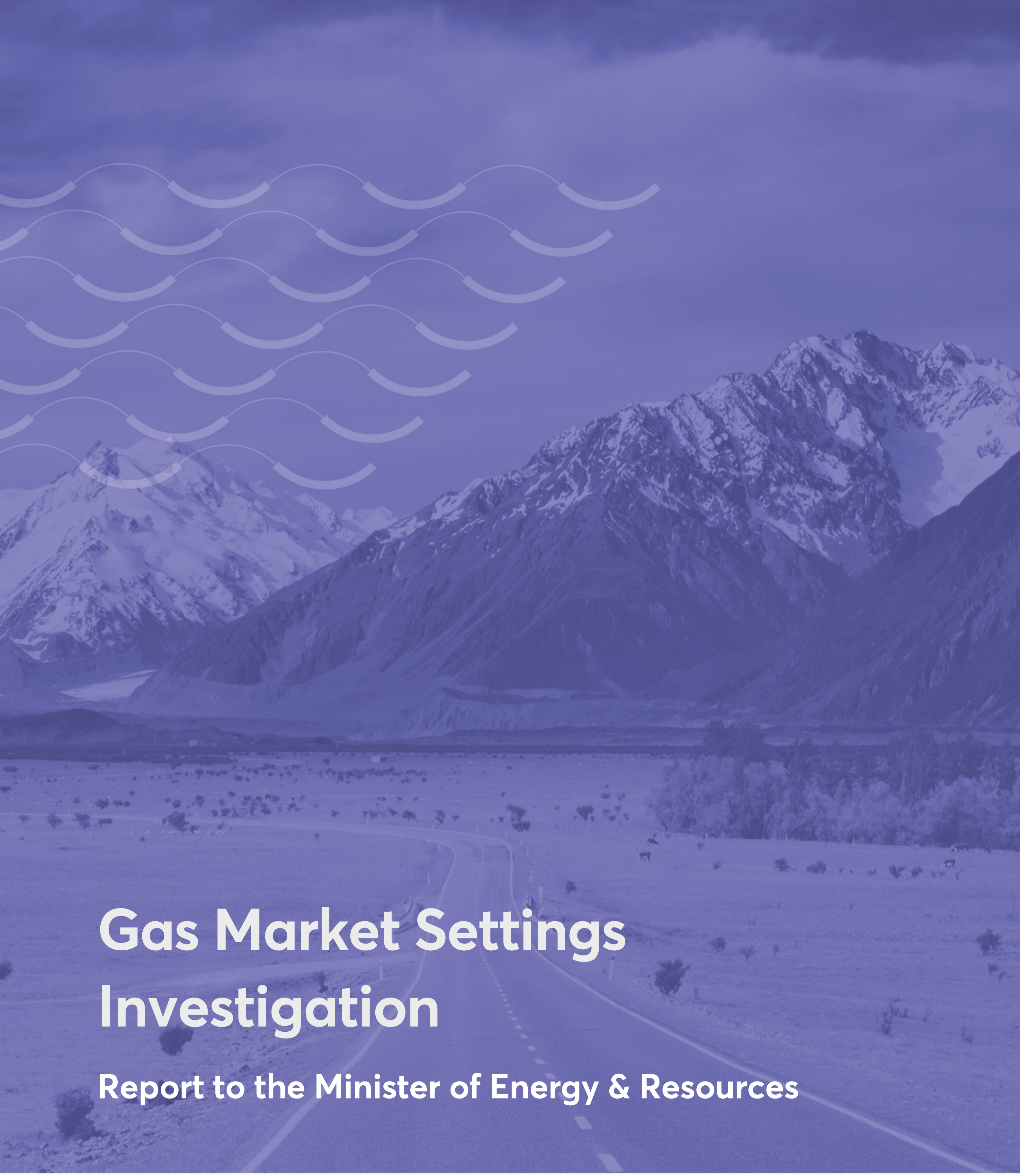


Gas Market Settings Investigation

Report to the Minister of Energy & Resources

30 September 2021

Gas Industry Co.

Executive summary

You have asked Gas Industry Co for advice on gas market settings 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.

You noted in your letter (a copy is included in Appendix 1) that you want 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 our advice, Gas Industry Co has investigated 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.

Our advice has been informed by the input we have received from various stakeholders, analysis we have conducted and commissioned, and feedback from consultation processes.

