Gas Market Settings Investigation

Consultation Paper

SUBMISSIONS CLOSE: 4:00PM, THURSDAY 24 JUNE 2021

GAS INDUSTRY COMPANY LIMITED

Executive Summary

Introduction

The Minister of Energy & Resources has asked Gas Industry Company (in her letter, copied at the end of this Executive Summary) for advice on gas supply in the context of New Zealand's path to a net zero emissions economy by 2050 and the Government's commitment to transition to 100% renewable electricity by 2030. The Minister noted that she wants to ensure that current market, commercial and regulatory settings that provide for gas availability and flexibility are fit for purpose in supporting the transition.

To inform its advice to the Minister, Gas Industry Company is investigating the current market, commercial and regulatory settings in the natural gas market with a view to advising how these:

- affect overall availability and flexibility of gas supply
- support security of supply in the electricity market
- provide major gas users with sufficient certainty/transparency about gas supply for their operations,

and whether they are fit for purpose for the transition.

This investigation is one of a number of significant pieces of policy work underway relating to New Zealand's energy and emissions transition. It is to be expected that the policy landscape is uncertain in a time of rapid change and transition, and Gas Industry Company intends that this investigation will play a part in helping identify what steps could be taken to improve predictability and smooth the transition, while respecting commercial processes.

Over the last three months, Gas Industry Company has visited and had conversations with a wide range of stakeholders from across the gas and electricity industries, including producers, pipeline owners, gas shippers, electricity generators, major and medium sized industrial gas users, industry bodies and regulators to seek their views. We have learned a lot from those conversations and are grateful for the constructive engagement and thoughtful input.

We have also commissioned supporting analysis on the gas supply and demand outlook, the commercial and investment framework to meet gas demand over the next 15 years, and how gas storage and liquefied natural gas (LNG) could support / complement natural gas supply to provide the required gas availability and flexibility during the transition period.

This Consultation Paper reflects what we have heard and seeks your views on whether we have understood the settings and issues correctly and if we have missed anything. It is also an opportunity for you to provide your recommendations about what needs to happen next to ensure the gas industry can play its part in supporting the transition.

High-level views on whether the settings are fit for purpose

The vast majority of those we heard from concluded that the market, commercial and regulatory settings for gas for the most part work well and are manageable. Given New Zealand's lack of physical international connection or imported gas, the strongly held view was that there was no obvious better structure. Virtually all were concerned that intervention in commercial arrangements would reduce predictability and lead to poorer outcomes both for the gas and electricity industries and for New Zealand industry and business more generally.

There was universal acknowledgment that the current supply situation meant that some users did not have sufficient certainty about gas supply for their operations, and that tight market situations may well occur into the future given the transition. However, almost everyone considered that:

- the industry is doing all it can to fix the short-term supply problems, which is evidence of the system working
- the supply/demand balance will improve; this year's tight supply situation is due to an unusual set of circumstances, and may perhaps extend for up to around 18 months
- the industry-led commercial model will naturally develop to suit the conditions as it has previously (e.g. with standard commercial supply contract terms changing over time to provide for no new take or pay provisions, or improving buyers' ability to on-sell gas).

In terms of the industry's ability to support security of supply during the transition – both for electricity generation and for industry – it is clear that without significant investment in the upstream, the gas reserves and contingent resources in existing fields will not come to market and security of supply will be compromised. There are likely to be steps that can be taken to improve the investment climate so that the required investment is more likely to happen.

Gas supply and demand outlook

The tight supply conditions being experienced this year appear likely to continue into 2022 and this is expected to contribute to high wholesale gas prices. There is a possibility that this will be avoided if remedial work at the Pohokura field can be undertaken over the coming summer. However, the timing of this work is uncertain and there is no guarantee it will be successful.

There is more confidence that tight conditions will ease by 2023-24. This reflects an expectation that planned work programmes at Kapuni, Kupe, Mangahewa, Maui, and Turangi will have been undertaken by then and this will see more gas being brought to market. In addition, committed new renewable electricity generation projects are expected to be on stream, reducing the thermal backup required. Together these are likely to lift supply available to other gas users by around 30-45 PJ per year by 2024. If the Tiwai smelter closes at the end of 2024, that will further reduce demand for gas to generate electricity.

Looking out further, we understand that there is sufficient gas 'in the ground' to meet mass market (residential, commercial and agricultural), industrial and electricity generation demand until at least 2035 (and likely significantly beyond), provided demand supports investment into producing it. Out to 2027, that production could be delivered from existing gas reserves but beyond then contingent resources would likely need to be developed to meet demand.

It is important to note that if petrochemical gas demand did decline substantially, that would reduce or remove a key funder of development and source of flexibility for the gas system. That would pose a challenge for other gas users including the electricity sector, which is expected to rely on the ready availability of flexible thermal fuel until at least 2030.

Without further investment, the worst-case scenario could see gas becoming unavailable to support electricity security of supply as early as 2026. However, provided petrochemical demand continues to support production investment and/or other major gas users are willing to enter into longer-term contracts, that time horizon would be pushed out to around 2033.

We expect gas supply will need to become increasingly flexible to meet security of supply needs during the transition, particularly to support the electricity market. Gas storage will play a key role in enabling this – both in terms of the existing Ahuroa storage facility being filled and available, and potentially with new storage coming online if and when it becomes commercially viable.

Commercial and financial implications

Gas demand and supply in the period from 2022 to 2035 will be strongly influenced by decisions that are yet to be made. On the supply side, producers will be making decisions about whether to commit capital to produce from existing reserves and to convert undeveloped but identified (i.e. contingent) gas resources into reserves. Similarly, major gas users will be making decisions on whether to commit capital expenditure to allow future use of gas in their facilities.

Whether gas is available for all users depends on producers' willingness to invest more capital in supply-side assets. This will be influenced by customers' willingness to enter into contracts needed to underpin investment, particularly petrochemical customers due to their size and demand profile.

While such contracting processes have occurred smoothly in the past, there are added challenges in the current environment. In particular, some policies are yet to be finalised (e.g. the Government's response to the Climate Change Commission's advice) and the timing and extent of the transition remain unpredictable. Gas sector participants may prefer to delay some decisions until the investment climate is clearer. This could have supply-side implications later in the decade depending on the scale of affected projects and associated lead times.

Current arrangements and potential issues

In our conversations with stakeholders over the last three months, a number of themes have emerged. From what we've heard, the most critical / urgent issues to resolve to enable gas to support the transition to 100% renewable electricity and to net zero carbon emissions by 2050 fall into four groupings:

- gas system arrangements, which get a mixed report card, with the main challenges reported as the ability to transition in the expected timeframes (or in some cases at all) and the impact of supply constraints on businesses' ability to operate efficiently
- the role of gas in supporting electricity security of supply, including in particular the need for more flexibility (in both supply and demand) to meet increasingly intermittent demand for gas at a time when gas supply is tighter
- a perceived lack of predictability across a range of dimensions for participants at every level of the industry to be able to plan and invest appropriately
- the impact of both gas and electricity prices on an orderly transition.

Potential actions / solutions for feedback

Stakeholders have raised a range of potential next steps and solutions to the issues, which we include here for your comment and feedback. Gas Industry Company has not yet assessed these and intends to consider them and respond after this consultation and receiving feedback. There is unlikely to be a single solution and our initial thinking sees potential in a set of solutions that can provide greater confidence to support the required investment in gas supply and flexibility. We have included the full suite of suggestions from stakeholders for feedback. These include:

- *determining whether the incentives (if any) and mechanisms required to develop additional gas storage are sufficient* or whether additional support is required to ensure an appropriate level of storage is available to support the flexibility of gas delivery needed during the transition. Potential mechanisms could range from payments to those who keep stored gas available to support security of supply (effectively a capacity payment, which could be achieved through contracting as one potential tool), to subsidies for development of storage. Government could also assess whether gas storage could provide an appropriate interim energy storage solution for dry years until renewable solutions are developed and operating

- *making more comprehensive and timely information available in relation to gas supply and demand*, so that expected imbalances can be more effectively dealt with ahead of time. New Zealand Petroleum and Minerals' information gathering and reporting function could be expanded to include demand side information and to operate on a more frequent schedule; or Gas Industry Company (which already collects demand-side data) could perform this function
- *considering how to ensure the major risks to secure gas supply and their impact are better understood*, including field or pipeline outages, earlier than expected field decline etc. This could potentially involve:
  - *disclosing and interpreting major risk information* (alongside supply and demand information as above, if implemented), potentially in the form of risk assessment similar in authority to electricity risk curves. This could assist businesses for which gas supply is a relatively small part of their overall operations to more readily factor those risks into account in their commercial decision making
  - *requiring certain gas industry participants to conduct stress tests along the lines of those in the electricity industry*, to allow participants to see how their gas supply position and costs could change if major risks eventuated, and to ensure appropriate scrutiny at governance level of the contracting positions the participants are taking
- *enabling and encouraging wider use of the Emissions Trading Scheme (ETS) tools*, including the use of the ETS as the main mechanism to encourage increasingly lower emissions activities. This would provide clarity about how abatement of emissions will be treated (e.g. if CO_2 is used, or captured and stored), provide economic predictability to investment decision makers, and credits would incentivise gas users to transition away from the lowest value use of carbon first
- *providing clarity about the boundaries of the ETS* to enable industry decision makers to better assess the viability of existing assets or proposed investments. This could include clarifying where policy outcomes are not expected to be achieved by the ETS and how alternative policy will be assessed
- *reconsidering the suitability of the price / quality path regulatory framework for gas pipelines* in an industry undergoing transformational change, where consumers have an interest in the maintenance of the network for security of supply
- *clarifying how 'green' gases (such as hydrogen and biofuels) will be treated* and how they will be supported (as specifically as possible). Possible examples include potential promotion by government, allowing for increasing blends over time (with natural gas supported to continue in decreasing proportions as alternatives develop), and supporting continued viability of the infrastructure (particularly pipelines) needed to deliver new gases
- *considering whether promotion of or support for long-term wholesale contracts is needed*, to assist the underpinning of supply while enabling shorter-term contracts for users, particularly where demand is unpredictable
- *increasing policy certainty*, particularly around the nature and timing of the transition to a low carbon future. Many stakeholders picked up on the Climate Change Commission's suggestion of a new New Zealand Energy Strategy, noting that it could potentially provide clear outlines of regulatory intervention and tools if developed within a year and with comprehensive input from the broader energy sector
- *reducing barriers to LNG imports* as an alternative source of gas if local supply cannot meet demand, or as a counterfactual providing an effective price cap. An example of a barrier could include resource consenting for an import terminal

- *considering whether a reserves / capacity market for energy is desirable to ensure electricity security of supply*. If established, this could ensure that fuel (including thermal fuel) was available when electricity supply was constrained. It would require some attention to who would operate the market and how it would operate, the detail of how the reserves / capacity would be purchased and the conditions under which they would be released to market
- *considering whether government investment is needed to ensure security of supply* if thermal generation to support security of supply or gas supply to critical industry becomes less commercially viable during the transition, e.g. by transferring full or partial ownership of existing or new assets, or by becoming a buyer of last resort for gas production, flexibility (storage or pipelines), or electricity generation outputs.

Next steps

Following this consultation and review of submissions, we will develop advice for the Minister setting out current arrangements and our view as to whether they are fit for purpose, identifying current and potential issues, and proposing a work programme to help ensure the gas industry can play its part in New Zealand's energy transition.

Submissions

Written submissions on this Consultation Paper should be provided to Gas Industry Company by **4pm on Thursday 24 June 2021**. Submissions can be made by logging into Gas Industry Company's website and uploading your submission. If you cannot upload your submission, you can either email it to consultations@gasindustry.co.nz with "Submission - Gas Market Settings Investigation" in the subject line.

Submissions may be amended at any time before the closing date.

We intend to publish submissions without commercially sensitive information; if you include sensitive information that you do not wish to be published, please:

- indicate which part of your submission should not be published and explain why
- provide a version of your submission that we can publish ('publication version') alongside your complete submission marked 'confidential'.

Gas Industry Company is happy to meet or have a conversation with any stakeholder who wishes to discuss any aspect of this investigation or any issues in more detail, or would prefer to share confidential / sensitive information this way. Please contact carolyn.vanleuven@gasindustry.co.nz if you would like to arrange a discussion.

The Minister's letter

Hon Dr Megan Woods

MP for Wigram

Minister of Housing
Minister of Energy and Resources
Minister of Research, Science and Innovation
Associate Minister of Finance

Andrew Knight
Chief Executive
Gas Industry Company

Via email: Andrew.Knight@gasindustry.co.nz

Dear Andrew,

Thank you for the Gas Industry Company's recent briefing setting out key facts and issues affecting the gas industry. I am writing to you to raise a matter I would like you to report back on.

New Zealand has set a path for a net zero emissions economy. Under the Climate Change Response (Zero Carbon) Amendment Act 2019, Government has a legislated target of net zero greenhouse gas emissions (other than biogenic methane) by 2050. New Zealand also has a 2030 target under the Paris Agreement to reduce emissions by 30 per cent below 2005 emissions.

This Government is also committed to achieving 100 per cent renewable electricity by 2030. Decarbonisation will require the New Zealand's electricity system to transition away from non-renewable sources. I want to ensure that current market, commercial, and regulatory settings that provide for gas availability and flexibility are fit-for-purpose in supporting this transition.

In particular, I would like you to investigate the current settings in the natural gas market around contractual arrangements, including tendering processes, and how these affect overall availability and flexibility of gas supply. I am particularly interested in:

- How current market, commercial, and regulatory settings in the gas market support security of supply in the electricity market (particularly during periods of heightened demand), and whether these are fit-for-purpose for ensuring that thermal generation is provided during the transition

- How current market, commercial, and regulatory settings provide major gas users with sufficient certainty/transparency about gas supply for their operations, and whether these are fit-for-purpose during the transition.

I would like you to report back to me on the above. This report back should set out the current arrangements, identify any potential issues, and a proposed work programme to address any potential issues. I wish for you to report back to me by the middle of 2021.

I would appreciate if you could please keep MBIE official informed as your work progresses.

Private Bag 18041, Parliament Buildings, Wellington 6160, New Zealand
+64 4 817 8705 | m.woods@ministers.govt.nz | beehive.govt.nz

Should you wish to discuss this issue further, or have any questions, please get in touch with my MBIE officials in the first instance.

Yours Sincerely,

Hon Dr Megan Woods

Minister of Energy and Resources
18 December 2020

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1. Introduction

1.1 Background

The Minister of Energy & Resources wrote to Gas Industry Company on 18 December 2020[1] requesting advice on gas supply in the context of New Zealand's path to a net zero greenhouse gas emissions (apart from biogenic methane) (**Net Zero Emissions**) economy by 2050 and the Government's commitment to transition to 100% renewable electricity by 2030. The Minister noted that she wants to ensure that current market, commercial and regulatory settings that provide for gas availability and flexibility are fit for purpose in supporting the transition away from non-renewable sources for New Zealand's electricity system.

In particular, the Minister has asked Gas Industry Company to investigate the current market, commercial and regulatory settings in the natural gas market and to advise how these:

- affect overall availability and flexibility of gas supply
- support security of supply in the electricity market (particularly during periods of heightened demand) and whether they are fit for purpose to ensure that thermal generation is provided during the transition to 100% renewable electricity
- provide major gas users with sufficient certainty/transparency about gas supply for their operations.

The Minister has asked for a report back by the middle of 2021 setting out current arrangements, identifying any potential issues and proposing a work programme to address any issues identified.

This investigation is one of a number of significant pieces of work underway relating to New Zealand's energy and emissions transition. It sits alongside the Climate Change Commission's advice to the government; various Industry Transformation Plans; and a number of policy and legislative review workstreams including (among others) the Ministry for the Environment's work towards a National Direction on industrial greenhouse gas emissions, the Ministry of Business, Innovation and Employment's work on the NZ Battery Project, the Crown Minerals Act review and Just Transitions in Taranaki, the Electricity Price Review, and a potential new Energy Strategy for New Zealand if the Climate Change Commission's draft recommendation is taken up.

It is to be expected that the policy landscape is uncertain in a time of rapid change and transition, and Gas Industry Company intends that this investigation will play a part, alongside other work, in helping identify what steps could be taken to improve predictability and smooth the transition, while respecting commercial processes.

1.2 Purpose

This Consultation Paper consolidates what we have heard from stakeholders and our supplementary analysis and seeks your views on whether we have understood the issues correctly, what you think about some potential solutions that have been raised, and what if

[1] A copy of the Minister's letter is included at page 6 above.

anything we have missed. We are also keen to hear any recommendations on what you think needs to be done next to ensure the transition can be managed appropriately.

Your input into this investigation will help ensure that useful, balanced information on the realities of how the natural gas sector works in New Zealand is available, along with advice on how it can play its part in the transition – including where there are points of real concern and, conversely, of confidence within the sector. This will be provided to government to be taken into account to enable best informed decisions to be made for the future.

1.3 The role of gas in New Zealand

Gas makes a large and important contribution to New Zealand's energy supply – as a direct fuel source, supporting electricity security of supply and providing energy choice for consumers.

In New Zealand, natural gas fuels electricity generation, industries including meat, dairy, timber processing, pulp and paper and steel manufacture, and it provides feedstock and process gas for petrochemical (methanol and ammonia/urea) production. Gas is also used in a wide range of commercial enterprises such as greenhouses, restaurants and hotels, in community amenities such as schools, hospitals and public swimming pools, and for space and water heating and cooking in businesses and homes.

With a contribution of 185 petajoules (PJ), gas accounted for 21 percent of New Zealand's total energy needs in 2019; twice as much as hydro (10%) and slightly less than geothermal (22%). Gas fuels around 13 percent of electricity generation and meets 14 percent of consumer energy use (47 percent of consumer energy comes from oil and 24 percent from electricity), 15 percent of commercial energy use and 31 percent of industrial energy use (electricity supplies 25 percent of industrial energy, with biofuels supplying 22 percent, coal 11 percent and oil 10 percent).

However, natural gas is both a fossil fuel and a greenhouse gas, albeit the cleanest burning of all fossil fuels. As with other fossil fuels, the New Zealand Government wants to transition away from it over the coming years. Globally, gas is being used as a transition option to a low carbon future. As New Zealand transitions, gas could have various roles including:

- supporting and complementing an increasingly renewable electricity sector
- continuing to provide energy-intensive industries with relatively low greenhouse gas emissions energy where renewable fuels are currently unavailable or impractical
- direct use where it is more efficient and/or has a lower carbon footprint than alternatives.

More information on how New Zealand's gas industry is structured, the statutory and regulatory framework for gas and where gas fuels electricity is included in the appendix.

Q1: Do you agree with our characterisation of the current role of gas in New Zealand?

1.4 A note about the current gas supply situation

This investigation relates to the energy transition in the medium to longer term rather than the particular set of challenging circumstances that exist at the moment with low hydro lake levels and inflows and restricted gas supply from the Pohokura field. However, we recognise that, if not actively managed, similar situations could potentially become more common during the transition.

Until recently, gas users have enjoyed the benefit of abundant and flexible supply and low gas prices. Since the early 2000s, however, supply has become more variable as a series of high-impact events have led to extended periods of over and under-supply and increasing unpredictability.

