- 17.4	0.5	0.28	- 0.9	0.03	
2032	4.1	25.7	0.1	5.8	7.6	0.5	1.7	- 18.1	0.4	0.15	- 1.0	0.03	
2033	3.4	23.6	0.1	4.6	6.2	0.5	1.3	- 17.5	0.3	0.11	- 0.9	0.02	
2034	2.6	22.1	0.1	3.4	4.7	0.4	0.8	- 17.5	0.3	0.07	- 0.9	0.02	
2035	2.0	20.7	0.1	2.3	3.2	0.3	0.3	- 17.5	0.2	0.02	- 0.9	0.01	- 3.9

1. Based on Concept Consulting modelling results of annual amounts (averaged across 43 "weather years" for 2028 and 2035 only; Extended to other years by MBIE.
2. The assumed emissions factor for coal, gas and diesel are 0.089tCO_2/GJ, 0.053tCO_2/GJ and 0.070 tCO_2/GJ respectively.

Caveats

As noted above, the latest domestic natural gas production outlook indicates faster-than-expected declines in gas production – ie faster than expected when the ERP2 baseline was set (which used the supply outlook as at 1 January 2024).

This implies the table above likely overstates the expected reduction in emissions directly caused by having LNG available to cover dry-year risk. That is because the ERP2 baseline likely overstates the amount of domestic gas available for electricity generation. Therefore, while it is correct to say that emissions are expected to be 1.6 and 3.9 Mt lower than the baseline in EB2 and EB3 respectively, not all of this reduction can be attributed to the existence of LNG. A large portion of the estimated reduction can be attributed to the revisions in gas supply outlook and the underlying baseline rather than the policy of LNG importation. Hence, the results provided in the main body provide a better estimate of the emissions impacts of the LNG policy.