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 we hope that this investigation and our advice will play a part in helping identify steps to improve predictability and smooth the transition.

This report notes what a fit-for-purpose natural gas sector would look like; sets out some key aspects of the current arrangements; considers the outlook for natural gas in New Zealand (including developments in progress), and the issues that are arising and may get in the way of the transition; and recommends some potential solutions to the developing problem and a work programme to help us transition successfully.

Fit for purpose

Everyone we have heard from during this investigation acknowledges the need to decarbonise and is committed to a net zero carbon future. All agree we have to change – in Aotearoa and globally. Many are already making significant strides.

Our investigation has concluded that fit for purpose for the transition means:

- sufficient petrochemical/industrial demand remaining to support the required investment in gas development and production and to ensure the required minimum volumes of gas flow through the system during the transition so that natural gas is available:
    - to support electricity generation until no longer required (the current assumption is that this will be until 2030, given the Government's 100% renewable electricity target, but with some leeway to extend if required)
    - to supply users who need to keep operating in New Zealand to support our economy and society and have no suitable alternative energy supply, or until an alternative becomes achievable
    - to 'mass market' users including commercial, residential and agricultural operations, albeit at reduced volumes over time

- a smaller role for natural gas as more renewable electricity comes on stream and alternative energy sources are developed for direct gas users
- some users exiting as their businesses become less viable, partly due to availability and cost of suitable energy.

Key aspects of current gas industry arrangements

Some technical aspects of gas field development, maintaining production, and specific characteristics of different well/reservoir types impact the deliverability of New Zealand's gas supply, and limit the way the sector can operate.

Gas reserves (including '2P' reserves that producers have a relatively high degree of confidence in being able to produce) can only be recovered, delivered and eventually consumed if ongoing investment is made (with average required investment across Taranaki fields estimated to be in the order of $200 million a year). Gas demand and supply in the period from 2025 to 2030 will be strongly influenced by decisions that are being made now. Whether gas is available for all users depends on producers' willingness to invest in supply-side assets.

In turn, field operators' willingness to invest in gas development and production depends on pre-contracted demand for their gas because of the large financial and lengthy time commitments involved. Decisions on the type of and scope of development that will shape the field's ability to produce gas throughout its producing life are made early on in the development cycle. Producers and large-scale users alike cannot depend on the gas 'spot' market, which is very limited in New Zealand, carrying around 4% of trades and unlikely to materially increase given it cannot provide the required certainty of demand to underpin investment (nor the certainty of supply to meet long-term, large-volume demand).

It is often stated that there are "ten years of gas in the ground" as an approximation of gas remaining for consumption – this is a shorthand calculation of how long current rates of consumption could continue to be met from known 2P gas reserves. These reserves can only be recovered, delivered and eventually consumed if ongoing investment is made as planned, and therefore should not be thought of as equivalent to gas in storage ready to be consumed. It may be more helpful to think of the 10 years as a bow wave of the potential level of gas reserves that producers are relatively confident of being able to recover in the coming years. This bow wave is maintained by the exploration and appraisal activities of upstream gas parties. These bring resources that were previously considered only 'contingent' into the assessment of 2P reserves as those 2P reserves move through the maturing, delivery and consumption cycle.

Because of the way natural gas is found, developed and delivered to customers, there is inherent uncertainty throughout the development timeframe and at every step of the production process. Most capital for investment in ongoing field development competes with alternative capital allocation globally, in which estimated returns are discounted against technical, commercial and above ground risks for the particular development.

Producers have some limited ability to adjust their level of production in a gas field once operational, but only within certain limits. This means it is difficult to significantly alter production rates in a field on a short-term basis, and consequently, production is not incentivised by short-term price signals. Storage can provide a degree of flexibility if it is filled in advance of need.

Outlook

A range of views of the outlook for natural gas in New Zealand have been modelled in recent years, which could represent equally possible futures. As part of this investigation, we commissioned supporting analysis on the gas supply and demand outlook over the period to 2035 from Concept Consulting, which we have used as our base.

While there are differences between various organisations' modelled outlooks, all see significantly reduced demand for natural gas in New Zealand as the transition progresses and some natural gas remaining in our mix in 2050. Estimates are between 50 PJ and 110 PJ remaining in 2035 and between 26 PJ and 50 PJ in 2050. We have assumed that natural gas will not be used as fuel for electricity generation beyond 2030 (which is a different approach than most modelled scenarios), but that it will be needed for some petrochemical, industrial, commercial, agricultural and residential use for longer.