Most recently, the accelerated decline of New Zealand's largest gas field at Pohokura and lower than expected hydro inflows have produced gas and electricity supply shortages and consequently high wholesale energy prices (see section 4.4.1 for more on this). The extension of the Tiwai Point aluminium smelter's electricity supply contract (around 13% of New Zealand's electricity use) has also seen higher ongoing electricity demand than some expected. This in turn has increased demand for thermal generation (gas and coal) to supplement the decreased generation from hydro along with the missing electricity that might otherwise have been provided by earlier generation investment as well as by reduced load.

Since around 2018, New Zealand's gas supply has been unable to meet the full market demand and this has required an increasing demand-side response. By some distance, the single largest provider of that response has been Methanex, which has reduced load and closed plant, including laying off staff. Electricity generators have also reduced their volumes of contracted and expected gas supply. Some large industrial users with contracted gas have also experienced supply curtailments, while others that are nearing or at the end of their existing contract terms have found that gas suppliers are now pricing 1-3-year-term gas contracts based on wholesale electricity prices.

The long lead times in upstream development mean that the current gas market conditions are likely to prevail over the next 1-2 years until increased upstream investment, closure of plant that has become uneconomic and commissioning of new electricity generation projects can resolve the tight supply situation.

The petrochemical sector will continue to play a key role as:

- its baseload demand underpins upstream investment and thereby enables gas to be developed
- it is the only sector with a sufficiently significant level of demand to make a material difference if a demand response is needed.

Any decisions petrochemical producers make around investments will therefore have a material impact on future supply and demand.

2. What we've heard

"Information disclosure has improved recently."

"If gas supply doesn't become more secure and prices don't stop rising, we will need to keep operating our coal boilers for longer."

"The contractual base of the gas system works well – we can't think of a better model for NZ."

"Gas will only be able to confidently support electricity security of supply, even for the transition period, if predictability improves."

"Without the existing gas infrastructure we can't really consider biogas or hydrogen as a realistic future energy source."

"Producers will only be able to access capital to invest and bring gas to market if we know there is a demand for it so that we can make a return."

"We are transitioning but we need time. We could do much better for NZ both in the short and longer term if we had longer."

"We've had to defer investments that would significantly improve our emissions profile at the same time as contributing to government priorities around the environment and housing."

"There is no realistic alternative to gas for our business. Carbon neutral gases may work but they will take a bit more time to become viable. Electricity is not an option."

"With our efficient, modern equipment, we can use gas and not emit, but we don't get credit for it."

"As parties leave the market, we are worried that the ones left behind will have to cover a higher and higher proportion of infrastructure costs, which means the next participant will be more likely to leave and costs will increase further for the remainder."

"There is a real risk that industrials will stop operating in NZ rather than transition."

"Some users are operating really inefficiently because of the current energy shortage and that has broader implications for NZ's supply chain.

"There's only so much information we can provide. Not all the information people are seeking actually exists."

"If we knew what to expect and when, we could plan for it and get on with running our business."

"Gas storage is an enabler of renewable electricity generation."

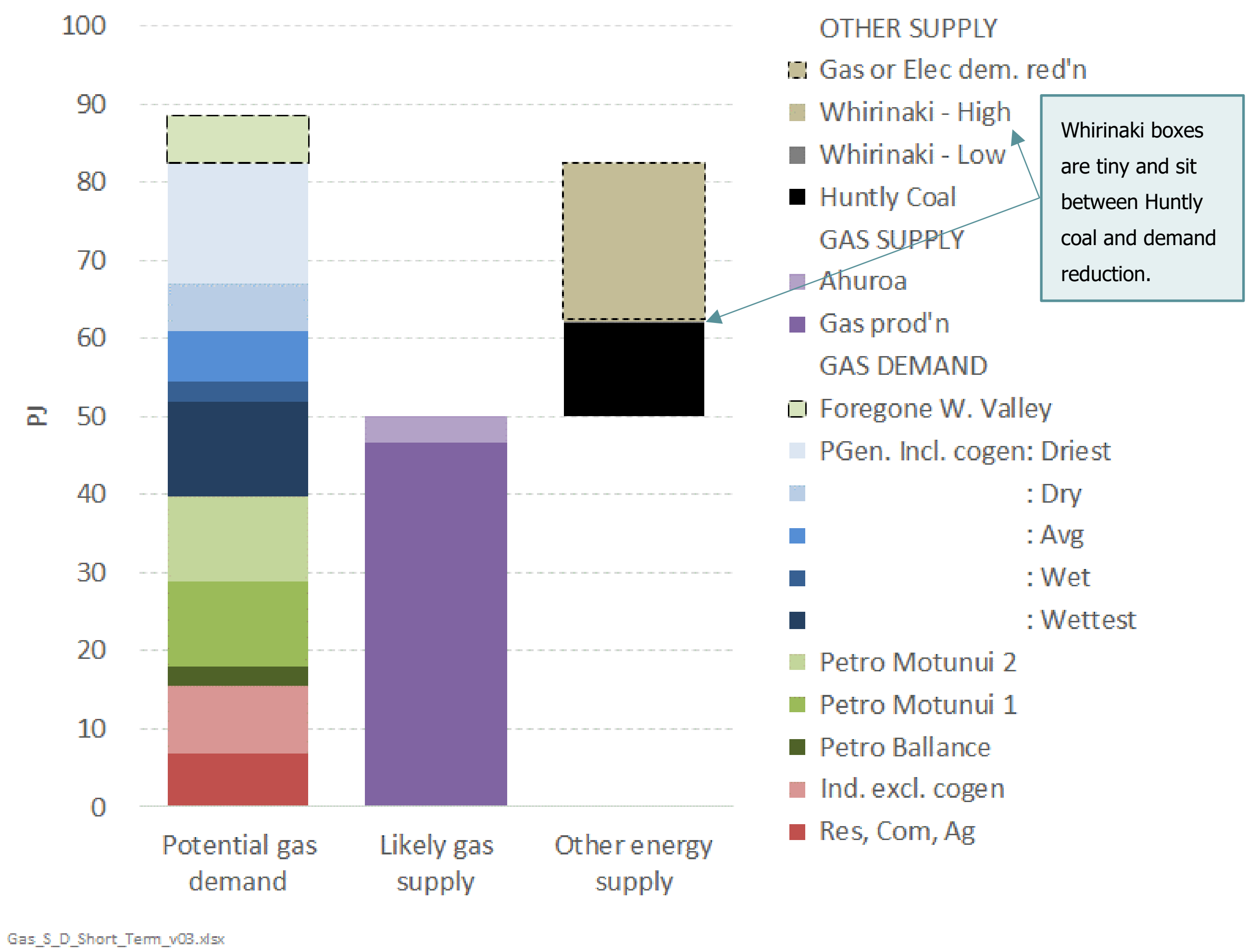
3. Outlook to 2030 and beyond

3.1 Gas supply and demand outlook

3.1.1 Forecast gas supply and demand in winter 2021

Gas supply for this year is tight, and the level of gas supply is unlikely to meet aggregate demand. This will be the case even if this winter turns out to be very wet and gas demand for power generation ("PGen" in Figure 1) is low. The size of the gap between supply and demand will increase if New Zealand experiences a dry winter, as shown in Figure 1 below.

Figure 1: Forecast gas supply and demand balance for June-Sept 2021



Source: Concept analysis

While the graph shows a gap between potential gas demand and expected supply, we do not expect this to compromise gas supply to mass market (residential, commercial and agricultural) users or electricity generators because:

- a significant amount of fuel for thermal generation can be provided by sources other than gas – principally coal-fired generation at Huntly, and diesel-fired generation at Whirinaki and Huntly

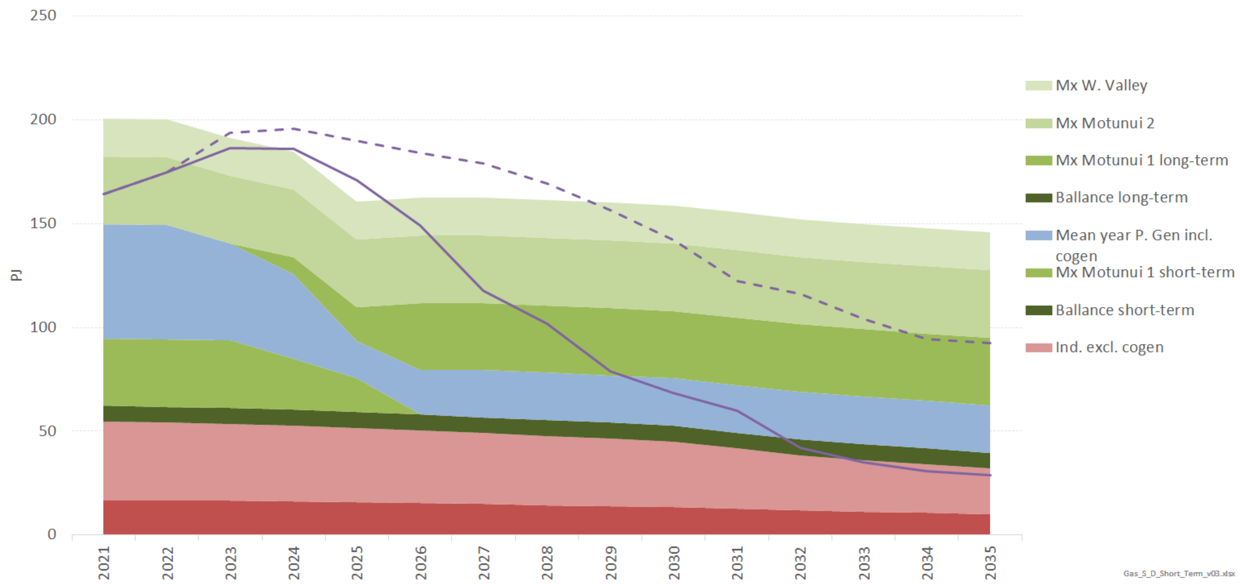
- there is the potential for some 'demand diversion', which could temporarily reduce gas and/or electricity demand and preserve supply for higher-value users. This could entail:
    - some gas users reducing demand and on-selling some of their entitlement to gas-fired electricity generation
    - some electricity consumers reducing demand, such as the recently announced agreement between Meridian and New Zealand Aluminium Smelters to reduce its electricity consumption at Tiwai Point by up to 30.5MW until the end of May.

The tight supply position is likely to contribute to very high wholesale gas prices – reflecting the price signal needed to induce demand diversion (such as the Waitara Valley methanol plant recently being mothballed).

3.1.2 Supply and demand forecast

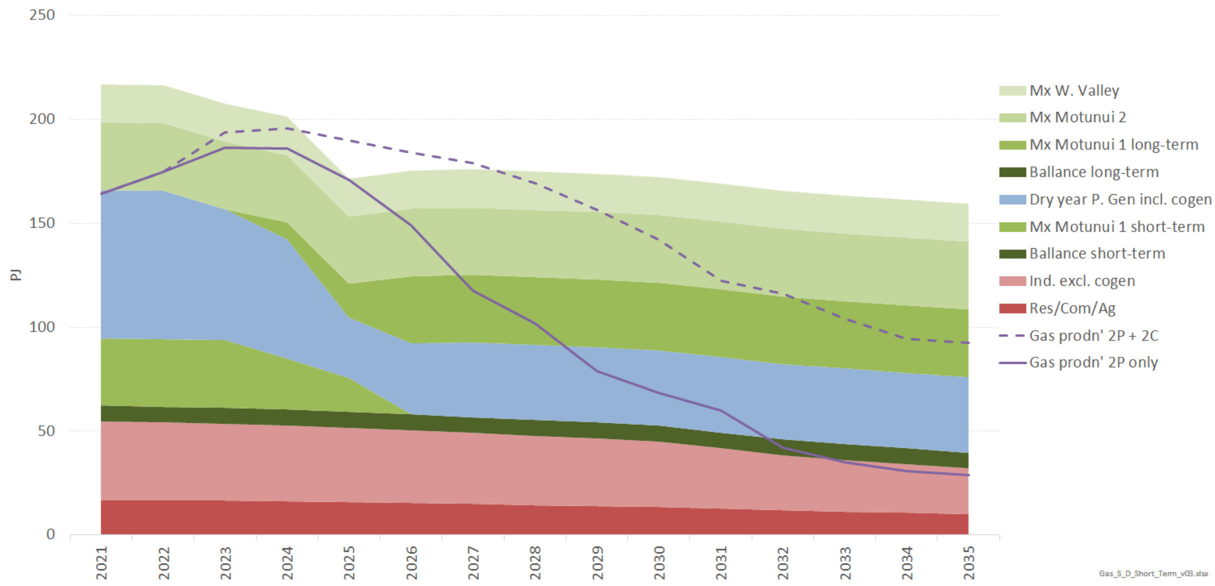
The solid line in Figure 2 below shows forecast gas supply based on current field deliverability and the remaining proven (2P) reserves that should come to market with currently expected investment. The upper dashed line in the graph reflects potential supply when including contingent (2C) resources that could be brought to market with further investment on top of what is planned. The coloured bands behind this supply curve reflect the composite of all gas demand, noting that the aggregate will be higher in a dry year (projected 1 in 10 years) or very dry year (based on around 1-in-50-year projections). Figure 3 shows the stack with dry (but not very dry) hydrology occurring across the forecast period.

Figure 2: Middle case demand and middle case supply



Source: Concept analysis

Figure 3: Middle case demand with consistent dry hydrology and middle case supply



Source: Concept analysis

Gas production cannot happen without significant ongoing investment. Even known reserves require continual investment to maintain field deliverability. The scale of this investment can differ depending on factors such as the nature of the field and success of work. From a technical perspective, natural gas resources in existing fields are generally becoming more costly to extract. This will require more investment and new technology over the coming decades and involve more project cost and risk to improve the rates of recovery from existing fields. Contingent (2C) resources have a higher risk profile than proven (2P) reserves, generally with an expected 50% success rate.

If investment does not happen at the levels needed to fill medium and longer-term gas demand as modelled by the Climate Change Commission, this is likely to lead to reduced levels of gas supply. This will mean that businesses with a lower willingness to pay may not be able to secure all of the gas they would like to at prices that support their ongoing business continuity.

As well as a large amount of investment, time is also needed to bring gas to market:

- A new onshore well drilled using an existing site and facilities requires 1-2 years to plan and start producing (assuming success). A similar new offshore well requires 5-10 years.
- It takes in the order of 2-4 years to bring new well sites, facilities and wells to production.
- Onshore exploration, appraisal and development requires a 5+ year timeframe in the current environment. Offshore this may take up to 10 years.

Upstream parties must have confidence that there will be demand to service in the future before they will be prepared to commit to investment happening today. Equally, new supply that will be coming to market over the next 2-3 years is a result of investment decisions that have occurred over previous years.

Forecast with investment only in proven (2P) reserves

The tight supply conditions being experienced this year appear likely to continue into 2022. There is a possibility this will be avoided if remedial work at the Pohokura field can be undertaken over the coming summer. However, the timing of this work is uncertain and there is no guarantee it will be successful.

There is more confidence that tight conditions will ease by 2023-24. This reflects an expectation that planned work programmes at Kapuni, Kupe, Mangahewa, Maui, and Turangi will have been undertaken by then and this will see more gas being brought to market. In addition, committed new renewable electricity generation projects are expected to be on stream, reducing the thermal backup generation required. Together these are likely to lift supply available to other gas users by around 30-45 PJ per year by 2024. If the Tiwai smelter closes at the end of 2024, that will further reduce demand for gas to generate electricity.

However, beyond around 2026, new supply would need to be developed from contingent (2C) resources to meet demand, depending on the rate at which demand recedes.

Forecast with additional investment in contingent (2C) resources

Looking out further, if contingent (2C) resources can be commercially developed, there would be sufficient gas to supply forecast demand, including significant levels of petrochemical production, out to 2035 (and likely significantly beyond), provided demand supports investment into producing it.

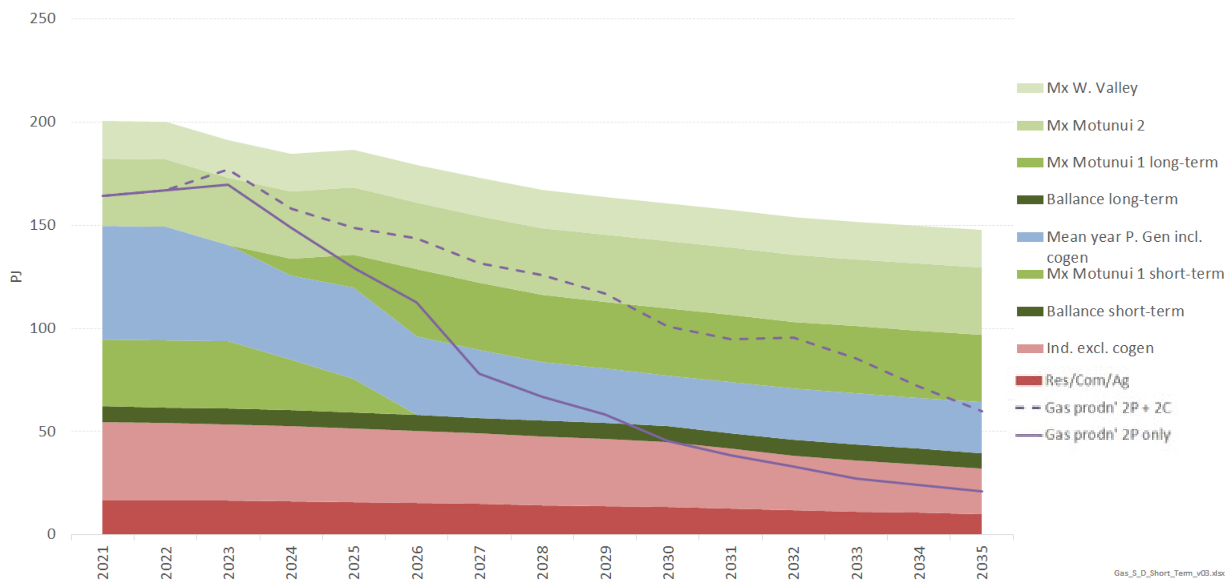
Analysis indicates that this includes sufficient headroom to support operation of 1-3 methanol units until at least 2030, even in a dry year, depending on the rate at which other gas demand recedes and how quickly contingent resources are developed.

It is important to note that if petrochemical gas demand did decline substantially, that would reduce or remove a key funder of development and source of swing (supply flexibility) for the gas system. That would pose a challenge for other gas users including the electricity sector, which is expected to rely on the ready availability of flexible thermal fuel until at least 2030.

Worst case forecast

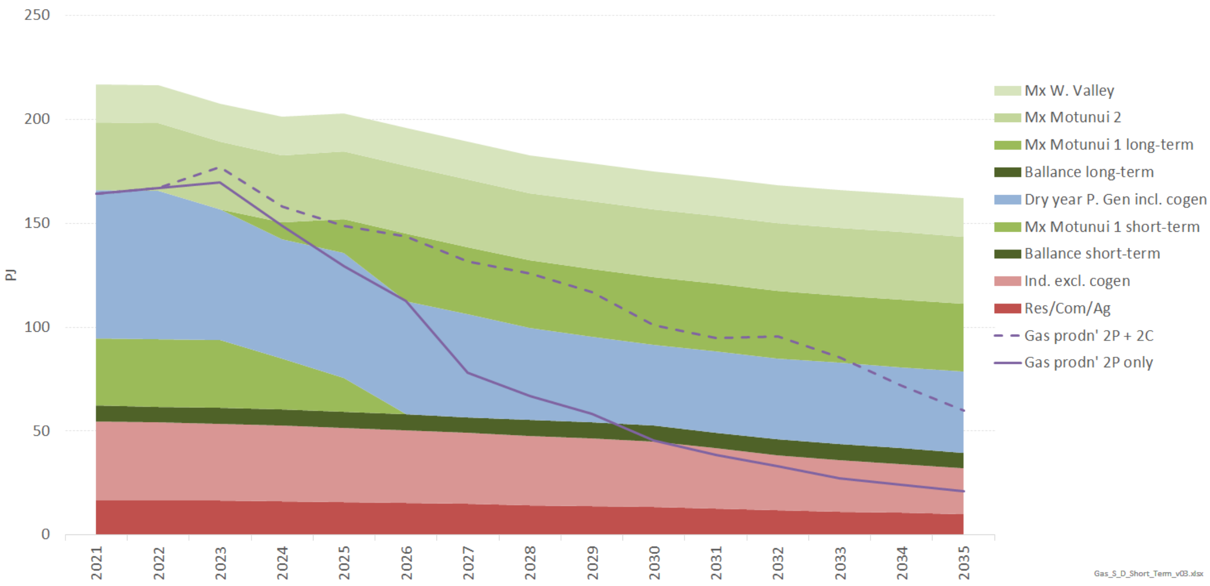
Figures 4 (with mean hydrology) and 5 (with consistent dry but not very dry hydrology) below demonstrate the outlook under the composite scenario with the tightest conditions, i.e. higher demand (including continued operation of the Tiwai Point aluminium smelter beyond 2024) and lower supply cases. Even under this 'stress' case, gas supply from 2P reserves would be sufficient to satisfy all demand for mass market, power generation and some petrochemical production (including at least one Motunui methanol train except in a dry year) until 2025. The development of contingent resources would extend this horizon to around 2029, but is unlikely to occur without commercial underpinning by petrochemical demand. This scenario could see gas becoming unavailable to support electricity security of supply as early as 2027, or winter 2026 with consistently dry (but not very dry) hydrology.

Figure 4: Composite – the stress test scenario (with mean hydrology)



Source: Concept analysis

Figure 5: Composite – the stress test scenario with consistent dry hydrology



Source: Concept analysis

Q2: Do you have any comments in relation to the gas supply and demand outlook?

3.2 Commercial outlook

Gas demand and supply in the period from 2022 to 2035 will be strongly influenced by decisions that are yet to be made. On the supply side, producers will be making decisions about whether to commit capital to produce from existing reserves and to convert undeveloped but identified (contingent) gas resources into reserves. Similarly, major gas users will be making decisions on whether to commit capital expenditure to allow future use of gas in their facilities.

Whether gas is available for all users depends on producers' willingness to invest more capital in supply-side assets. This will be influenced by customers' willingness to enter into contracts needed to underpin investment, particularly petrochemical customers due to their size and demand profile.

While such contracting processes have occurred smoothly in the past, there are added challenges in the current environment. In particular, some policies (e.g. the Government's response to the Climate Change Commission's advice due at the end of this month) are yet to be finalised and the timing and extent of the transition remain unpredictable. Gas sector participants may prefer to delay some decisions until the investment climate is clearer. This could have supply-side implications later in the decade depending on the scale of affected projects and associated lead times.

3.2.1 Investment in gas supply

Delivering new investment in long-lived gas production infrastructure can be commercially challenging in a market in which demand is declining and the rate of this decline is unpredictable. It is more often the case that new investment in gas production assets has been undertaken on the expectation of growing (or stable) demand providing a degree of certainty about the long-term economics of the project.

The difficulties with investing in markets with unpredictable future demand are two-fold:

- Owners of long-lived assets will need to recover their capital costs over time and therefore rely on demand persisting in future to support their continued ability to recover their costs. If demand does not persist, then it is likely that some portion of the capital costs will not be recovered.

- In capital intensive industries, short-run marginal costs are often low. During periods of excess supply (for instance, because demand has fallen more quickly than expected), this can mean that prices can be very low, which in turn can also create the risk that capital costs will not be recovered.

This unpredictability about the rate of decline in gas demand and its implication for utilisation and break even gas prices for new infrastructure means that the need for investors in new gas infrastructure to manage their risk through long-term contracts is likely to become much more acute in a market with declining demand. We understand that producers and their funders would generally be looking for a 10-year return on investment, with commensurately higher prices being required to support shorter terms.

For some gas users, entering into a long-term gas supply agreement to support new investment may be no issue. Some customers – particularly larger industrial customers – are accustomed to long-term contracting (even preferring the certainty that long-term contracts provide) and will be sufficiently certain about their future operations that a long-term contract is commercial. We understand that many users are used to operating on around a 2-3-year contracting cycle, however, so longer terms require a change in approach.

For some (particularly commercial and residential customers or their retailers), the risks of entering into a long-term gas supply agreement may be problematic. In a growing or stable market retailers may be able to manage the risk of entering into a long-term contract, confident that they will either be able to attract and maintain sufficient customers to justify the commitment, or, in the worst case, on-sell the gas to another retailer or gas user. But in a market in which demand is declining at an unpredictable rate, a retailer faces substantially more risk in doing so.

We heard from a number of large users that they would be willing to enter into longer-term contracts of up to around 5 years, but that 10 years was likely to be too long in the current unpredictable climate.

3.2.2 Transmission and distribution

The price of gas transmission and distribution will also need to increase in order for pipeline owners to continue to maintain the current return on their asset base. This is discussed further in section 4.4.2.

This increase in tariffs would likely result in an increase in customers choosing to switch away from gas, or to otherwise reduce their gas consumption (or even to cease operations), requiring further increases in required tariffs for remaining customers.

Eventually, when insufficient users remain who are prepared to pay for pipeline assets to be maintained, it may become uneconomic to use them at all.

However, the existing gas transmission and distribution infrastructure will be a critical component to supplying reticulated 'green' gases in future – which will improve their affordability and avoid truck movements, providing a safer and more environmentally friendly method of transporting low carbon energy. There are a number of workstreams underway that would see increasing proportions of hydrogen and/or biogas blended with natural gas, with a view to displacing natural gas in New Zealand over time. See section 5.6 for more on 'green' gases.

3.2.3 Implications for gas deliverability to generators

In response to the Government's goal of 100% renewable electricity generation for New Zealand in a normal hydrological year, generators are exposed to the unique risk that they will be expected to operate their gas-fired plant less and less frequently, potentially only every few months and after 2030 only every few years on average – and without any realistic ability to predict which years that will be or how much thermal generation they will need to provide in any given year.

This poses significant commercial issues, given the substantial fixed costs of maintaining both the generating plant itself and the infrastructure required to deliver gas to it. While inter-participant contracting is a fairly common mechanism to cover fixed costs of reserve generation, some stakeholders raised concerns about the scale of cost required to provide this service when compared to the likelihood of a dry year event.

The break-even prices that generators or contracted parties would require to recover these costs (either on the spot market or in their contracts) will likely be many magnitudes higher for longer than have been experienced in New Zealand historically, and extremely unpredictable.

In these circumstances, it seems unlikely that gas-powered generators would be prepared to invest in securing the required gas deliverability and maintaining the availability of gas-fired generating plant beyond 2030 without some greater revenue certainty.

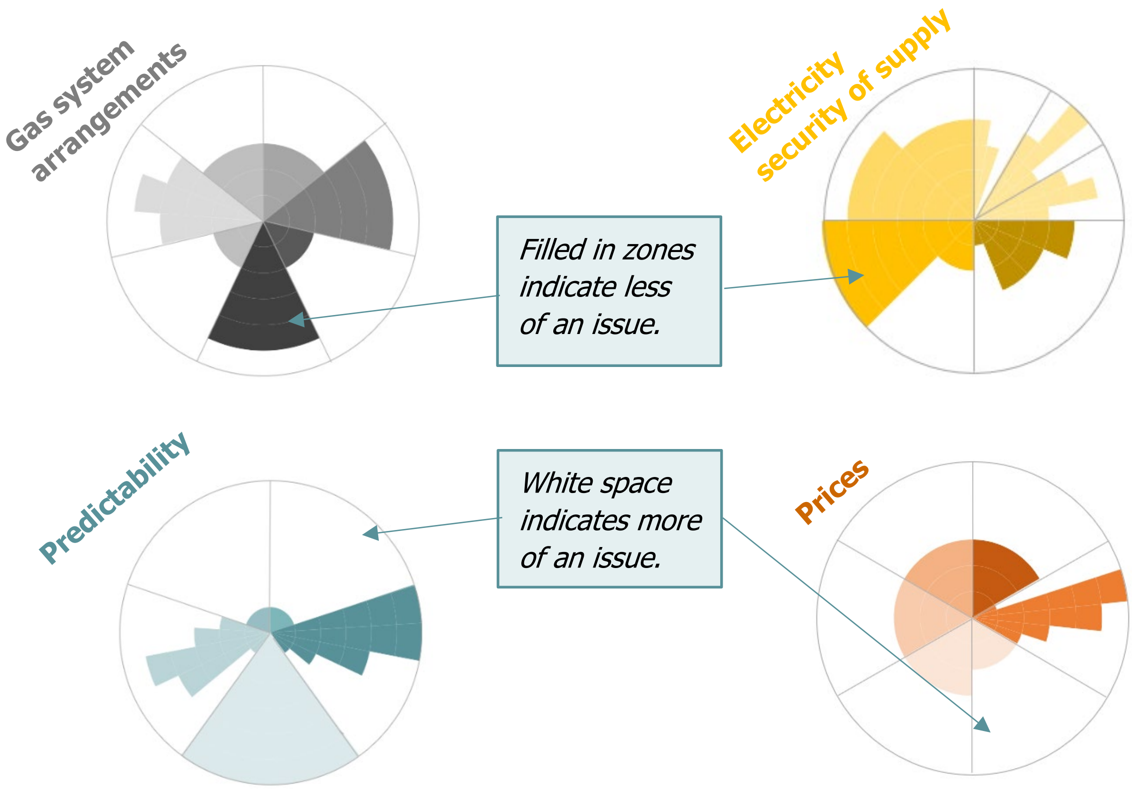
Q3: Do you agree with our characterisation of the commercial outlook for gas?

4. Current arrangements and potential issues

In our conversations with stakeholders over the last three months, a number of themes have emerged. From what we heard, the most critical / urgent issues to resolve in order to enable gas to support the transition to 100% renewable electricity by 2030 and to Net Zero Emissions by 2050 fall into four groupings:

- gas system arrangements, including in particular transition and efficiency issues
- the role of gas in supporting electricity security of supply, including in particular the increasing need for flexibility (at both supply and demand levels)
- a perceived lack of predictability across a range of dimensions for participants at every level of the industry to be able to plan and invest appropriately
- the impact of both gas and electricity prices on an orderly transition

We have included images at the start of each group of issues (and indicative versions below) illustrating the significance of various components of each theme. The white space in these images reflects the areas where feedback indicates there are gaps in the current system. For example, a zone that is completely filled in to the outer rings indicates that stakeholders are comfortable with current arrangements, while a zone with mostly white space shows they believe more work is required.

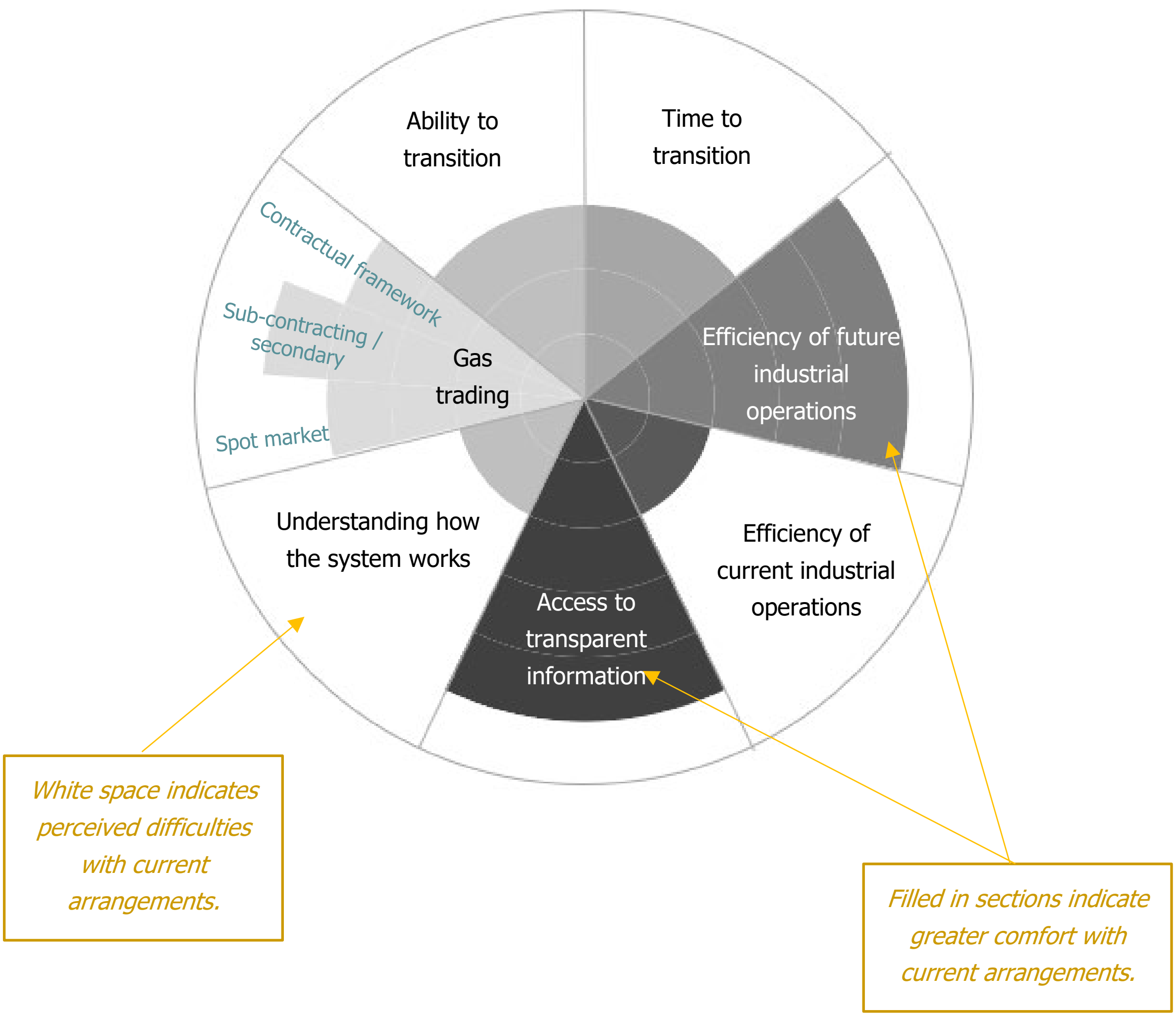


4.1 Gas system arrangements

A number of themes and issues raised relate to the operation of the gas system arrangements in New Zealand, including:

1. understanding of how the gas system works
2. access to transparent information
3. gas trading:
    a. contractual framework
    b. sub-contracting / informal arrangements
    c. spot market
    d. getting the gas to the user
    e. other trade-related issues
4. transition issues (ability and time to transition)
5. efficiency of industrial plant operations.

Figure 8: Gas system themes



4.1.1 Understanding of how the gas system works

One of the strongest themes that came through in our discussions with industry and those outside the industry was that levels of understanding of how New Zealand's natural gas system works are generally low. This risks decisions being made that will not have their intended effect, or that will have unintended consequences, compromising the gas industry's ability to support the energy transition.

One of the main reasons for this appears to be that, as a result of the abundant and flexible gas supply, low prices and largely smooth operation of the gas sector in the past, the need to more deeply understand it has fallen to a low priority for many participants of the various energy sectors in New Zealand. It was simply assumed that the sector would continue to operate as it had in the past, with surplus production capacity creating a buffer, few major events to threaten the operation of businesses, and mechanisms such as the CCM Regulations and clauses within bilateral contracts ensuring that any event has generally been quickly resolved following an established and understood process.

As noted above, gas supply and demand are tighter than in the past and the industry is now at the start of a transition which will bring changes to the existing system. With this transition comes increased risk. We heard many comments about the importance of participants in the gas industry, as well as in associated industries such as electricity, ensuring that they have sufficient understanding of how the gas system works so that they can make informed decisions to better mitigate any risks for their businesses.

4.1.2 Access to transparent information

Several stakeholders provided views on the level of information disclosure in the gas industry. Some were concerned about the level of visibility of upstream information in particular. However, most commented that this has significantly improved recently and many commended OMV for its disclosures in relation to the recent issues at Pohokura.

Information disclosure workstream

The adequacy of information disclosure in the gas industry has been considered as part of a dedicated workstream led by Gas Industry Company, which assessed current levels of information disclosure in relation to the following information areas:

1. gas production and related processing facility outage information (including planned and unplanned outages)
2. gas storage facility outage information (including planned and unplanned outages)
3. gas positions of thermal electricity generators
4. gas contract price and volume information
5. major user facility outage information (including planned and unplanned outages)
6. transmission pipeline outage information (including planned and unplanned outages)
7. emsTradepoint traded volumes and prices information
8. the quantity of stored gas and available storage capacity
9. forecasts of gas production
10. forecasts of major users' consumption.

Proposed legislative amendments

The Government has proposed amendments to the Gas Act to enhance regulation-making powers in relation to information disclosure and to ensure that settings around enforcement and penalties are suitably robust. The Gas (Information Disclosure and Penalties) Amendment Bill is at second reading stage, and once passed into law will enable regulations to be made.

Gas Industry Company recently consulted on a draft statement of proposal relating to information disclosure arrangements for *gas production* and *gas storage outage information* (items 1 and 2 above). The proposal was that the most practicable means for implementing those arrangements would be within a framework of regulations (and/or rules) under the Gas Act. If this initial view is reflected in Gas Industry Company's final statement of proposal and the Bill is passed, Gas Industry Company will be able to make a recommendation to the Minister for regulations.

Thermal fuel disclosures

The Electricity Authority, with support from Gas Industry Company, took up the issue of whether further information was needed in relation to the *gas positions of thermal electricity generators* (item 3 above) in its Wholesale Market Information Disclosure project in 2020[2]. The Authority has recently amended the Electricity Industry Participation Code 2010 to improve the availability of thermal fuel information. The Code amendments require the approximately 30 "major participants" to report on how they are meeting their disclosure obligations under the Code, and guidelines have been updated to clarify the application of the disclosure regime under the Code to the availability of thermal fuel.

Further work underway

As part of Gas Industry Company's information disclosure workstream:

- further work is underway on whether additional information disclosure is required in relation to *contract price and volumes* and/or *major user outages* (items 4 and 5 above)
- it was determined that further consideration of information disclosure in relation to items 6 to 10 above was not needed[3].