Supply of natural gas will likely be tight next winter and possibly into 2023, but investment is occurring. With industry coordination, and continued investment and good risk management across the energy sector, gas supply should be able to be managed to meet demand in the short to medium term.

There is more confidence that tight conditions will ease by 2024, provided investment in development and production continues. This is especially in light of recent successful investments in production, and an expectation that planned work programmes at all major New Zealand gas fields will see more gas being brought to market. In addition, committed new renewable electricity generation projects are expected to be on stream, reducing thermal generation demand for gas. Together these are likely to lift supply available to other gas users by around 30-45 PJ per year by 2024. In addition, if the Tiwai smelter closes at the end of 2024, that will further reduce demand for gas to generate electricity.

Importantly, though, gas reserves still require ongoing investment to be developed, a point which is expanded on later in this report.

In the longer term, our expectation is that Methanex will remain in New Zealand and continue to support production investment, and therefore natural gas reserves will be developed. This provides confidence that natural gas will be available to support electricity generation and major users (along with the residential, commercial and agricultural 'mass market') through the transition to 2030 and beyond.

In addition, for natural gas to be able to play its part in supporting security of supply in the electricity sector until other sources of energy become available (currently targeted for 2030):

- thermal electricity generating plant needs to remain available for use during the transition
- gas supply for electricity generation needs to be more flexible to enable remaining thermal generating plant to operate in an increasingly variable manner as more electricity demand is met by weather-dependent renewables and volumes of thermal generation reduce
- investment in gas development and production needs to be committed well before demand requires the supply, given the time lag between investment commitment and production.

What is the problem?

Despite the outlook showing there are sufficient reserves in the ground to meet New Zealand's gas demand, without ongoing investment well in advance of when the gas is needed, there is a real risk that not enough gas will be able to be delivered to major gas users, including electricity generators, during the transition out to 2030 and beyond.

We have identified two key problems that need priority attention in order to enable natural gas to play its part in the transition.

1 Capital investment

We have heard that there is a higher risk hurdle for capital investment in gas production and development in New Zealand than has previously been the case. While investment is happening now, future capital investment is at risk and a higher risk premium is being attached to any investment to compensate. We consider that this leads to a real risk that insufficient investment will be committed to ensure that gas reserves and contingent resources will come to market and that security of supply for both electricity generation and major users could therefore be compromised during the transition to 2030 and beyond.

In relation to the gas development and production investment that New Zealand needs during the transition, there are three key factors that put it at the high-risk end of the spectrum and contribute to difficulties in committing the capital required:

- Demand for gas (and therefore investment into gas development and production) is affected by concerns about businesses or industries shutting down or becoming uneconomic, a lack of clarity about the expected timing and balance between reduced gas use and overall decarbonisation for major gas users, and a lack of confidence that gas supply will be available to meet this demand.
- There are fewer opportunities to manage risk as the size of the industry decreases during the transition (e.g. reduced opportunity for diversification and fewer parties willing and available to share risk).
- Investors (in both production and demand) understand and expect that the policy and regulatory levers that will inevitably be pulled through a transition will change the economics of their investments, but are unsure to what extent. This includes changes in both the energy and broader environmental and social context – including, for example, resource management reforms impacting demand.

Participants acknowledge that the high-level overall desired direction for New Zealand's energy and broader carbon transition is clear. However, the timing and extent of the transition for natural gas and the pathway to achieve the overall goals are not so clear and we do not expect currently announced strategy and policy developments to give us the required confidence that sufficient and timely investment will occur.

2 Commercial arrangements for gas to support electricity in dry years

In addition, this investigation has identified that there are insufficient commercial arrangements for gas supply dedicated in advance for electricity security of supply during sustained dry periods. Current committed arrangements do not appear to be sufficient to cover the large volume of thermal fuel support required for dry winters over the transition period. In 2021 participants have had to rely on last-minute contracting when it appeared a 'dry winter' was looming, creating unplanned demand diversion from gas users who are unable to absorb the reductions in their operations and resulting in poor overall outcomes for New Zealand.

Key actions

We consider that two key action areas could address the key problems outlined.