Finding relevant information

Through the information disclosure work and our discussions with industry participants, it has become clear that some parties (particularly those who do not participate regularly in the gas wholesale market) may be unaware of some information that is publicly available; and that they may also have difficulty in interpreting this information.

Gas Industry Company intends to develop an information portal on its website, which will be a one-stop launch-place for parties to access publicly available information. The portal will include a guide to assist in the interpretation of this information. Information now available in graph form on Gas Industry Company's website is the first step in the development of the portal[4].

In addition, the Electricity Authority has added links to thermal fuel data to its Electricity Market Information (EMI) website[5].

We also note that many participants (or industry groupings they are members of) access information through consultancies who interpret market data for them.

4.1.3 Gas trading

Contractual framework

Wholesale gas trading in New Zealand has traditionally been arranged through private bilateral contracts between producers on the one side and wholesalers or direct users on the other.

[2] See https://www.ea.govt.nz/development/work-programme/risk-management/wholesale-market-information-disclosure/ for more detail.

[3] A detailed discussion of each information area is available in the Problem Assessment (https://www.gasindustry.co.nz/work-programmes/gas-sector-information-disclosure/problem-assessment-october-2019/document/6634).

[4] See https://www.gasindustry.co.nz/about-the-industry/gas-industry-information-portal/gas-production-and-major-consumption-charts/

[5] See https://www.emi.ea.govt.nz/Wholesale/InformationDisclosure.

In the primary wholesale market, the contractual framework reflects the large investments made by producers and counterparty buyers, such as electricity generators and petrochemical producers, and serves to cover the field development risks and financial positions of the parties.

We heard strong views that participants could not think of any other mechanism that would be able to adequately do this in a small market like New Zealand, and that the contractual base of the gas system generally works well.

Upstream, producers are required to apply (and pay a $1,000 application fee) for Ministerial consent to "deal" with their permits, which includes selling the gas they produce in an arrangement that lasts for more than 12 months[6]. One stakeholder mentioned this requirement leading to only large-scale contracts with producers. However, given easy access to wholesalers and brokers (see below), we did not hear any reports of the requirement disincentivising smaller-scale contracts with producers.

Users who do not meet their gas supply requirements through direct contracts with producers can purchase through gas wholesalers. In general, the larger the demand, the longer term the user needs to factor in when acquiring gas.

We understand that gas wholesalers in New Zealand now generally purchase gas only to meet a known demand and sell to gas users only when they have a known supply. This means that there is limited ability to meet the needs of users with shorter contracting timeframes unless new supply comes on stream.

We heard that major gas users who value security of supply contract on various bases to ensure they have access to the gas they need, which may include:

- a portfolio of supply from several fields to ensure deliverability risk is not tied to a single field
- longer-term supply agreements providing for a greater certainty of demand
- exclusive arrangements in some cases, which are likely to enable a user to achieve higher priority status with a supplier and thus more certainty of gas supply, especially during periods of supply constraint
- non-exclusive arrangements if the seller cannot meet the buyer's entire natural gas needs
- interruptible supply arrangements in some cases where users' businesses can accommodate them, enabling the seller to redirect gas to alternative users in periods of reduced gas supply
- call arrangements to enable the user to call for a pre-agreed volume from the seller, requiring the seller to reserve some capacity to meet its obligation.

Some major users were concerned that the low number of supply sources and sellers and the firm commitment of production to longer-term customers (including those who had the ability to store excess gas for use at a later date) limited their prospects of contracting the gas they needed to run their operations. For example, we heard concern that the entire expected production over the coming years from new onshore wells to be drilled in 2022 is already committed to contracts.

In addition, concern was expressed that suppliers' ability under contract to curtail supply could have a significant impact on gas users' ability to carry on their business. Historically this has been relatively easy for users to deal with, given the ability to source gas from alternative sources where needed. In the current climate, however, given tighter supply and more limited flexibility, this can have a much more significant impact on gas users' ability to carry on their business.

While long-term commitments are desirable for some users with known ongoing demand, many large users have tended to contract for 2-3 years at a time, confident that they will be able to

[6] See section 41B Crown Minerals Act 1991.

secure their next tranche of gas towards the end of that period (generally booking gas in the 6 months to a year before the new tranche begins).

However, this is changing in the current climate and users are looking to book their gas supplies:

- much earlier (e.g. starting discussions now to arrange supply from 2023)
- for a longer period (although the approximately 10-year timeframe required to support new production investment is too long for most given current business uncertainties; and some indicated a 5-year timeframe would be more feasible).

Sub-contracting / informal arrangements

Despite contractual restrictions to on-selling gas (which several stakeholders mentioned as an issue), informal short-term trading and gas swaps have long taken place, including with gas buyers wanting to manage take-or-pay exposures under their long-term contracts (less common now), and producers seeking an outlet for smaller parcels of gas from new discoveries.

Many examples of these practices have been observed this year in response to tight gas supply as they are a key mechanism for dealing with constrained deliverability. Examples include:

- a gas user with a planned outage swapping out their allocated gas for that month to another period so that another user who had insufficient gas supply could use it – meaning issues with deliverability were managed
- a tolling arrangement between two electricity generators, where one on-sold their gas to another more efficient plant so more GWh is produced per GJ of gas.

Trades arranged by gas brokers are becoming increasingly common, whereby sellers and buyers are joined directly or gas from a number of sources is aggregated to meet user demand.

A number of users were very positive about their use of brokers to meet their gas supply needs (albeit often at a higher gas price than they had hoped to pay!).

However, some participants wanted a greater ability to trade gas in this way and we would be keen to understand what barriers there may be, if any, to more of this happening.

Spot gas market

Since 2013, emsTradepoint has provided a commercial trading platform for balancing transactions and 'spot' gas, although only around 4% of trades occur on the platform.

This enables gas users to trade on the spot market to obtain gas if their primary contractual arrangements are insufficient or interrupted; or to shift gas entitlements over time to better match peak or seasonal requirements.

Some gas industry participants would prefer to see a greater proportion of gas being traded through emsTradepoint, thereby increasing the liquidity of the system and providing more transparency over prices. Conversely, those who had firm longer-term commitments in place were more comfortable with the certainty the traditional long-term bilateral contracting framework provides.

From the perspective of producers and some users with major infrastructure commitments, a greater reliance on the spot market would not meet their needs in terms of providing the required certainty to underpin development (and obtain capital to invest).

Getting the gas to the user

Some participants raised concerns with the way the gas transmission system works in that:

- the need for forward reservation to secure capacity on the pipeline in their view reduced flexibility in the system
- the need to organise shipping through the pipes alongside securing gas supply was an additional hurdle for some smaller trades and for on-selling gas (although this was less of an

issue given most smaller trades are arranged through retailers or brokers, who arrange both supply and shipping).

Both the Maui Pipeline Operating Code and the Vector Transmission Code have established change processes available to address issues regarding the transmission arrangements and provide a process for considering alternative proposals.

Other trade-related issues

In addition to the difficulty that some users may face in managing the risks of long-term contracting, we heard that there may be a free-riding problem – whereby all gas users (or their retailers) benefit from the decision by a smaller group of (larger) gas users to commit to long-term gas supply agreements sufficient to attract new investment. In this way, security of supply is effectively underpinned by a limited number of key buyers.

In these circumstances, gas users and retailers may have an incentive not to take the risk of entering into a long-term gas supply agreement, in the hope that some other gas users or retailers will do so.

The combination of the added risk of entering into a long-term gas supply agreement in a market with declining demand, and the incentive to free-ride on long-term contracting by others, may mean that socially beneficial new investments in gas production capacity do not occur.

4.1.4 Transition issues

We heard that users are universally looking at cleaner and more efficient options for running their businesses and have plans for transitioning to much lower carbon or net zero production. Many gas users we heard from had already successfully carried out parts of this transition, for example by switching over parts of their process to electricity and by improving efficiencies in their plant. However, most are not expecting to be in a position to be able to substitute away from natural gas before 2030 (or even beyond).

In many cases, this is because alternatives:

- are not suitable (e.g. they can't provide high enough heat; or even very short interruptions to electricity supply (a 'flicker' of under a second) could see their plant offline for days)
- are not available, or not available in sufficient quantities to meet expected timeframes without exponential growth in production (e.g. the number of new renewables-fuelled boilers needed to replace gas boilers for the dairy industry)
- simply cannot do what natural gas can for their processes and businesses, or would lead to considerably less efficient outcomes (e.g. horticultural businesses use the residual CO_2 from their gas heating to enable faster growth, rather than having to find and purchase another source of captured CO_2 to purchase).

Some large industrial gas users told us that if they knew they would be able to operate on gas until a later date (say 2040) while transitioning, they are confident they could develop carbon neutral processes and products and continue to support the New Zealand economy.

A number of gas users told us that a carefully planned and measured transition could directly enable significantly better outcomes for New Zealand, by:

- enabling continued use of New Zealand resources (including wood, farmed resources, minerals, and energy resources) to produce materials to support New Zealand industries
- ensuring critical industries (including building and construction) can operate in New Zealand at the scale and speed desired
- enabling better environmental outcomes, e.g. through more efficient water and land use
- retaining jobs
- reducing the need to import, sending money offshore and resulting in delays due to transport issues

- reducing global carbon emissions (e.g. because production in New Zealand is significantly lower emission than in other locations).

In some cases, even if a forced transition away from gas in a relatively short timeframe were achievable, it would compromise users' ability to move away from less efficient and higher emissions plant in other parts of their business. We heard that:

- some planned investments to replace elderly and inefficient coal boilers with efficient gas boilers and processes that use rather than emit by-products would only be able to proceed if the transition timeframe allowed for a return on investment
- too short a transition would slow the replacement of coal boilers in the dairy and horticultural industries.

4.1.5 Efficiency of industrial plant operations

When gas is constrained as it is currently, industries may not be able to operate optimally, which means there may be less efficient outcomes, including:

- reduced plant efficiency resulting in increased energy use per unit of product
- reduced production of materials required for other industrial businesses such as building and construction, given our integrated industrial sector
- potential job losses
- increasing reliance on imported product
- increased local emissions from reduced plant efficiency
- increased global emissions as international product from higher carbon sources must be imported to supplement local supply.

As the energy transition continues, stakeholders are concerned that periods of constrained supply (and associated poor outcomes such as those mentioned) may become more frequent, with flow on effects to the viability of industrial operations and New Zealand's vulnerability to international supply chains.

4.2 Gas support for electricity security of supply

In general, stakeholders considered that the current market, commercial and regulatory settings are largely fit for purpose to support security of supply in the electricity market during the transition, subject to concerns that a lack of predictability (see section 4.3) is undermining this.

However, in order for gas to effectively support security of supply in the electricity market, there is clearly a need for:

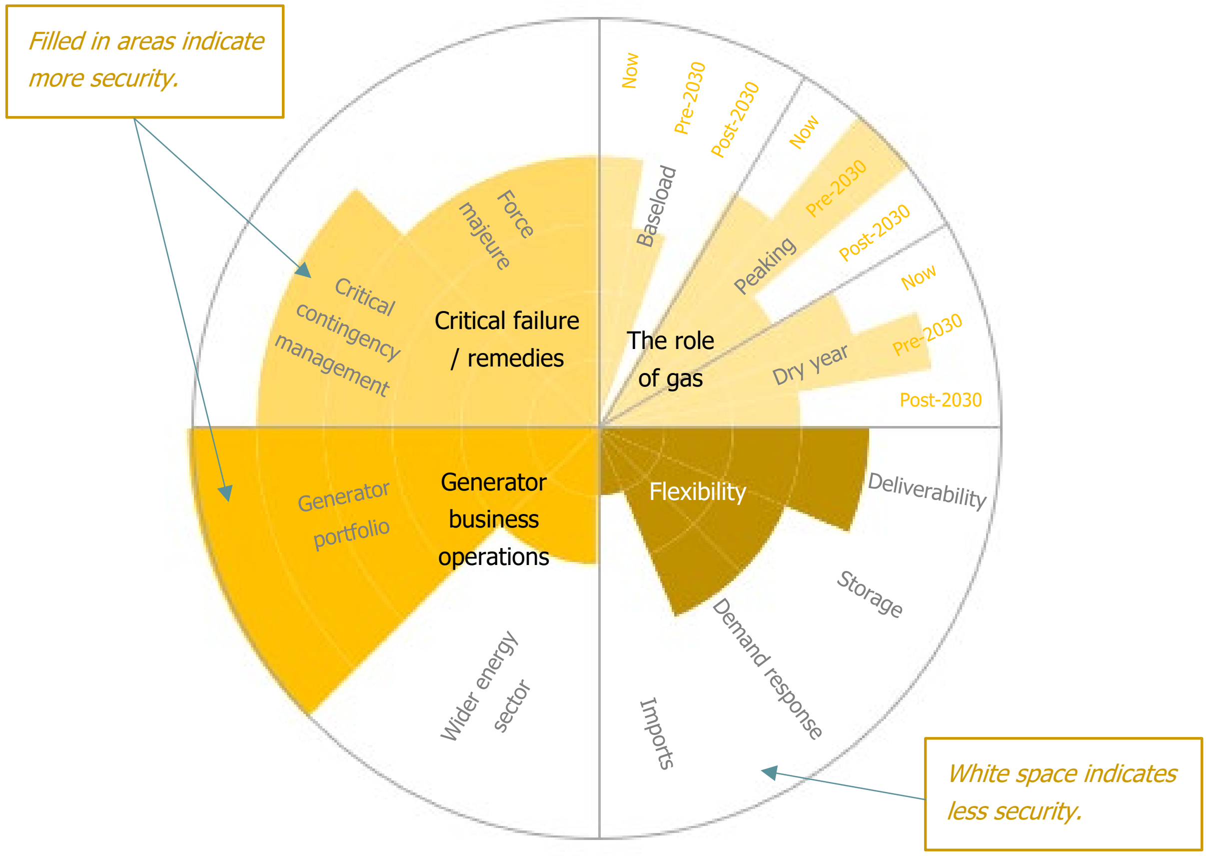
- continuing investment in upstream development and production
- investment in maintenance of thermal generation assets.

There was also a strong view that increasing flexibility would be needed as the transition progresses, which additional gas storage could potentially support; and some participants wanted better information to support their decision making (see section 4.1.2).

We have grouped issues relating to how gas supports electricity security of supply into four areas:

1. the role of gas (or thermal generation more broadly) in electricity generation
2. generator business operations
3. flexibility in gas supply to meet the electricity system's needs (on a peaking or seasonal basis), including:
   a. deliverability
   b. storage
   c. demand response
   d. imports
4. critical failure impact and remedies / responses.

Figure 7: Themes relating to electricity security of supply



4.2.1 The role of gas in electricity generation

Gas-fired generation has provided three functions in New Zealand's electricity market:

- baseload generation
- peaking generation
- dry year/seasonal cover.

Generators have flexibility and control over their gas-fired operations since gas can be contracted to provide a predictable level of flexibility and controllable supply, both in gas supply arrangements themselves and in contracted storage. This means that gas-fired generation complements other more variable energy sources such as wind and water.

Gas-fired generating plants typically operate to balance electricity supply and demand in both the short and the long term. In the short term, they respond to imminent increases in demand (evening peak demand), or sudden decreases in supply (wind generation dropping away as still/calm weather sets in). On a longer timeframe, they provide seasonal cover for increased demand through winter, and support hydro generation during and in the lead up to dry years to prevent future risk of water shortages.

Participants said that they fully expect the nature of these roles to change over the next 10-15 years as the electricity system moves to a higher proportion of renewable generation. New renewable generation will displace much of the baseload generation function of gas-fired generators. However, those we spoke with expected that the peaking and dry year/seasonal cover roles for gas-fired generation will continue to be required, and could even become greater as electricity demand increases and increasingly variable renewable generation requires more flexible support (depending on to what extent the flexibility of the demand side increases).

Currently, however, participants commented that there is little clarity about the role gas-fired generation will have as the electricity sector decarbonises. This feeds through to the supply side, with a lack of clarity of the scale of upstream investment required to support the unknown level of gas-fired generation over the transition.

Significant capital and time investment is needed to bring gas to market. Forecast gas supply and demand shows sufficient supply even in the worst case scenario to satisfy demand for electricity generation until 2026 (assuming gas demand for petrochemical production drops for some of this period). As long as investment (likely underpinned by longer-term petrochemical demand) is sufficient to support producers to bring contingent (2C) reserves to market on top of currently planned investment, then gas will be available to provide security of supply in the electricity market until around 2033 and potentially beyond.

As well as the need for ongoing upstream investment, the thermal generation assets themselves require upgrading and recertification from time to time. Such work requires significant capital expenditure and is only viable if the plant is expected to be operating for a reasonable period of time following that investment. It was noted that existing thermal generating plants may not be maintained or upgraded if the costs cannot be recovered through contracting and/or the spot market. If these assets are still required by the system but undervalued by the market, this could elevate electricity security of supply risk due to an increased risk of critical failure of poorly maintained plant. This risk would exist until an alternative backup for peaking and dry year/seasonal demand became operational.

4.2.2 Generator business operations

Several stakeholders expressed concern that the nature and structure of the current electricity sector means that individual generators are incentivised to primarily manage their security of supply risk for their own retail book, which may not necessarily be how the risk would be managed taking a wider sector view on security of supply.

However, there is trading between parties to partly deal with this, whereby parties that are long on flexibility will sell contracts to parties that are short on flexibility (albeit that this may largely be driven by individual companies' management of their own price risk). Electricity retailers will buy a range of contracts (e.g. baseload hedges, power purchase agreements, caps and other option products) from various generators (e.g. wind, geothermal, hydro, ASX, etc) to meet their portfolio needs, and each generator might sell a range of contracts to various parties for the same reason. Generators who have access to energy storage, through any of hydro, gas or coal, will sell contracts which have the effect of allocating some of that storage to other parties. The Huntly swaption is an example of this.

Some stakeholders considered that with greater incentives for a collective management of security of supply risk, more gas would have been stored before supply became tight and gas-fired generators would be better contracted for their supply needs.

Because of the lead time needed to fill available gas storage ahead of any electricity supply shortage (especially given there are limits on the rates of injection and extraction), it is essential to prepare well in advance. As there was little gas stored ahead of the current energy shortage, this suggests that the current incentives may not be sufficient to drive this behaviour for the benefit of the wider market. The holding cost of stored gas is also a significant disincentive to conservatively storing gas in case it is required.

4.2.3 Flexibility

As demand for gas to support electricity security of supply becomes increasingly variable, gas supply must have increased levels of flexibility to support the full range of demand. This flexibility could come from production increases/decreases at the field, increased flexibility in deliverability from the production station, gas storage, demand response, and imports.

Gas field production

Gas fields have a range of production levels within which they can operate. Historically, upstream flexibility was largely provided by the Maui gas field, but this capability has been significantly reduced as the field has come off plateau. Unlike production from conventional gas fields such as Maui and Pohokura, the new onshore 'tight' gas fields in New Zealand are not capable of significantly turning down production during lower demand periods without impacting long-term production capacity.