1 Gas Transition Pathway

First, we recommend that a workstream be established to develop a Gas Transition Pathway to provide the granular direction needed to support improved investment confidence. This could be jointly managed by Gas Industry Co and the Ministry of Business, Innovation and Employment (MBIE) and should involve input from industry and a range of stakeholders. We would see this work feeding into a broader Energy Strategy in time, and enabling early focus in an area where it is needed (given the strategies for electricity and coal are relatively clear).

A critical part of this pathway would be considering how to ensure there is continued commercial support for production investment during the transition. For example, it will be important to develop a universal (cross-government) understanding of the factors that will drive petrochemical businesses' decisions about whether to remain operating in New Zealand, so they can play their critical role in supporting and enabling the transition.

2 Improving commercial arrangements supporting electricity security of supply

Secondly, we also recommend a set of three interrelated workstreams to improve commercial arrangements so that sufficient volume and flexibility of gas supply is in place far enough in advance to promote security of supply for electricity (covering both energy and capacity).

This should in turn provide increased predictability for major gas users' operations, since they will be less likely to experience such extreme pricing volatility as we have seen in 2021 or unplanned curtailments to their gas supply.

Arrangements are needed specifically for the electricity generation sector (rather than other major users), given it is generators' operations that need the volumes of flexible thermal fuel supply to counteract intermittent renewables.

A Supply side

In the first of these, Gas Industry Co would focus on what gas producers and major users have agreed to/can deliver to generators and major users over the medium to long term, including:

- carrying out more regular gas supply and demand studies and identifying gaps
- assessing the likely costs and availability of gas-related options (including storage, assuming supply is available to fill it; planned demand response arrangements; and unplanned demand diversion) to support electricity security of supply
- potentially facilitating arrangements between industry participants where necessary.

Commitments are essential some years in advance, given the timeframes for investment to bring gas reserves into production.

B Planned demand response

Alongside gas storage, planned demand response by Methanex is likely to be readily available and at large enough volumes to enable the flexibility in the system needed to provide the security of supply required. In the medium to longer term as the transition progresses, large-scale planned demand response can support security of supply without the challenges of finding additional gas to fill storage or of developing a new LNG import industry for New Zealand.

The second proposed workstream in this set therefore recognises the criticality of Methanex's role.

A critical early step will be Gas Industry Co facilitating discussion between relevant stakeholders (e.g. Methanex, Genesis, MBIE, consenting authorities, the Electricity Authority) to develop a specific understanding of the factors that will influence Methanex's decisions around whether to remain operating in New Zealand as it transitions, given its role.

A key focus will be on the appropriate commercial arrangements to underpin any planned demand response, how these are enabled and who ultimately pays.

C Reviews of electricity market operation and competition

Lastly, we anticipate that the Electricity Authority will consider issues relating to thermal fuel availability for electricity generation (including current limitations to backup fuel supply for sustained dry periods) in its reviews of:

- the electricity industry's management of the 2021 dry hydro sequence and tight gas market
- the events of 9 August 2021 (the Phase 2 review)
- electricity wholesale market competition.

The first of these reviews in particular is expected to include consideration of arrangements for fuel supply (both gas and coal) to support thermal generation in future sustained dry periods, informed by recent experience of (and current limitations to) these arrangements.

Other workstreams

In addition to these two key areas of focus, we consider that dedicated workstreams in relation to the following are needed to improve the operation of the gas sector during the transition:

1. **Information availability** to help enable participants and users to predict and plan better (with a number of actions in addition to key action area 2 above)
2. **The regulatory framework for gas pipelines**, including joint work by MBIE, the Commerce Commission and Gas Industry Co on both:
    - the current Part 4 Commerce Act framework and tools
    - whether changes are needed to the overall regime.
3. **How gas can support New Zealand's energy needs that cannot be met by electricity, including:**
    - the (potentially accelerated) development of 'green gases' including hydrogen and biofuels
    - how to avoid and reduce emissions for those who need to use gas
    - exploring the viability of emissions capture and storage in New Zealand.
4. **Considering whether additional mechanisms are desirable** to ensure gas is available to industrial users in unexpected tight situations, as we have seen in 2021.

Our planned work programme covering the key actions and the other workstreams is set out in Appendix 2.

Contents

1 Introduction and Purpose

This report notes what a fit-for-purpose natural gas sector would look like; sets out some key aspects of the current arrangements; considers the outlook for natural gas in New Zealand, developments in progress, and the issues that are arising and may get in the way of the transition; and recommends some potential solutions to the developing problem and a work programme to help us get there.

You have asked Gas Industry Co for advice on gas market settings 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. You noted that you want 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 our advice, Gas Industry Co has investigated 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.

Our advice has been informed by the input we have received from various stakeholders, analysis we have commissioned and conducted, and feedback from consultation processes.

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 Co intends that this investigation will play a part in helping identify steps to improve predictability and smooth the transition.

Gas Industry Co has:

- had conversations with 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. We have learned a lot from those conversations and we are grateful for the thoughtful input
- 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 or LNG could support and/or complement natural gas supply during the transition period
- issued, and analysed responses to, a consultation paper.[1]

[1] See https://www.gasindustry.co.nz/work-programmes/gas-market-settings-investigation/developing-2/consultation-3/

2 What is fit for purpose for the transition?

To be able to advise on whether settings are fit for purpose for the transition, we asked and considered what 'fit for purpose' looks like. This section sets out what our investigation has concluded fit for purpose for the transition means.

Section 2 summary

Fit for purpose for the transition means:

- sufficient petrochemical/industrial demand remaining to support the required investment in natural gas development and production and to ensure the required minimum volumes of gas flow through the system during the transition so that natural gas is available:
  - to support electricity generation until no longer required (current assumption is 2030, but with some leeway to extend if required)
  - to supply users who need to keep operating in New Zealand to support our economy and society and have no suitable alternative energy supply, or until an alternative becomes achievable
  - to supply commercial, residential and agricultural consumers
- a smaller role for natural gas as more renewable electricity comes on stream and alternative energy sources are developed for direct gas users
- some users exiting as their businesses become less viable, partly due to availability and cost of suitable energy.

2.1 How will natural gas use change during the transition?

Everyone we have heard from during this investigation acknowledges the need to decarbonise and is committed to a net zero carbon future. All agree we have to change – in Aotearoa and globally – and many are already making significant strides. During the transition we expect:

- Natural gas use will continue to decrease, albeit that it will be needed to some degree for years to come, as recognised in a range of studies and forecasts of future energy use in New Zealand, including the Climate Change Commission (see section 4 below)
- Many natural gas users will divert to electricity and some to other renewable sources such as woody biomass
- Some natural gas users who need the specific properties of gas (e.g. higher, more instantaneous, controllable heat than electricity can provide; use of gas's by-products like CO_2) may divert to green gases (biogas and hydrogen) as they become more readily available

- The commercial, residential and agricultural 'mass market' will continue to rely on gas during the transition, albeit at declining volumes over time
- Some natural gas users will cease operations or leave New Zealand, if either continued use of natural gas or swapping to alternatives is not viable.

Like with any transition, there will be uncertainty for a time, which needs to be expected, assessed and planned for.

2.2 The role of natural gas during the transition

Natural gas continues to play a vital role in supporting electricity generation. As new renewable electricity projects are developed and come on line, the overall volumes of gas needed to fuel electricity generation will decrease (despite a forecast increase in overall electricity demand).

However, natural gas will be needed as a source of back up energy to provide security of fuel supply for electricity, both during sustained dry periods ('dry winters') and for year-round peak demand (likely alongside coal for a period) and this need is likely to become increasingly variable. This will continue until the NZ Battery Project comes on line (currently targeted for 2030) or another source of back up energy (potentially including planned demand response) becomes available.

Major gas users, including in critical industries, will continue to rely on natural gas as a source of energy for direct use and co-generation well beyond 2030. This is despite a gradual reduction in demand due to increasing energy efficiency and a move toward lower emission fuel sources where they can meet users' requirements. In some cases, current and anticipated alternatives are not suitable for physical, technical, practical or economic reasons, and may even result in poorer emissions or environmental outcomes. Technology and/or economics may enable phase out of natural gas in time, however, e.g. if hydrogen is developed at scale in New Zealand or imported.

Some commercial, residential and agricultural 'mass market' customers will also continue to rely on natural gas during the transition. Restaurants rely on gas for cooking as it provides immediate high temperature heat that currently cannot be provided by electric or induction cooktops. Gas dryers used in laundromats reduce drying time and costs over time due to the rapid and high temperature heat that is provided. The cost of operating these driers is less than half of the cost to operate a machine powered by electricity. Patrons of these facilities typically live in high density housing without options for drying laundry outside and are often affected by hardship.