We heard from producers that it is possible to enable increased long-term deliverability flexibility from their fields, but this comes at an economic cost that would need to be covered by gas users in the price they pay for gas, and over the long-term commercial investment horizon.

Given that, we expect other flexibility mechanisms will become increasingly important as the transition progresses.

Gas storage arrangements/capability

We heard a lot about the roles gas storage could play during the energy transition. Some stakeholders questioned whether the incentives (if any) and mechanisms required to develop additional gas storage are sufficient or whether additional support is required to ensure an appropriate level of storage is available to support the flexibility of gas delivery needed during the transition. Several participants were investigating the potential for developing additional storage as a mechanism to provide increasing flexibility of supply.

Increased storage capacity is a useful tool for shifting the time of use of gas production. It can support electricity security of supply by providing deliverable gas at any time (if it has been stored earlier) to support:

- peaking generation at times of unexpected high demand
- seasonal demand, particularly in dry winters.

Section 5.1 discusses the outlook and potential for gas storage in New Zealand.

Demand response

Historically, very large gas users (especially Methanex) have scaled back their demand during periods when gas supply has been tight due to major supply disruptions and increased during times of surplus supply – to the extent in Methanex's case of mothballing facilities they would prefer to be running.

Consequently, it is often assumed that demand response in the gas sector will occur as a matter of course when the opportunity cost (and therefore price) of gas reaches a level to incentivise gas users to on-sell their contracted gas.

We heard from industrial users that in reality, demand response:

- can occur if value and risk considerations are addressed
- is currently generally voluntary
- is not always possible (e.g. because of the timeframes needed to ramp production up or down)
- requires thermal generators to take on greater financial risk since gas they purchase from demand may well need to be for a period that exposes them to oversupply (especially if it rains after they have contracted gas)
- can create serious issues such as the loss or writing off of product, disruptions to product supply chains, impacts on their ability to meet customer demand, impacts on the health of the industrial plant, potential impacts on staffing, and health and safety risks
- is not something some users are necessarily interested in doing even if it would mean making money, given their own business focus and the need to establish and maintain gas trading capability to effectively do so.

Tolling arrangements to support these demand responses have historically been facilitated by a broker, and several industry participants mentioned that it could be easier to arrange these trades if they had a greater ability to buy/sell gas through short-term over the counter markets as well as the exchange-traded emsTradepoint.

Imports

Imports such as liquefied natural gas (**LNG**) were raised as another option for supporting gas supply flexibility, in a similar way to how Genesis uses imported coal to provide supply flexibility at Huntly. LNG imports could eliminate the difficulties that a smaller gas market would have supporting large fluctuations in demand, or locally produced gas could be stored as LNG. Further detail on the potential role of LNG is included in section 5.9.

While there were very mixed views about whether LNG imports would be a positive development for New Zealand, some stakeholders expressed concerns about barriers to LNG imports as an obvious alternative source of gas if local supply cannot meet demand, or as a counterfactual providing an effective price cap. There are strong parallels to the role of coal and diesel importing for electricity generating. One example of a potential barrier could be resource consenting for an import terminal.

4.2.4 Critical failure impact

Failure of critical infrastructure is another key factor in ensuring security of gas supply. There are currently two main mechanisms within the gas sector to manage potential critical failures – critical contingency management and force majeure conditions in gas supply contracts.

While stakeholders who mentioned them were fairly comfortable with the current mechanisms, a few thought further consideration was needed, particularly around the potential impact of force majeure provisions in a transitional system.

Critical Contingency Management

The Gas (Critical Contingency Management) Regulations 2010 (**CCM Regulations**) set out how industry participants plan for, and respond to, a serious incident affecting gas supply via the gas transmission pipelines.

The purpose of the CCM Regulations is to achieve the effective management of critical gas outages and other security of supply contingencies without compromising long-term security of supply. Mechanisms in the CCM Regulations direct gas consumers to cease using gas according to "curtailment bands" and provide for certain priority designations. These designations ensure that certain gas users (e.g. hospitals) receive priority to gas for certain purposes.

Risks to the transmission system that may cause a critical contingency event are reported annually in the Firstgas Transmission Asset Management Plan. This plan informs gas users of system risks so they are able to make informed decisions of the risk to their own operations.

After the October 2011 Maui pipeline outage, there was broad consensus that the CCM arrangements worked well and the outcomes were generally as intended. Lessons learned from this event were incorporated into regulatory changes and better informed future events that occurred. Participants agreed that the CCM mechanism remained appropriate for managing critical contingency events, although some noted that some of the CCM designations did not sufficiently account for the economic and environmental impacts they would face if operations were ceased.

Force Majeure

Force majeure clauses in gas supply contracts excuse a party from performing its contractual obligations in the event of a supply or demand interruption. For example, if there is an issue with supply from a gas field, the producer can call on the force majeure clause to relieve the duty of delivery of the gas to shippers (gas wholesalers and a limited number of major users), or if a customer experiences a demand interruption it can notify its wholesaler and be relieved of its obligation to take gas.

Historically this mechanism has been suitable as there has been sufficient flexibility in the system to allow shippers to source gas from alternative sources. In the current climate, however, given tighter supply and with limited flexibility, a number of users were concerned that suppliers' ability to call force majeure could have a significant impact on their ability to do business.

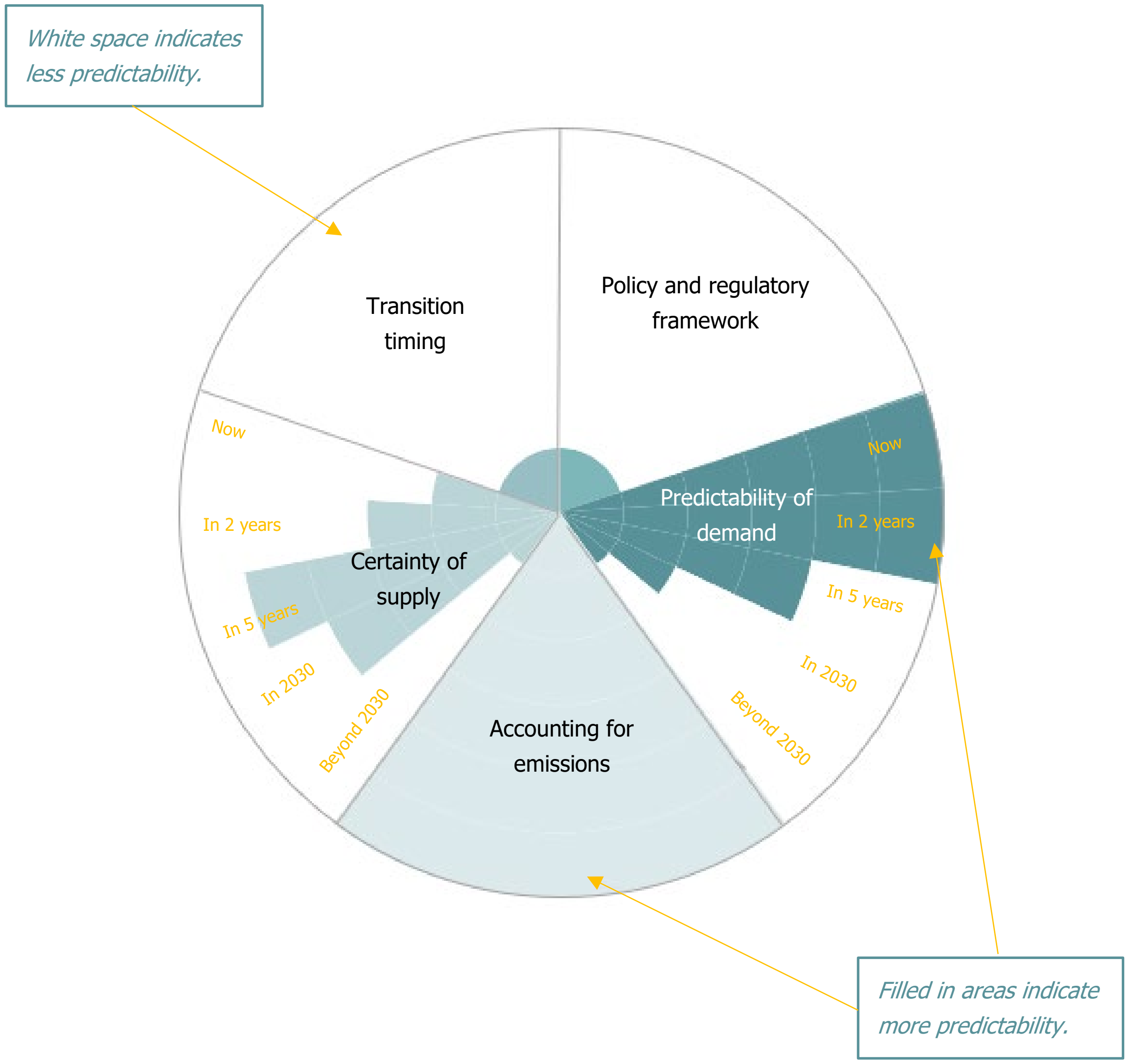
4.3 Unpredictability

Most of our conversations have identified unpredictability across a range of dimensions as having the biggest impact on both electricity security of supply and major users' confidence that they will be able to source the gas they need during the transition – although one noted that some aspects of predictability are not new.

Our conversations identified five main areas of perceived unpredictability:

1. transition timing
2. accounting for emissions
3. supply (including capital to underpin investment)
4. demand (including viability of alternatives)
5. policy and regulatory framework

Figure 6: Predictability themes



4.3.1 Transition timing

Participants said that the gas industry can adapt, but not instantly. Factors including limited capital available to be invested, current technology limitations, and limitations on the capacity and capability of supporting industries that will provide the technologies required for the transition all mean that industry requires time to transition. Participants were engaged with the mission to decarbonise, but were:

- disheartened by the limited time they felt was imposed on them
- unsure how to appropriately assess or stage investment decisions (e.g. if they needed to transition parts of their business relying on different sources of carbon-emitting plant or fuels)
- struggling to make decisions on how to transition, what to invest in, whether to invest, or even whether to remain in business at all.

Examples were given to us of planned (consented) investments and efficiency improvements that had not proceeded due to a lack of confidence that sufficient time would remain for a return on investment to be made. These came from producers, generators and major users and included investments in business efficiency and in substantial potential carbon reductions.

4.3.2 Accounting for emissions

Emissions trading scheme (ETS)

Stakeholders universally understood how the ETS works and factored it into their business planning. Many commented that the ETS and the cost it puts on carbon were effective signals, particularly given that it was technology and fuel agnostic.

A number of participants considered that the emissions price was now reaching a level that incentivises response. As well, they said that forecasts were sufficient to drive investment decisions now to avoid those emissions costs in the future. Carbon prices were a clear driver for stakeholders to factor into their business planning, and many were concerned that supplementary interventions would occur before those prices had the time to feed through.

Disincentives to improve emissions profile

Many stakeholders mentioned that there were opportunities for decarbonisation that they were prepared to take in response to the current and forecast carbon price, but that other external factors were disincentivising this response.

Several examples were given of proposed efficiency improvements to equipment or operations developed in response to the carbon price, which would reduce emissions per unit of product. However many of these had not been progressed or had been put on hold because there was not enough certainty about future operations to justify the investment required.

We heard that some industrial processes fuelled by natural gas actually used up carbon that was ordinarily expected to be emitted (notably in the horticulture industry, where CO_2 supports faster plant growth and by-products are all used in their processes), but that this may not have been adequately considered in the ETS. If the reality were recognised, they would be encouraged to invest in more carbon neutral natural gas facilities rather than continuing with significantly less efficient and higher emitting alternatives or delaying investment until renewable (electricity- or biomass-fuelled) options became technically and commercially viable – which in some cases could be years away or might never happen.

Carbon capture and storage (CCS) was seen as one potential way to improve some participants' emissions profile. However, they were currently discouraged from implementing it as a removal activity since the CCS provisions in the ETS are not yet in force and it is not clear that it is an eligible removal activity, irrespective of the source of the emissions being captured and stored.

Almost all participants we heard from mentioned the contribution that gas and, in particular, improvements to emissions from gas production and use, could make to reducing New Zealand's overall emissions.

4.3.3 Certainty of supply

Given the short-term tight gas supply situation, many participants expressed concern about longer-term certainty of supply.

The gas supply and demand analysis commissioned as part of this investigation and referred to in section 3.1 may well help to alleviate these concerns, as we understand previous long-term supply and demand studies have. However, it is important to note that those studies are necessarily based on assumptions, and while the outcomes predicted are likely to provide a sound overall view, the reality may well be more lumpy than the smooth decline reflected.

From some large users, we heard that more information about the ongoing supply situation is urgently needed, so they can make decisions about their ongoing business and/or order other inputs with appropriate lead time to enable them to continue operating.

Upstream concentration

Participants believed that the elevated risks associated with upstream investment decisions mean that the incumbent producers will be the only ones operating in New Zealand from now on, and as reliance on natural gas decreases, existing players would be expected to leave. For a few industry participants, this raised concerns about a lack of future competition in the upstream – and therefore the level of pricing producers will be able to charge.

Capital availability

As noted, significant investment is needed to ensure gas supply can come to market from currently producing fields. We heard that capital is becoming more and more difficult to access – both from within large international businesses (which regularly review competing capital projects and priorities) and from financiers.

The combination of the tight gas supply situation and the tight financial market means that producers need to spend as much of their available capital as possible on actual drilling / production if they are to provide the gas users need.

In that vein, producers expressed concern about proposed changes to decommissioning provisions in the Crown Minerals Act 1991 and the potential for significant capital to be tied up long term until fields are decommissioned. This could reduce their ability to spend scarce capital on production, which would in turn compromise gas getting to market. In the worst case scenario, it could lead to capital not being made available for production at all.

Contracted gas not guaranteed

A number of gas purchasers said they were worried about suppliers' ability under contract to curtail supply, in force majeure (discussed at section 4.2.4) or other situations. Historically this has been relatively easy for users to deal with, given the ability to source gas from alternative sources where needed. In the current climate, however, given tighter supply and more limited flexibility, this creates greater unpredictability and could have a much more significant impact on gas users' ability to carry on their business.

4.3.4 Predictability of demand

Given the need for demand to underpin investment in ongoing gas supply, unpredictability over the future of major gas users can have a major impact on the gas supply chain.

Methanex is particularly important to the New Zealand gas market, since it is the only user large enough to underpin production investment over a long enough timeframe to make the investment economically viable. If Methanex were to cease operation in New Zealand, a large, stable proportion of gas demand would leave with it. Several industry participants raised concerns about the long-term viability of a domestic gas market at such a reduced scale.

In addition, no other user has provided the level of flexibility buffer that Methanex has over many years of production by reducing its demand when needed, and no other user is able to provide anything like the level of response that Methanex can, given the size of its gas demand. When its production levels and use are lower (as they are currently), its ability to provide a demand response buffer is also reduced – the demand reduction it is able to provide has already been factored in to get to the lower production levels.

With several other major users in the process of assessing their business operations (or in the case of electricity generators, operation of their thermal fleet) and costs escalating, many stakeholders expressed concern that gas demand would become too unpredictable to underpin supply. There is also the potential that demand could even drop to unsustainable levels, leaving it impossible to rely on natural gas for existing assets much sooner even than 2030.

Large-scale electricity demand has a significant impact on the gas system in the same way, although one stakeholder considered the longer-term outlook for a resumption in electricity demand growth has if anything become more positive in the past two years or so. If a major electricity user leaves the market (or stays when it was expected to leave), this has flow on impacts on the need for generation, both in terms of new renewable generation being developed and the expected quantity of thermal generation being required to support electricity security of supply. This in turn affects the gas supply chain.

4.3.5 Policy and regulatory framework

Policy uncertainty

As noted, in a time of rapid change and transition it is to be expected that the policy landscape is uncertain. A number of significant pieces of policy work are underway relating to New Zealand's energy and emissions transition, including this investigation, responses to which may help to relieve some of this and smooth the transition.

Many stakeholders we heard from in every part of the industry supply chain perceived that a lack of policy certainty and predictability had undermined investor confidence. Examples of this included not yet having a clear view of what the Government's response would be to the yet-to-be-finalised Climate Change Commission advice.

They believed that gas has an important role to play in helping New Zealand reduce emissions from more carbon-intensive fuel sources more quickly, as well as in supporting electricity security of supply, and in meeting industrial, commercial and residential energy needs during the transition.

Impact of regulatory intervention

Many raised their view that regulated responses to scarcity could be inefficient and slow, and that taxpayers would ultimately bear the risk.

Some referred to the diesel-fired Whirinaki Power Station as an example of where government intervention had not achieved the intended outcomes. In response to the power shortages of 2003, the government paid $150m for Contact Energy to build and operate the power station as a 'reserve energy scheme'. The 2009 Ministerial Review of the Electricity Market found that the reserve energy scheme actually *reduced* security of supply by encouraging market participants to rely on the (then) Electricity Commission and by discouraging investment by electricity generators in peaker plants, and the government sold it to Contact Energy for $33m in 2011.

In contrast, operating in an industry-led environment:

- Methanex has scaled back its gas demand at times of tightness (enabling scarce gas to go to higher-value gas users) and increased its demand during times of surplus gas supply, underpinning the market and incentivising upstream exploration and development investment

- thermal generators have invested in fast-start peaker plants and gas storage to enable daily and seasonal demand peaks to be met and to ensure that New Zealand's electricity supply is affordable and secure.

Pipeline regulation

A number of participants raised concerns around future gas transmission pricing given that some major gas users are reviewing their business operations, with some likely to leave the market. This demand contraction could lead to the regulated revenue of transmission infrastructure being distributed over a smaller number of users, with marked increases in transmission prices likely.

With fewer parties using the transmission infrastructure over the transition period, stakeholders thought consideration may need to be given to whether changes are required to the regulatory regime for gas pipelines to ensure that the transmission owner earns a sufficient return and assets are maintained. The regime was established for a mature wholesale gas market with relatively stable demand, at a time when it was not envisaged that the assets may not be able to be fully used.

The Commerce Commission, which operates the regime, recognises this issue. It is currently seeking feedback on the emerging issues for electricity networks, gas networks and airports as they relate to the Commission's responsibilities under Part 4 of the Commerce Act 1986 and how it should prioritise these issues when planning its work programme in the near term. It has noted a particular interest in emerging issues that relate to New Zealand's decarbonisation and use of new energy sector technologies and business models. This is a positive step, welcomed by participants, but stakeholders were also interested in the bigger question of whether Part 4 itself is fit for purpose during an extended period of disruptive change was raised.

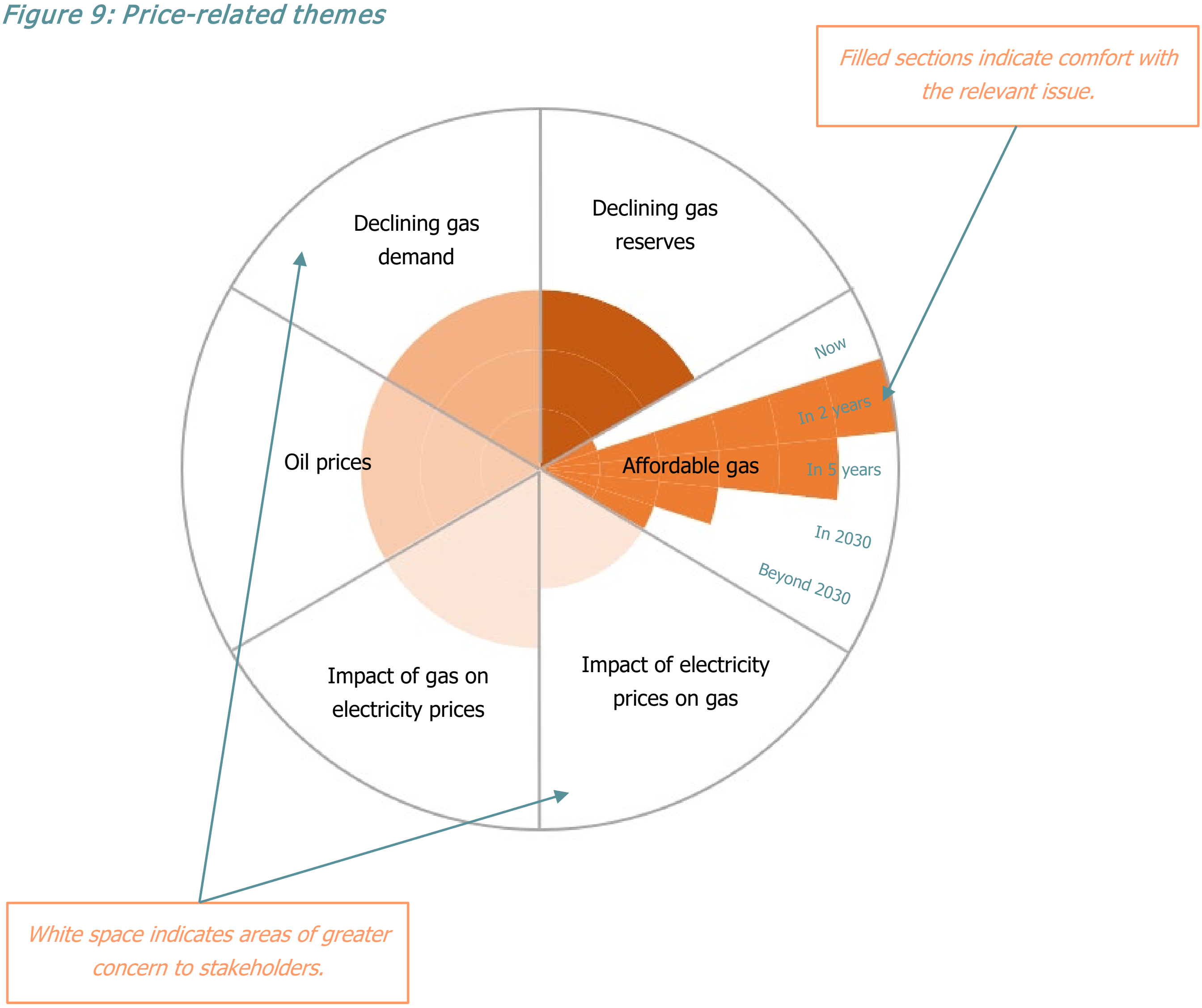
Several participants raised the need for existing gas transmission and distribution infrastructure to remain available as a critical component for supplying reticulated 'green' gases in future – which will improve their affordability and avoid truck movements, providing a safer and more environmentally friendly method of transporting low carbon energy. See section 5.6 for more on 'green' gases.

4.4 Price

A number of points raised relate to the price of gas and electricity, which we have grouped into the following six themes:

1. access to affordable gas
2. declining gas demand
3. declining gas reserves
4. the impact of oil prices on gas price and availability
5. the impact of gas on electricity prices
6. the impact of electricity prices on gas

Figure 9: Price-related themes



4.4.1 Access to affordable gas

Gas users raised concerns about their ability to operate if they were not able to access affordable gas. This was partly in response to the current market conditions, but also related to an ongoing concern about what might happen to gas prices during the transition.

Price information was important for these parties to understand what investment decisions they should be making now. Without a confident understanding of what gas prices are likely to be, they might not be able to accept the risk of continued use of gas.

Some users noted that if prices were too high:

- this may drive them to leave New Zealand or shut down operations before transitioning to cleaner fuels
- transitions from higher emissions components of their operations could be hindered, as there would be insufficient time to earn a return on investment if operations were to cease, or if the natural gas alternative to these high emissions processes was no longer an affordable option
- carbon emissions during the transition period could end up markedly higher than they would be if gas was affordable.

4.4.2 Declining gas demand

Some participants questioned the ability for fewer and smaller parties to underpin investment for gas supply, with concerns that it may consequently become less economic for the upstream to develop gas resources, further driving up the price of gas.

Declining demand is also expected to affect the utilisation of new gas production infrastructure, which affects the gas price that is required for this infrastructure to break even. The price of gas transmission and distribution may also need to increase in order for pipeline owners to maintain returns on their asset base.

Many stakeholders mentioned the risk that overall delivered gas prices could increase if other parties were to cease operations and that this could spiral over time. We were told that delivered gas prices may need to more than double over the period to 2035 in order to compensate new gas infrastructure for a decline in utilisation. This would likely result in an increase in customers choosing to switch away from gas to electricity, or to otherwise reduce their gas consumption, requiring further increases in required prices and tariffs for remaining customers.

As every participant leaves, the remaining parties each have to cover a higher proportion of infrastructure costs, which increases the likelihood of the next participant leaving, and the cost for the remainder.

4.4.3 Declining gas reserves

Some participants were concerned that further 2P (proven) and 2C (contingent) resources brought to market to ensure that demand is met may be more expensive than existing reserves. This was based on the idea that if they had been economic to develop, they would have been developed already. We understand that this is not necessarily the case, given developments are prioritised to meet known demand, rather than based on the costs of production.

However, an important consideration is that some contingent resources come with higher levels of production risk. As the probability of successful development declines, the cost of produced gas could well increase, since more attempts are needed on average to provide gas to market, which could potentially drive prices up.

Also, when a large number of fields are being developed, the impact of a single poor result can be mitigated by the other successful developments. But in a smaller market with less activity, that single poor result can have a proportionally larger impact. More investment may be required to mitigate this proportionally increased risk.

It is unlikely that development will happen at any cost, though, even if the level of demand remains to support it. This is because demand could be met by imported gas or coal, which effectively imposes a ceiling on gas prices even if imports only provide a counterfactual and are not actually progressed (see section 5.9 for more on the potential for LNG imports).

4.4.4 The impact of oil prices on gas

Gas field development is largely tied to oil prices, since a high proportion of the profits from oil and gas exploration come from oil rather than gas. As international oil prices drop, the incentive to invest in oil and gas exploration and development drops as well. This in turn reduces confidence in gas supply for major users and the level of support gas can provide to electricity security of supply. The reverse is true if oil prices increase.

4.4.5 The impact of gas on electricity prices

While electricity security of supply in the traditional sense is about 'keeping the lights on' and is agnostic to price, very high electricity prices can be an indicator that supply is less secure. When there is less gas available, as we are currently seeing, it detracts from confidence in secure electricity supply.

As with electricity, the gas system has many moving parts, and a range of factors including resource availability (and perceived future availability), flexibility, scarcity, the price of (and demand for) end products, contractual terms and risk appetite influence the price that consumers will pay for the commodity being traded.

The electricity sector operates a settlements market with marginal pricing in the spot market. One of the primary roles of the wholesale market is to signal the state of the demand-supply situation across all time periods, from real-time (in the spot market) to years ahead (in the futures market).

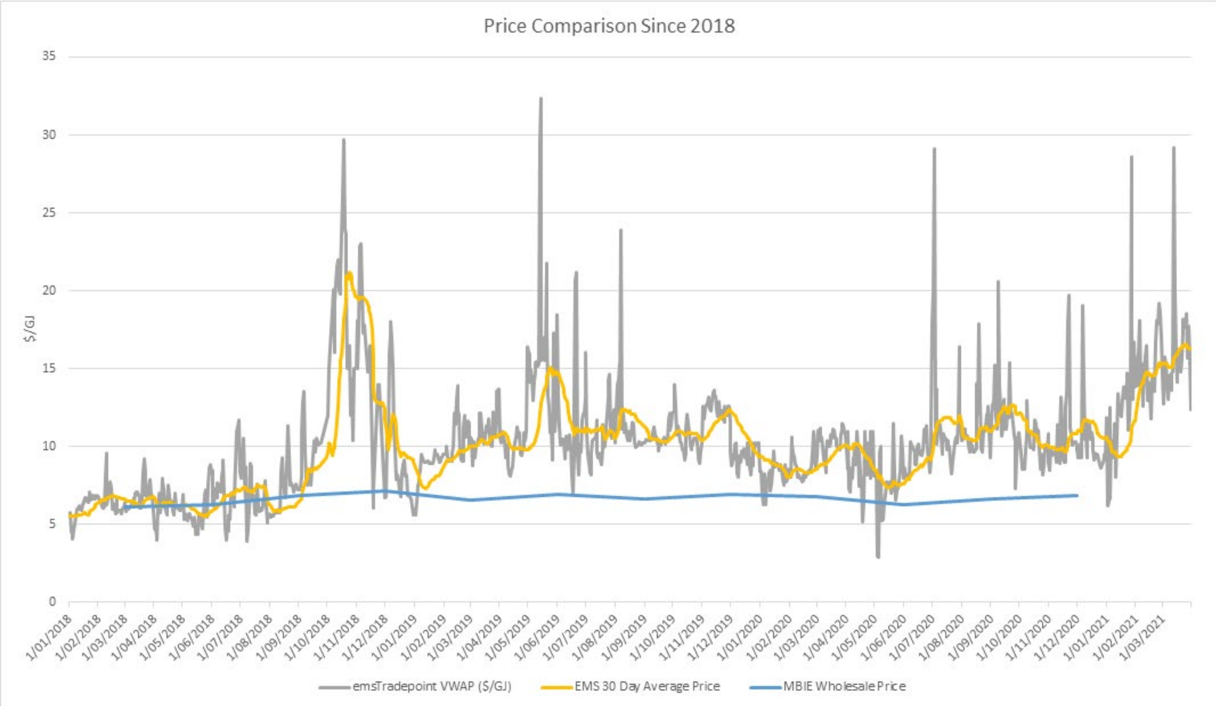
Cost structures across electricity generators vary markedly, from peaking plant (which has a relatively low capital cost per MW, but a high cost of generation per MWh) to wind and solar generators (which have a relatively high capital cost per MW, but a very low cost of generation per MWh). Electricity generators that are dispatched during a trading period are paid the marginal price for their generation, no matter what their offer is. This means, for example, a wind generator offering in at close to $0/MWh will receive payment for its generation equal to the offer of the marginal generator at that time, allowing it to recover its fixed and capital costs.

This spot market is supplemented by the hedge market, which helps participants manage the risk of fluctuations in price that can occur in the spot market and provides price certainty over longer time periods, regardless of how the spot price turns out. However, a party that has entered into a hedge contract for a fixed quantity of power will still be incentivised to consume/generate or not on the margin, based on the spot price signal.

In addition, power purchase agreements are becoming increasingly common, where a purchaser agrees (either directly or within a derivative structure) to purchase electricity on a long-term basis from a generator, usually at a fixed price and often to underwrite or partially underwrite the costs of new renewable generation.

This largely settlements-based market is different to the systems used in the gas sector. Unlike with electricity, the gas spot market (emsTradepoint) reflects only a very small proportion (approximately 4%) of the volume of gas sold and purchased, with 96% of gas traded (including with electricity generators) through Gas Supply Agreements or other bilateral contracts. The gas price under these contracts remains fixed (with PPI or CPI adjustments) for the duration of the contract period and is consistently significantly lower than gas spot prices, as shown in the graph below.

Figure 10: Wholesale vs spot gas prices



In addition, emsTradepoint prices reflect individual trades, rather than a marginal price that all sellers receive as they do with the electricity market system. This means that emsTradepoint prices can impact electricity prices if a trade has occurred with an electricity generator, but typically due to the scale of demand the vast majority of gas purchased by these generators is arranged through bilateral trades rather than the gas spot market. We have seen no evidence that a gas generator will price its generation based on the opportunity cost of selling its gas into the spot gas market rather than on the cost of generating.

Electricity pricing in normal conditions

Under normal system conditions when renewable resources are freely available, its higher short run marginal cost (SRMC) means that gas-fired generation will typically be dispatched by the system operator at a higher electricity price after the offers from the lower SRMC renewables have been taken up. The price generators pay for their gas influences the electricity price at which they will offer their gas-fired generation to ensure they are able to cover their costs, and thus directly impacts the electricity spot price when gas-fired generation is the marginal form of generation.

Gas prices also influence the long-term electricity price (seen in the futures market) through the firming mechanisms and contractual arrangements in the electricity sector, which reflect the prices generators expect they will have to pay to provide thermal generation support in future, and purchasers expect they will have to pay to procure that support. Hydro generators carry out water value calculations to determine their offer prices in response to future risks of energy shortage / surplus and the price of alternative generation.

Along with price, gas availability is a major driver of long-term electricity prices, through the impact it has on generators' confidence that dry year risk will be covered. The more gas-fired generation that is available to cover for the risk of scarce hydro supply in a dry year, the less risk there is to manage in the system, so offers can confidently be set lower.

A good example of this is the increase in average electricity prices since 2018 when prices in the electricity system started to rise to reflect the tighter gas market.

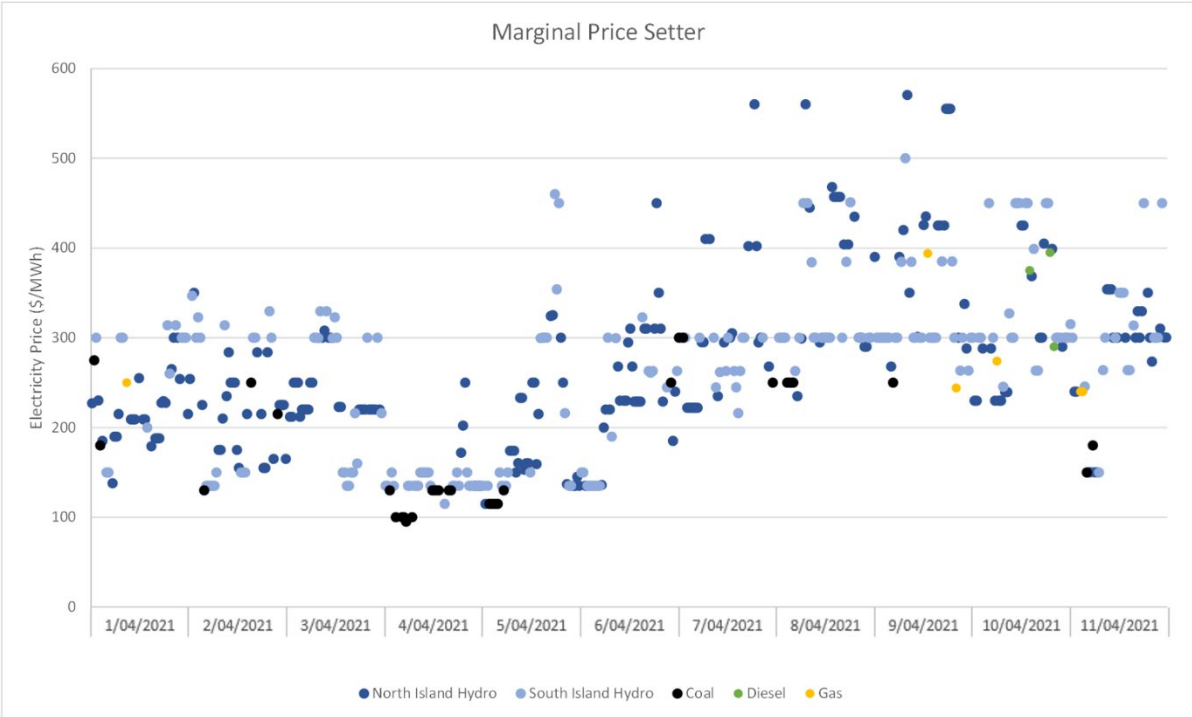
Electricity pricing in constrained periods

The operation of the electricity market is quite different when there are energy constraints.

Typically in a sustained dry period, hydro generators will offer into the spot market at a higher price in an effort to conserve water by incentivising other generation to be dispatched first. This means gas-fired generation will run harder to fill the gap produced by lower hydro generation volumes and may more frequently act as the price setter as it displaces the (at the time) more expensive hydro generation.

However, when overall energy is short and available thermal generation is similarly constrained, and hydro is still needed to meet demand, it is often the higher hydro generator offers that set the electricity market price. The graph below shows a sample at the start of April where the highest of the marginal prices are set by hydro generation, which is dispatched in times of energy shortage only because all cheaper alternatives have been dispatched already.

Figure 11: Marginal electricity price setter



4.4.6 The impact of electricity prices on gas

Electricity prices can set gas prices in constrained periods

At the same time, a key driver of increase to the opportunity cost for gas is a shortage of energy in the electricity sector. If gas generators have multi-year gas contracts then the purchase cost of their gas will not be affected by the wholesale electricity price. On the other hand, during constrained periods, the electricity price can set the gas price in short-term trades due to the opportunity cost of gas used for electricity generation.

For example, a tolling arrangement might be entered into between two generators, where one sells their gas to another more efficient plant so more GWh is produced per GJ of gas at a net benefit for New Zealand as a whole. As the selling party is no longer able to generate from that gas and capture profits from the elevated electricity prices, they will on-sell their gas at a price that ensures they are not relinquishing these profits. Therefore the gas price lifts to ensure the cost of the seller's relinquished electricity generation is covered. Here, high electricity prices driven by energy shortage are lifting the gas price for short-term trades outside of existing multi-year contracts.

Current situation

Over the last few months, we have seen a sustained period of low hydro inflows coupled with gas supply constraints. While this investigation is focused on the transition period rather than the particular set of challenging circumstances that exist at the moment, the current situation may provide an indication of the challenges ahead and the type of situation that, if not actively managed, could potentially become increasingly common during the transition.

Fuel shortages (both water and gas) have meant generation fired by other thermal fuels (coal and diesel) is being dispatched to ensure uninterrupted service and/or plant availability, for example seeing Genesis as the operator of the Huntly power station importing large volumes of coal to ensure the ongoing operation of its three dual-fuel Rankine units to meet market electricity demand.

When considered together, there is overall tight energy supply across the board, which has seen very high wholesale electricity prices, and gas-fired generators and large industrial users competing for what gas is available. Given high electricity prices, gas-fired generators have been able to outbid industrial users for marginal gas and the result has been an upwards spiral of wholesale gas prices.

As wholesale gas prices increase, or gas users become more concerned about their potential to be significantly higher in future, they may become less willing to accept the risk of continued use of gas (see section 4.4.1) and the spiral of users leaving the market and prices further increasing continues (as discussed in section 4.4.2).

Demand response

Typically when energy is constrained, elevated prices incentivise increasingly expensive generation to be dispatched, but when dispatchable generation reaches its limit due to energy constraints, demand response becomes a key mechanism for returning supply and demand into balance. This demand response could be in the form of:

- electricity demand reduction, so that less thermal fuel is needed to meet electricity market demand
- gas demand foregoing its gas allocations to allow further generation from idle gas-fired generators that are fuel constrained.