As noted in the NZ Gas Infrastructure Future Working Group's Findings Report:

> *"The most significant issue identified is the likely need for significant investment in additional electricity distribution capacity in certain parts of relevant networks to enable electricity to substitute for gas. This is likely to be a significant issue for electricity networks that service consumers that currently use gas for heating and cooking during peak times, such as early evening. For instance, converting all of Wellington's natural gas use across to electricity could add 200–300MW to Wellington Electricity's peak load and require $380–575 million in network upgrades. A similar order of magnitude is expected for Auckland."*[2]

Natural gas can also help to reduce New Zealand's emissions profile during the transition where it displaces or enables quicker switching away from higher-emission fuels like coal or enables improved efficiencies. For example:

- with sufficient gas supply to fuel electricity generation plant, there would be less call on the Huntly power plant to burn coal to meet electricity demand
- continued availability of gas enables major users like Fonterra to focus their efforts on phasing out the use of coal boilers more quickly (see the case study below for further information on this).

[2] See para F64 on page 8 of the Working Group's *Findings Report*, 13 August 2021, which refers to Wellington Electricity's submission to the Climate Change Commission: *Re: Draft Advice for Consultation – meeting the Climate Change Commission's proposed emissions budgets*, page 6

Case Study: Fonterra

Fonterra is a co-operative of 10,000 New Zealand farmers which operates 27 manufacturing sites throughout New Zealand. Sixteen of these sites use natural gas, with a total of 76 gas boilers and air heaters that use gas to produce heat for processing milk. Nine of the sites use coal as a primary source of energy, seven of which are located in the South Island where natural gas is not reticulated. Some sites have co-generation, which enables them to also generate electricity from the otherwise unutilised waste heat.

Fonterra has clear decarbonisation goals throughout its business, relating to its emissions from agriculture, transport and process heat. With regards to the latter, Fonterra has committed to not installing any new coal boilers and to ending its coal use by 2037 to meet the Climate Change Commission's goal to end industrial coal use by then. Once it has eliminated coal use, Fonterra then plans to phase out of natural gas from 2037. It has prioritised the conversion of coal boilers over gas given their much higher carbon footprint and lower efficiency.

Fonterra 's current decarbonisation activities are transitioning from coal to wood biomass. To date, Fonterra has modified its Brightwater site to co-fire wood biomass with coal, converted the coal boiler at its Te Awamutu site to operate on wood pellets, and recently announced it is building a new wood biomass boiler at its Stirling site to replace the coal boiler.

Fonterra has raised concerns that, without confidence in secure gas supply, it may need to start transitioning its gas boilers and air heaters to renewable alternatives sooner than 2037, which would almost certainly impact the speed at which it could transition off coal, because:

- only a limited number of biomass boilers can be manufactured to its specifications each year – there is increasing domestic and international demand for boiler construction and installation
- it needs to ensure there is sufficient milk processing capacity operational during the peak milking season, restricting the number of plants that can be out of action at any one time, particularly between August and November when 85-90 million litres of milk are processed per day.

On the other hand, if Fonterra has confidence in secure gas supply during the transition to net zero carbon by 2050, it will be able to continue to prioritise phasing out its highest-emissions, lowest-efficiency plant first, resulting in significantly lower emissions from its energy use during the transition.

2.3 What is required to ensure those needs can be met?

As discussed in section 3.1.3 below, because of the way New Zealand's gas fields and industry operate and the capital intensive nature of gas development, ongoing investment is required in order for gas to be available to meet these needs.

In addition a minimum flow of gas is required:

- at a field level to maintain production above lower limits, both to enable the plant to operate at all and to avoid damage to the producing sites (see section 3.4.1 below)
- at a system level to cover fixed costs (e.g. staff, external costs for running infrastructure) and to ensure it is economic to continue maintaining the pipelines (see the end of section 3.1.3 below).

Long-term, baseload, large-volume (cornerstone) gas contracts are crucial for all of these factors, since they:

- provide the certainty of demand needed for producers to commit to funding development
- ensure sufficient levels of gas demand remain in the system
- enable the required flexibility in the system as some users (notably Methanex) can adjust their level of gas demand to counterbalance the potential variation in gas supply needed to support electricity demand due to unpredictable hydrology.