Demand response is largely driven by price, but also impacted by a broader range of considerations as noted below. Industrial consumers exposed to the electricity spot price may reduce their consumption and scale back their operations if the cost of consuming electricity becomes too high. Consumers with fixed-price, fixed-volume hedges face an incentive not to consume if they can earn more by selling back contracted electricity. Similarly, gas users could be prepared to forego their gas allocations if offered a suitable price to cover the costs of their gas as well as the flow on costs and effects of foregone product from their operations.

This demand response can provide a degree of offset to decreasing levels of supply, thus contributing to security of supply for electricity generation and for other gas users during the transition.

However, demand response can come with significant flow on impacts including the loss or writing off of product, disruptions to product supply chains, inability to meet customer demand, impacts on the health of plant, health and safety risks, and impacts on staffing – in some cases to the extent of job losses and consequent social impacts.

Q4: Have we captured the issues fairly and accurately? Have we missed anything?

5. Potential solutions

In our conversations over the last three months, and in our commissioned input analysis, a number of potential next steps and solutions emerged, which we include here for your comment and feedback. Gas Industry Company has not yet assessed these and intends to consider and respond to them after this consultation. There is unlikely to be a single solution and our initial thinking sees potential in a set of solutions linked to providing greater confidence to support the required investment in gas supply and flexibility. We have included the full suite of suggestions from stakeholders for your feedback. These include:

- determining whether the incentives (if any) and mechanisms required to develop additional gas storage are sufficient
- making more comprehensive and timely information available in relation to gas supply and demand
- considering how to ensure the major risks to secure gas supply and their impact are better understood
- enabling and encouraging wider use of Emissions Trading Scheme (**ETS**) tools, and providing clarity about its boundaries
- reconsidering the suitability of the price / quality path regulatory framework for gas pipelines
- clarifying how 'green' gases (such as hydrogen and biofuels) will be treated
- exploring whether some form of encouragement or support is needed for long-term wholesale gas contracts (to be broken up and sold in shorter-term chunks) to be entered into where end-use demand is unpredictable
- increasing policy predictability
- ensuring there are no barriers to liquefied natural gas (**LNG**) imports
- considering whether a reserves / capacity market for energy is desirable to ensure security of supply
- considering whether government investment may be needed to ensure security of supply.

Some of these suggestions will be more favourable than others and some may simply not be feasible in the New Zealand context. In most cases, specific analysis has not been carried out to assess their feasibility and effectiveness. However, we are keen to hear any feedback about these any more detailed information you may be able to share to inform us on how feasible or effective they might be, as well as any other solutions or steps you think could assist with addressing the issues raised.

5.1 Gas storage

We heard a lot about the roles gas storage could play during the energy transition and several stakeholders questioned whether the incentives (if any) and mechanisms required to develop additional gas storage are sufficient or whether additional support is required to ensure an appropriate level of storage is available to support the flexibility of gas delivery needed during the transition.

Mechanisms could potentially range from payments to those who keep stored gas available to support security of supply (effectively a capacity payment), to subsidies for development of storage. Government could assess whether gas storage could provide an appropriate interim energy storage solution for dry years until renewable solutions are developed and operating. The planned mechanism for funding the New Zealand Battery market operations (cost of filling, and the price/security status at which supply is made available) could potentially be deployed for gas storage while renewable battery options are developed.

Storage is one area where we have carried out some work in relation to the role it could play and whether additional capacity is needed to support the transition.

The role of gas storage

Gas storage is a useful tool for effectively shifting time of use of gas production:

- when there is excess supply, e.g. a short-term oversupply due to demand side plant failure / force majeure event or unexpected extra production from a newly drilled well
- when there is gas price variation between low (typically summer) and high demand periods
- to enable parties to manage risk by having some reserve:
    - to firm or provide seasonal support for electricity generation
    - in case of gas production (or supply) failure.

This storage could be in the form of an existing field being repurposed (like Ahuroa), or above ground tanks to store LNG or liquefied petroleum gas (LPG). Some participants also suggested utilising some of the transmission pipeline as an alternative storage option if the users on that section of pipe were to disconnect (or where the pipe is looped).

The Ahuroa gas storage facility provides New Zealand's only current significant gas storage, with the ability to inject and extract up to 65 TJ per day (each) and a total 18 PJ of capacity. However, Ahuroa has not been more than 40% full since 2018. If gas availability had been stronger during 2018-2020 and there had been more commercial incentive to fill it, Ahuroa would have been able to contribute much more substantively to current system security.

Is further storage needed?

The increasing penetration of renewables and demand for load firming is likely to further increase the requirement for flexibility over the next decade. This is despite an expected decrease in overall demand for gas to support electricity generation gas as baseload and backup thermal plant is increasingly replaced by new renewable generation. This makes storage and other flexibility mechanisms more important.

In terms of required quantities and flows, analysis shows the following:

- The downstream and expected future major industrial loads tend to be complementary in their level of flexibility they require, or put another way there is a balancing or smoothing effect between loads. This means the overall system flexibility needed to provide security of supply to them is likely to be around 50-60 TJ per day in each direction (injection and offtake), meaning a total gap between maximum and minimum demands of around 100-120 TJ per day. The other element to this is the size of the storage facility needed to meet this downstream and industrial demand through the year, which analysis has estimated to be around 4-5 PJ.
- Demand for stored gas to support electricity generation is expected to be significantly greater. The electricity generation sector is estimated to require operational flexibility of up to 250 TJ per day (or more if the Huntly Rankine units run on gas rather than coal).
- Given the compounding uncertainties of hydrology, whether Tiwai Point will remain operating beyond 2024 and the pace of transition path towards the 100% renewable generation policy target, the total potential call on thermal (gas and coal) generation could vary, at its extreme, by as much as 70 PJ in any given year. At present there is insufficient supply to account for this variation and, even if there was, there is insufficient storage capacity and

flexibility to deliver this range. Judging from public statements from thermal generators on the extent of extra gas storage that is needed and the volume of coal that is currently being imported, it appears the thermal generation sector expects to require an additional 25 PJ of flexible gas volume in any given year.

It is important to note that even this level of additional storage would not on its own provide full risk insulation against upstream deliverability issues, e.g. if a field suffers an outage. As noted above, we expect a suite of existing mechanisms and other solutions will be needed to provide the flexibility and security required.

Risks for investors in new storage

The addition of new local storage faces two key risks:

- the time duration, over which local gas storage would be needed as New Zealand continues its transition to renewable electricity
- unpredictability over the potential development of the New Zealand Battery Project.

If an investor could get comfort that the timeframes involved still make investment in storage viable, the other risk around a local storage option is the working capital which would be tied up for an unknown amount of time as gas, which had been previously paid for, was kept in reserve "just in case" of a low hydro sequence. In theory, this could tie up 10-20 PJ of gas for up to five years, which depending on gas prices could represent significant expense.

5.2 Increasing information availability

Some industry participants wanted more comprehensive and timely information in relation to gas supply and demand, so that expected imbalances can be more effectively dealt with ahead of time. This could be similar to the Australian Energy Market Operator's annual gas statement of opportunities but potentially more frequently published.

Imbalances that affect investment may include material changes to expected demand or supply. Frequent updating of demand and supply imbalances would be likely to improve risk management, predictability and the use of hedging tools.

New Zealand Petroleum and Minerals' information gathering and reporting function could be expanded to include demand side information and to operate on a more frequent schedule – as frequently as weekly or monthly. Alternatively, this function could be provided by Gas Industry Company, which already collects demand-side data.

Additional regulatory powers may be required to collect the required information.

As noted in section 4.1.2, there are some developments underway, which should go some way towards providing the increased information participants would like to see:

- Gas Industry Company intends to develop an information portal on its website, which will be a one-stop launch-place for parties to access publicly available information. Information now available in graph form on Gas Industry Company's website is the first step in the development of the portal[7]
- the Electricity Authority has added links to thermal fuel data to its Electricity Market Information (EMI) website
- further work is underway on whether additional information disclosure is required in relation to contract price and volumes and/or major user outages, as part of Gas Industry Company's information disclosure workstream.

[7] See https://www.gasindustry.co.nz/about-the-industry/gas-industry-information-portal/gas-production-and-major-consumption-charts/

5.3 Better understanding of risks

We heard that many of the current challenges may well have occurred or been exacerbated by risks (e.g. field or pipeline outages, earlier than expected field decline etc) not being well understood. Accordingly, there was a suggestion that consideration be given to how to ensure that major risks to secure gas supply and their impact are better understood.

This could potentially involve:

- disclosing major risk information (alongside supply and demand information, as above, if implemented). This could take the form of risk assessments (similar in authority to electricity risk curves) to assist those businesses for which gas supply is a relatively small part of their overall operations to more readily factor those risks into account in their commercial decision making
- considering requiring certain gas industry participants to conduct stress tests along the lines of those in the electricity industry. If these are not already being undertaken, this may allow participants to see how their gas supply position and costs could change if major risks eventuated, or simply be published at the level of confirming participants 'meet the stress test thresholds'. The latter would create greater pressure as conditions approached the stress threshold but would require less disclosure of commercial hedges and contracts.

5.4 ETS

Most industry participants we spoke to were very comfortable with the operation of the ETS and understood how they needed to change their business to work with it.

They considered that gas could better play its role in the transition if wider use of ETS tools were enabled and encouraged, including using the ETS as the main mechanism to encourage increasingly lower emissions activities. This would provide clarity about how abatement of emissions will be treated (e.g. if CO_2 is used or captured and stored), provide economic predictability to investment decision makers, and credits would incentivise gas users to transition away from lowest value use of carbon first.

Participants also wanted clarity about the boundaries of the ETS to enable them to better assess the viability of existing assets or proposed investments. This could include clarifying where policy outcomes are not expected to be achieved by the ETS, and how alternative policy will be assessed.

5.5 Regulatory framework for gas pipelines

Existing pipelines are regulated by the Commerce Commission under Part 4 of the Commerce Act. These regulatory powers exist to regulate markets where there is no competition and regulation is required to protect consumers. The relevant considerations may not be appropriate to a declining gas market where consumers have an interest in the maintenance of the pipeline network for security of supply.

Several participants across the industry thought it would be timely to reconsider the appropriate form of competition regulation for energy sector participants as the sector moves toward Net Zero Emissions.

The Commerce Commission is currently seeking feedback on the emerging issues for electricity networks, gas networks and airports as they relate to the Commission's responsibilities under Part 4 of the Commerce Act 1986 and how it should prioritise these issues when planning its work programme in the near term. This is a positive step, but stakeholders are also interested in the bigger question of whether Part 4 itself is fit for purpose during an extended period of disruptive change was raised.

In addition, the need for existing gas transmission and distribution infrastructure to remain available as a critical component for supplying reticulated 'green' gases in the future was raised as noted above. Stakeholders were keen to see this taken into consideration as regulatory developments are considered.

5.6 'Green' gases

Several stakeholders were keen to see work done to clarify how alternative 'clean' gases (hydrogen and biofuels) will be treated and how they will be supported (as specifically as possible) as a mechanism to continue to meet gas demand as we transition away from natural gas. Possible examples include potential promotion by government, allowing for increasing blends over time (with natural gas supported to continue in decreasing proportions as alternatives develop and their proportions increase), and ensuring continued viability of the infrastructure (particularly pipelines) needed to deliver new gases.

We set out below a brief description of what these gases are and what they could do. We are interested to hear your views on the roles they could play to support the transition and beyond.

5.6.1 Biogas

Biogas is an energy-rich gas produced by anaerobic decomposition or thermochemical conversion of biomass. Like natural gas, biogas is composed mostly of methane (CH_4) and carbon dioxide (CO_2). Biogas can be burned directly as a fuel or treated to remove the CO_2 and other gases for use just like natural gas. Treated biogas is sometimes referred to as *renewable natural gas* or *biomethane*.

Biogas also has the ability to be refined and injected into the reticulated natural gas network using current infrastructure. Although there are currently no material examples of this occurring in New Zealand, there are international examples, and a study is underway to investigate the potential for a biogas industry that could include reticulation[8].

Today New Zealand can produce up to around 4.7 PJ of biogas per annum (production was 3.63 PJ in 2020 according to MBIE data) from landfill and municipal wastewater, which is predominately used for heat and electricity production at its production site.

Estimates of biogas potential in New Zealand vary, but a recent report[9] suggests that further investment in biogas technologies could provide an additional 14 PJ of production per annum, taking total biogas production to more than all projected mass market (residential, commercial and agricultural) gas demand by 2030, or around 40% of all projected mass market and industrial gas demand (excluding petrochemicals and electricity generation).

This additional biogas would come mostly from livestock manure, but also industrial waste, crop residue, municipal and commercial food waste, and municipal wastewater. The report notes that feedstock co-digestion could further increase the potential.

Work is also being undertaken to investigate how New Zealand's liquefied petroleum gas (LPG) industry could be converted to renewable LPG. Renewable LPG is chemically identical to conventional LPG and so is suitable to be used within existing infrastructure. The LPG Association is investigating a pathway to 100% renewable LPG by 2050 and we understand the association sees this as viable so long as investment in the current industry continues.

5.6.2 Hydrogen

The New Zealand hydrogen industry is in its infancy; however several pilots and projects relating to hydrogen have recently been carried out or are in progress.

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[8] The study is being funded by Beca, Firstgas Group, Fonterra and the Energy Efficiency and Conservation Authority. The first part of the study is expected to be released during the second quarter of 2021 and will look at what the uses and economics of biogas are, who could benefit, and what incentives could be put in place to encourage developments.

[9] Beca, *Biogas Technical Memorandum – for inclusion in Firstgas Group Climate Change Commission Submission*, 23 March 2021

Many of these relate to how hydrogen could decarbonise the transport sector, but work is also underway to investigate how hydrogen could directly displace natural gas. In March 2021 Firstgas Group released a hydrogen feasibility study and a target to reach a 20% blend of hydrogen in the natural gas networks by 2035 and 100% hydrogen in the pipelines by 2050. The target would rely on continued investment in the gas networks during the trial phases, with the first 1% of hydrogen blend expected in around 2030.

The research shows that there are some issues relating to transporting hydrogen blends and pure hydrogen within the gas networks and these would need to be resolved before any hydrogen could be injected. However, significant work is being undertaken internationally and there are already examples of hydrogen being injected successfully into natural gas networks. The research also shows that a 20% blend of hydrogen in New Zealand would not impact most gas appliances, although the higher percentage blends targeted over time would require appliance and/or burner upgrades.

5.6.3 Natural gas as an enabler

Maintaining existing infrastructure (particularly the gas pipeline network) to transport green gases will improve their affordability and avoid truck movements, providing a safer and more environmentally friendly method of transporting energy. While green gases could still come to market in bottled form or be used directly on site, maintaining the network will be crucial if any green gases are to be reticulated (and will increase their applicability).

Natural gas itself will also be needed during the transition:

- to continue to supply energy for uses not well suited to electricity conversion
- to blend with green gases as they come on stream in increasingly greater quantities in order to enable infrastructure, equipment and appliances to remain operational until those gases can supply the energy needed.

5.7 Support for long-term wholesale contracts

As noted in section 4.1.3, we understand that gas wholesalers in New Zealand now generally purchase gas only to meet a known demand, and sell to gas users only when they have a known supply. This means that there is limited ability to meet the needs of users with shorter contracting timeframes unless new supply comes on stream.

A stakeholder suggested exploring whether it would be helpful to promote a mechanism or market for long-term gas contracts (which producers want) to be converted and sold into short-term contracts (which consumers want).

Alternatively, mechanisms could be explored to encourage or support more liquidity in the market for long-term contracts, so that purchasers who find themselves over-contracted could exit their positions more freely.

5.8 Increasing policy predictability

Stakeholders were particularly keen to understand more around the nature of the transition to a low carbon future, the timing of potential government-backed initiatives, and the range of policy and regulatory instruments expected to be used.

Many stakeholders picked up on the Climate Change Commission's suggestion that a new New Zealand Energy Strategy could potentially provide clear outlines of regulatory intervention and tools – provided it was developed within a year and with comprehensive input from the broader energy sector.

5.9 Potential contribution of LNG

A number of stakeholders raised the potential role of LNG in New Zealand, and their views ranged widely. At one end, some considered LNG imports would be a sensible option to support a reducing natural gas market and / or the increasingly flexible gas supply needed during New

Zealand's transition. Some mentioned the role they thought LNG could play in keeping domestic gas prices down even if not widely used. At the opposite end of the spectrum others thought even considering LNG imports was an indication of policy failure, and there were mixed views about whether LNG imports would be a positive development for New Zealand if they were needed for security of gas supply.

Stakeholders thought LNG imports could play a role in supporting gas supply flexibility, in a similar way to how Genesis already uses imported coal to provide fuel supply flexibility at Huntly and how LPG suppliers already import LPG to supplement indigenous supply. LNG imports could eliminate the difficulties that a smaller gas market would have supporting large fluctuations in demand. Contracts for imports could be arranged to align with expected periods of tight supply in the domestic market. The method by which the imports are brought into New Zealand means that it might be valuable to pair importing facilities with storage, to allow greater fluctuation in supply.

Some considered it would be helpful in any case to ensure there are no barriers to LNG imports as an alternative source of gas if local supply cannot meet demand, or as a counterfactual providing an effective price cap (e.g. resource consenting for an import fuel terminal). Others identified the potential for local natural gas to be converted to LNG and stored as a flexible backup fuel, given its high energy density and ability to be stored in tanks rather than in underground reservoirs.

New Zealand has not previously developed or imported LNG (generally because the economics have not supported it to date) and LNG technology and markets have seen major developments in the last decade. Because of this, understanding of whether and how LNG could support the transition was limited, so Gas Industry Company commissioned some further analysis to support a clearer picture of its potential roles. That analysis is ongoing and we expect it to be completed by the end of the consultation period.

About LNG

At its point of origin, LNG is simply natural gas that has undergone a refrigeration process that condenses it to a liquid state. LNG is 1/600th the volume of its gaseous state and, as a liquid, is not combustible, making it ideal for bulk transportation to market. At its point of use, LNG is heated to restore it to its gaseous state then injected into the local gas transmission and/or distribution networks or combusted on site.

The energy density and transportability of LNG, combined with the clean burning characteristics of natural gas, has made it a commodity of increasing demand globally, often to substitute for coal. Compared to imported coal (which is being increasingly relied on to run the Huntly Rankine units):

- a single LNG shipment contains more than 4 PJ of energy equivalent fuel, whereas a coal shipment contains around 0.65 PJ – a six-fold difference
- gas supports the operation of higher-ranking generating plant – gas peakers are around 15% more fuel efficient than the Huntly Rankine units and Combined Cycle Gas Turbine generating units are around 50% more efficient
- LNG presents 40% lower CO_2 emissions – meaning that a single LNG cargo carries with it 150,000 tonnes less CO_2 emissions than its fuel-equivalent of coal for a saving at current carbon prices of $5.6m per LNG cargo
- offsetting these benefits, and despite being both cleaner-burning and carrying an emissions footprint roughly half that of coal, imported LNG is considerably more expensive than imported coal on a per-unit basis.