Petrochemicals (and Methanex in particular) are the only industry sector large enough to be able to play this role to support the rest of the energy sector. Their ongoing operation is therefore critical to ensure natural gas can play its part in the energy transition.

We discuss our more detailed recommendations for what is needed in section 6 below.

3 Key aspects of current arrangements

Part of the brief for this report was to set out current arrangements in the New Zealand gas sector. In this section we have focused on four key aspects of current arrangements in the New Zealand gas sector that tend to not be well understood. A summary of current arrangements more generally is set out in Appendix 3, including the gas industry structure, the model for gas supply in New Zealand, the statutory and regulatory framework and a list of gas-fired electricity generation.

Section 3 summary

Some technical aspects of gas field development, maintaining production, and specific characteristics of different well/reservoir types impact the deliverability of New Zealand's gas supply, and limit the way the sector can operate.

2P reserves can only be matured, delivered and eventually consumed if ongoing investment is made (with required investment across Taranaki fields estimated to be in the order of $200 million a year). Ongoing investment decisions need to be made today to ensure deliverability of gas in the mid to late 2020s, and even into the 2030's.

Field operators need to contract demand for their gas before investing in development and production because of the large financial and lengthy time commitments involved, and because decisions on the type and scope of development made in early in the development cycle will shape the production of gas throughout a field's producing life.

There is a very limited gas spot market carrying around 4% of trades, which is unlikely to increase given it cannot provide the required certainty of demand to underpin investment (nor the certainty of supply to meet long-term, large-volume demand).

The 2P (or P50) reserves commonly reported are the estimated volume of hydrocarbons that have a 50% chance of being equalled or exceeded (or conversely, of falling below that estimate). Confidence in the figure declines with the number of producing fields, with an increased likelihood of variation from the 2P number in either direction.

Because of the way natural gas is found, developed and delivered to customers, there is inherent uncertainty throughout the development timeframe and at every step of the process. Most capital for investment in field development competes with alternative capital allocation globally, in which estimated returns are discounted against technical, commercial and above ground risks.

Producers have some limited ability to adjust their level of production in a gas field, but only within certain limits. This means it is difficult to significantly alter production rates in a field on a short-term basis, and consequently, production is not highly responsive to short-term price signals.

Storage can provide some flexibility.

3.1 Getting gas out from 'in the ground'

The current arrangements in the New Zealand gas sector are shaped by the nature of natural gas development and operation. Some technical aspects of gas field development, maintaining production, and specific characteristics of different well/reservoir types impact the deliverability of New Zealand's gas supply, and limit the way the sector can operate.

3.1.1 Development of a gas field

While there is no one fixed path in the development of a gas field, the full lifecycle of discovery of a new gas field through to initial production can take in the order of 5+ years (for onshore) to 10 years or much longer (for offshore) from beginning to end, although there is a wide variation in development times depending on specific technical and non-technical circumstances. In New Zealand we have seen developments taking as little as a year and as long as 40 years. Offshore developments normally take longer due to the need for more complex (and expensive) drilling rigs that have a long lead time to secure, as well as additional engineering and logistical challenges. At one end of the spectrum, the Kupe field did not enter production until 23 years after discovery, largely given it was not commercially viable until the dominant Maui field entered its decline phase in the early 2000s. At the other end, the offshore (but close to shore) Pohokura field was a record for offshore developments at 6 years between discovery and first gas being produced.

For development of additional reserves within an existing producing field, many of the steps set out below can either be skipped or significantly shortened in duration. For example, it would be possible in some situations to identify and execute a drilling opportunity for an onshore well in an existing field in less than a year if a drilling rig is already in-country and quickly available. The timeframe for development depends on how much activity is required in each of the stages, and whether some stages can be skipped entirely.

The typical steps that would be followed in developing a gas field are outlined below.

Prospecting

Before any exploration wells are drilled, it is typical to identify potential drilling prospects through geological surveys. The most well-known of these are seismic surveys, but there are also other less expensive surveys that are sometimes conducted before the cost of a seismic acquisition campaign is justified. The equipment necessary for such surveys would normally need to be mobilised from overseas. After physically acquiring survey data, it can take many months (approximately 1.5 years) to process and interpret the data.