There is now a vibrant international LNG spot market, with tradeable derivatives and smaller-scale liquefaction and regasification solutions becoming increasingly mainstream. This includes floating liquefaction (FLNG), floating storage units (FSU), floating regasification units (FRU) and floating storage and regasification (FSRU) options, each of which are also now common. LNG is also seeing increasing uptake into domestic fuel pools across both stationary energy and mobile energy (e.g. land and sea fuels, particularly in high-horsepower applications such as larger sea vessels and heavy goods vehicles).

Potential role of LNG in New Zealand

New Zealand does not currently have infrastructure to enable the handling of LNG. If LNG infrastructure is developed, it could provide substantial additional gas market capacity and flexibility to complement existing indigenous supply (e.g. through the increased storage potential and portability LNG offers). This could improve security of gas and electricity supply, and reduce emissions, using either:

- **import LNG** from an LNG-producing nation, such as Australia (requiring construction of receiving infrastructure, with the LNG itself being subject to international pricing)
- **domestic LNG** produced from indigenous gas and held as stored energy for release into the market as demand conditions support doing so (requiring construction of both liquefaction and regasification infrastructure).

Compared to domestic LNG, import LNG would:

- increase total supply into the market, whereas domestic LNG would involve 'shaping' available indigenous gas supply to better meet demand
- likely be much quicker, using largely seaborne (i.e. floating) handling infrastructure, whereas domestic LNG would likely require the construction of permanent and potentially multiple land-based liquefaction and regasification installations
- be lower priced overall, with the potential to reduce costs further by sharing the cost of shipping with other LNG importing nations whose high demand season is complementary to ours
- provide far greater operational and commercial flexibility, including an ability to permanently demobilise at relatively short notice and at much lower cost if and when imports are no longer required to supplement local market supply.

LNG would provide substantial additional gas market flexibility than New Zealand's current gas situation. FSRUs are able to deliver gas at up to 500 TJ per day but can be throttled-back to feed-in as low as the "boil off rate" of as little as 10 TJ per day. To put this in perspective, the maximum feed-in rate would be more than sufficient, transmission permitting, to fuel all 2.4 GW of thermal electricity generating capacity currently in operation at the same time – including all three coal-fired Huntly Rankine units and the diesel-fired Whirinaki station.

Under either concept (import LNG or domestic LNG), LNG could also support the transition and decarbonisation of other fuels including as an alternative to diesel for standby fuel for site-specific applications including power generation and industrial processes and for road and marine transport applications.

We expect that if LNG imports were committed to, they would:

- serve principally as a security of supply backstop for major users in New Zealand (LNG would be a comparatively expensive 'last mile' solution for buyers that may otherwise not be able to secure gas, with cheaper indigenous gas production continuing to meet as much market demand as possible)
- primarily be a potential solution for electricity generators, gas wholesalers, large industrial users and gas retailers; and very unlikely to be viable as an option for petrochemical producers
- likely be only temporary in duration, because expected investment to develop new indigenous gas along with falling demand is likely to see supply margins stabilise from 2023-24

- potentially serve as a backstop in the longer term to cover residual demand if falling demand means field development is not underwritten.

This could see LNG imports feature in the New Zealand market for a relatively short period of time, which would mean an import LNG solution could be consistent with transitioning to 100% renewable electricity generation by 2030 while also providing improved security of supply across the transition period.

LNG options for New Zealand

Analysis indicates a supply gap equivalent to between one and six LNG cargoes per annum, a gas-equivalent of between 4 PJ and 25 PJ pa. This could be received at any of three potential sites where receiving infrastructure could be located (Marsden Point, Port Taranaki or Maui-A). Other sites may also be feasible. All would involve the integration of floating receiving units with existing gas infrastructure. Implementation lead times would rely principally on approval timings, consenting and FSRU availability.

The strongest initial potential appears to be at Marsden Point, which is the 'fastest fit' option in that it could potentially be brought on stream within 12 months of a commitment decision, given existing resource consents held by Refining NZ that may already allow for LNG import operations. However, existing pipeline transmission constraints mean that gas deliveries into the existing pipeline network would be limited to 20 TJ per day (or 30 TJ/day with a $20-25m spend on compression). A further 50-60 TJ/day could be delivered by trucking LNG to a receipt point south of the constraint, such as the Henderson compressor station. While not ideal, the movement of fuel by road is standard industry practice. Compared to coal transported to the Huntly power station, though, delivery of the equivalent energy as LNG would require half as many truck journeys (from Marsden Point to Henderson, as opposed to from the Ports of Tauranga and Auckland to the Huntly coal stockpile).

The Maui-A and Port Taranaki options would likely involve materially longer lead-times due to the likely need to design and build a bespoke mooring system (in the case of Maui-A) and dredging (in the case of Port Taranaki). In both cases, if the resource consenting process was able to be streamlined then lead times would likely be much shorter.

Of the three options, Port Taranaki is the 'cleanest fit' in that it offers the strongest integration with existing gas infrastructure. This includes with the Ahuroa gas storage facility, which would likely feature as a cornerstone component of a wider Port Taranaki-led LNG supply chain. If consenting was to be streamlined, we understand that a lead time of 12-24 months post committal could likely be achievable, noting that this may not be quick enough to provide best value, given the domestic gas outlook.

Likely costs

The supply and flexibility security that LNG could potentially bring to the wider energy sector would tend to support a fee structure that involves:

- a fixed price call option to cover infrastructure costs
- a variable strike price to apply to acquired LNG.

This is a similar approach to the fee structures that are thought to apply to access Ahuroa gas storage capacity and to the Huntly dry year swaption agreements between Genesis, Meridian and Contact.

Under this structure, fixed operating costs and a return on capital invested would be covered by users in each year. The payment to cover fixed returns and opex would be seen as the cost of buying an option to import gas, and could be compared to the cost of contracting capacity at storage facilities.

Analysis shows that annual costs would likely range between $80-140m pa for each of the Marsden Point and Port Taranaki options, although there is potential to recover as much as $20m pa under the Port Taranaki option by sub-leasing the floating storage and regasification unit to the carrier market. For Maui-A, this annual fixed cost would likely range between $140-380m. This broadly equates to a cost per GJ of maximum deliverable quantity (**MDQ**) of $330-560 per GJ of MDQ for Port Taranaki, $1,030-1,770 per GJ of MDQ at Marsden Point and $1,420-3,800 per GJ of MDQ at Maui-A. In comparison, estimates of the cost of Ahuroa storage capacity are currently at around $500-525 per GJ of MDQ.

The cost of the gas itself would be determined by international markets. Based on recent trends of the spot market around the Asia Pacific region, this cost would likely average between $9.60 and $11.80 per GJ excluding carbon. In addition, a variable cost per GJ of using the facility would apply, which could be as low as $0.80-1.00 at Port Taranaki or as high as $2.60-4.60 for Marsden Point. Maui-A lies in between with a likely range of $0.90-1.30 per GJ.

While this sees the cost of LNG imports materially higher than established commodity-only price benchmarks for indigenous gas, it is worth noting that:

- LNG-backed gas would stand in the market as marginal gas at or near the bottom of the merit order and by doing so serve to provide users with a ceiling price proxy
- the LNG-backed commodity price would include an embedded value for flexibility whereas existing commodity-only price benchmarks for indigenous gas do not
- LNG would provide supply certainty and flexibility during periods of constrained indigenous gas availability, including cover for major unscheduled asset outages.

5.10 Reserves / capacity market for energy

One idea that was raised (although with a wide range of viewpoints on its desirability) relates to considering whether a reserves / capacity market for energy is desirable to ensure security of supply.

If established, this could ensure that fuel (including thermal fuel) was available when electricity supply was constrained. It would require some attention to who would operate the market and how it would operate, the detail of how the capacity was purchased, and the conditions under which the capacity would be released to market.

5.11 Potential government investment

Some parties we heard from thought consideration should be given to whether government investment is needed to ensure security of supply if thermal generation to support security of supply or gas supply to critical industry becomes commercially less viable during the transition, e.g. full or partial investment / ownership / buyer of last resort for gas production, flexibility (storage or pipelines), or electricity generation.

Q5: What are your views on the potential solutions stakeholders have raised? Can you share any more detailed information to help inform us on how feasible or effective they might (or might not) be?

Q6: Are there any other potential solutions?

Q7: Do you agree that there is potential in a set of solutions linked to providing greater confidence to support the required investment in gas supply and flexibility, and that there is unlikely to be a single solution?

Q8: What are the most important next steps to ensure that gas can support security of supply in the electricity market and that major gas users have sufficient certainty/transparency about gas supply for their operations during the transition?

6. Next steps

We are keen to receive your feedback and suggestions as to next steps, particularly in response to the questions.

Following this consultation, we will publish submissions (publishable versions if confidential information is supplied) and develop a report for the Minister of Energy & Resources by mid 2021 setting out:

- how gas market, commercial and regulatory settings:
  - affect overall availability and flexibility of gas supply
  - support security of supply of electricity and ensure thermal generation is provided during the transition
  - provide major gas users with sufficient certainty / transparency about gas supply for their operations
- our view on whether those settings are fit for purpose for the transition to 100% renewable electricity by 2030 and to Net Zero Emissions by 2050
- what issues exist or are likely to emerge that will affect security of supply for electricity or certainty / transparency about gas supply
- a proposed work programme to enable the gas industry to help support the transition.

We may approach stakeholders for further input before finalising our report if needed and if time permits – noting our concern to ensure that balanced advice is available to the Minister in a timely way in order that it can play a part to support Government decision making alongside other work currently underway.

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- Flick Electric
- Fonterra
- Frontier Economics
- GasNet
- Genesis Energy
- Goodman Fielder
- Greymouth Petroleum
- Major Electricity Users Group
- Major Gas Users Group
- Mercury Energy
- Meridian Energy
- Methanex
- New Zealand Energy Corporation
- Nova Energy
- New Zealand Steel
- NZ Sugar Company
- Oji Fibre Solutions
- OMV New Zealand
- Powerco
- Refining NZ
- Southern Fresh Foods
- Todd Corporation
- Transpower
- Trustpower
- Vector
- Wilmer International

Questions / submission template

Gas Market Settings Investigation 2021 **Submission prepared by:** <business name and contact>

Question		Comment
1	Do you agree with our characterisation of the role of gas in New Zealand?	
2	Do you have any comments in relation to the gas supply and demand outlook?	
3	Do you agree with our characterisation of the commercial outlook for gas?	
4	Have we captured the issues fairly and accurately? Have we missed anything?	
5	What are your views on the potential solutions stakeholders have raised? Can you share any more detailed information to help inform us on how feasible or effective they might (or might not) be?	
6	Are there any other potential solutions?	
7	Do you agree that there is potential in a set of solutions linked to providing greater confidence to support the required investment in gas supply and flexibility, and that there is unlikely to be a single solution?	
8	What are the most important next steps to ensure that gas can support security of supply in the electricity market and that major users have sufficient certainty/transparency about gas supply for their operations during the transition?	

Appendix: Background information

The New Zealand Gas Industry today

Gas industry structure

The New Zealand gas industry is isolated and, while gas is transported between international markets in other parts of the world by pipe or as LNG (liquefied natural gas), New Zealand does not have a natural gas importation capability, so is reliant on gas that is produced domestically.

New Zealand has a conventional gas industry structure, with an upstream exploration and production sector, and a downstream sector comprising high pressure (transmission) and lower pressure (distribution) transportation (pipelines) in the North Island, and wholesale and retail markets. Some large users, notably power stations, petrochemical producers, dairy factories and timber processing plants, are supplied directly from the high pressure transmission pipelines. Many of New Zealand's gas industry participants have interests at more than one level of the value chain.

Model for gas supply in New Zealand

The settings for the New Zealand gas industry contemplate a participant-led supply chain for gas, as shown in the following table.

Exploration & production	Natural gas supply is developed (and processed) if there is sufficient certainty of demand to underwrite the development of natural gas fields, which require significant and ongoing investment.
Processing	Processing facilities have been built in conjunction with the field development and are tailored to the field's characteristics. Third party access is governed by commercial contracts.
Storage	Up to 18PJ of gas can be stored in the Ahuroa underground storage facility to be used when needed.
Transmission	The main gas transmission pipelines are available to gas shippers under non-discriminatory, open access arrangements, and interconnection arrangements are in place to receive gas and to deliver gas to users.
Wholesale	The wholesale market is small and relatively concentrated, and competitive tendering for gas supply occurs. Wholesale trading is generally arranged bilaterally and on a confidential bases (with no publication of prices or terms). A commercial trading platform, emsTradepoint, was established in 2013 and provides a market-based transmission pipeline balancing regime as well as a small spot market for gas supply.

MAJOR USERS	Some large users (petrochemicals, large industry and electricity generators) contract directly with producers.
DISTRIBUTION	The gas distribution market is well established, with four open network services providers and one non-open access network owner. A formal downstream gas reconciliation regime provides an efficient process for allocating gas and levels of unaccounted-for gas are low.
RETAIL	Gas retailers manage their obligations to customers through various commercial and contractual mechanisms (e.g. rights to increase and decrease supply, to store produced gas, to interrupt gas supply in certain circumstances).

Statutory and regulatory framework

While participant led, New Zealand's gas industry is subject to a range of government policy and governance measures, which are designed to ensure gas is delivered to consumers in a safe, efficient, fair, reliable and environmentally sustainable manner.

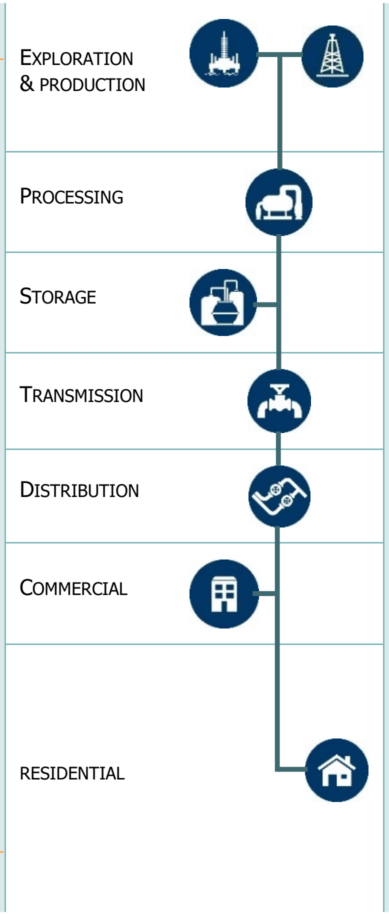
All aspects of the gas industry, from drilling exploratory wells to its production, transportation, sale and the installation of gas appliances in the home, are subject to a form of regulatory oversight. The governance regime involves a variety of regulatory bodies and continues to evolve. Identified issues in the mid-to-downstream sector are addressed through regulated and non-regulated solutions.

The **Gas Act 1992** provides for a Government Policy Statement (GPS) setting the objectives and outcomes for the industry body to pursue, includes various arrangements for the governance of the gas industry and mandates various gas safety requirements.

The **Commerce Act 1986** protects against the inappropriate exercise of market power or price fixing.

The **Health and Safety at Work Act 2015** provides a framework to secure the health and safety of workers and workplaces, along with more specific arrangements in the **Health and Safety in Employment (Petroleum Exploration and Extraction)** and **(Pipelines) Regulations** (2013 and 1999 respectively).

The **Hazardous Substances and New Organisms Act 1996** protects the environment, and health and safety, by preventing or managing the adverse effects of hazardous substances and new organisms, including gas as a flammable and potentially hazardous substance.



The **Crown Minerals Act 1991** governs the allocation of rights to, and the management of, gas. A permit is required to prospect, explore or mine gas.

Under the **Resource Management Act 1991**, gas fields and facilities and downstream infrastructure installations (e.g. processing plants, storage facilities and pipelines) require consents for their construction and ongoing operations.

A price-quality regime for gas transmission and distribution businesses under **Part 4 of the Commerce Act 1986** has been in place since 1 July 2013.

The **Gas (Critical Contingency Management) Regulations 2010** manage critical gas outages and other security of supply contingencies without compromising long-term security of supply, including the appointment of a Critical Contingency Operator.

The **Gas (Downstream Reconciliation) Rules 2008** set out processes to enable the fair, efficient, and reliable allocation and reconciliation of downstream gas quantities

The **Gas (Switching Arrangements) Rules 2008** enable consumers to easily switch retailers.

The **Gas Governance (Compliance) Regulations 2008** establish compliance processes and key compliance roles, including the Market Administrator, an Independent Investigator and a Rulings Panel, and allow for gas governance regulations and rules to be monitored and enforced.

The **Gas (Safety and Measurement) Regulations 2010** prescribe safety requirements for gas supply systems and certification of gas appliances.

The **Plumbers, Gasfitters and Drainlayers Act 2006** protects public safety by ensuring gasfitters are competent and regulating their services.

Gas installations must comply with the **Building Code**.

The **Fair Trading Act 1986** prohibits certain unfair conduct and practices in relation to trade, incl. protections against misleading and deceptive conduct.

The **Consumer Guarantees Act 1993** provides consumers with a guarantee as to an acceptable quality of reticulated gas (including safety and reliability).

Gas-Fired Electricity Generation Supply

Gas-fired generation provides around 13% of New Zealand's electricity, supplied from:

- Huntly (750MW from the Rankine units 1, 2 and 4, which can also be fuelled with coal; 385MW from unit 5; 48MW from unit 6, which can also be fuelled with diesel)
- Taranaki Combined Cycle (377MW, which will require major refurbishment soon as it reaches its operational hours limit)
- Stratford (210MW peaking)
- Junction Road (100MW peaking)
- McKee (100MW peaking)
- Mangahewa (9MW peaking).

Co-generation

Natural gas also contributes to electricity generation from cogeneration in New Zealand. Major industrial operators often use waste energy that may otherwise have been lost to improve efficiencies of operation. Cogeneration provides nearly 300MW of capacity at:

- Glenbrook (112MW, coal / gas waste heat and natural gas)
- Hawera / Whareora (68MW, heat recovery steam generation (HRSG) and natural gas)
- Te Rapa (44MW, HRSG and natural gas)
- Kinleith (39MW, wood waste and natural gas)
- Kapuni (25MW, waste gas and natural gas)
- Edgecumbe (10MW, waste gas and natural gas).

ABOUT GAS INDUSTRY COMPANY

Gas Industry Company is the gas industry body and co-regulator under the Gas Act. Its role is to:

- develop arrangements, including regulations where appropriate, which improve:
  - the operation of gas markets;
  - access to infrastructure; and
  - consumer outcomes;
- develop these arrangements with the principal objective to ensure that gas is delivered to existing and new customers in a safe, efficient, reliable, fair and environmentally sustainable manner; and
- oversee compliance with, and review such arrangements.

Gas Industry Company is required to have regard to the Government's policy objectives for the gas sector, and to report on the achievement of those objectives and on the state of the New Zealand gas industry.

SUBMISSIONS CLOSE:
4pm, Thursday 24 June 2021

SUBMIT TO:
www.gasindustry.co.nz

ENQUIRIES:
carolyn.vanleuven@gasindustry.co.nz