Exploration and appraisal

Over the next 2-10 years after the prospecting phase, a decision may be taken to drill one or more exploration wells to determine the size, quality and extent of the geological area of hydrocarbon accumulation, known as a 'play'. Onshore exploration drilling could be conducted with available onshore drilling rigs in New Zealand, but offshore exploration will always require a rig to be mobilised from overseas. Sometimes it will be possible to contract for the drilling rig in such a way that if the exploration well is successful, the drilling rig is already on standby to drill an appraisal well (see below). At other times however this cannot be arranged (for economic or other reasons), and the drilling rig will depart the country after the exploration well is drilled. This means another rig would need to be mobilised to conduct any appraisal drilling.

After a discovery is made, the size of the gas field is usually not well understood from a single 'pinpoint' entry into the field, and appraisal drilling is needed (sometimes several appraisal wells are drilled in a variety of locations to test the potential boundaries of the field) to better understand how large the accumulation is. The other key data acquired during appraisal is samples of the gas/liquids in the reservoir to determine what size and type of processing facilities are needed. If there is no gas, or if the site is not commercially viable, the wells are plugged and abandoned.

Development

The development of a discovery can take 3-10 years after the size and nature of the subsurface resource has been identified. Further studies are carried out confirming the economic viability of the project, and selecting and designing the overall development concept. This will include making decisions on how many wells to drill, what type of wells, what size of surface processing facilities and location (offshore versus onshore processing), what products to produce (e.g. whether to extract LPG or not) among other things. These decisions will affect the level of production the field will be able to operate at over its producing life and so rely on a producer's estimate of how much it will be able to sell. In New Zealand this is dependent on known demand (see section 3.2 below).

Also during this phase regulatory requirements will be fulfilled, health and safety and environmental assessments will be undertaken, stakeholders will be engaged, and the economics of the project will be assessed. When everything is ready a 'final investment decision' can be taken.

A field will be developed if it is technically and commercially viable, taking a range of risks into account (see section 3.3.3 below). Construction activities following a final investment decision will involve several key activities, including the construction of surface facilities and the drilling of the development wells. Plans are approved by government and regulatory authorities, and implementation is carefully monitored. Stakeholders are engaged with to consider environmental, social, economic and operational issues.

Production

Once a field is developed, it will typically produce gas for the next 20-50 years. Every field has its own characteristics which require bespoke production concepts, but ongoing development of the field is carried out through the drilling of further wells, the installation of new pipelines, facilities and compression in the most cost-effective way in order to meet future gas market requirements, and with regard for the environment and local communities that may be impacted. Some of these types of ongoing development are further discussed in section 3.1.3 below.

The 'decline phase'

Once in production, a field will produce at a maximum rate (known as 'plateau production') for a number of years, and then enter the 'decline phase'. This decline phase can last for decades, depending upon the size of the gas field. New Zealand's producing gas fields are in the decline phase and require step out drilling of new wells or other investment to maintain production and slow the decline.

Based on future gas demand market forecasts, field operators replace declining production by investing in further field development to bring reserves into production and/or undertake further appraisal of the field's potential (including of 'contingent' resources) to ensure that demand can be met.

Depletion compression investments at Pohokura and Kupe

The depletion compression investments made at each of Pohokura and Kupe are each textbook examples of the type of investments that tend to be made once a field exits plateau. Each project cost ~$70m with each one important as underpinning forward gas deliverability.

Without the inlet compressor, production from Pohokura would be 35 TJ per day less than what it now is. Kupe will add 15 TJ per day when its compressor is commissioned later this month. Together those compressors serve to add deliverability equivalent in scale to a little under the gas volume required to fuel the Taranaki Combined Cycle unit operating at full capacity.

Decommissioning

When production from a field ceases, facilities are decommissioned and the location is remediated, taking approximately 3-10 years to complete.

3.1.2 Characteristics of different well/reservoir types

It is the difference in pressure between the gas reservoir (high pressure) and surface facilities (lower pressure) that provides the energy needed to bring the gas (and any liquids) to the surface. The two main types of pressure mechanism in gas fields (which also can be seen as book-ends) are 'water drive' and 'depletion drive'.

In the case of a water drive, the aquifer underneath the gas in the reservoir pushes the gas upwards, and as the gas is depleted from the reservoir the liquid follows by filling the space previously occupied by gas, thereby continuing to push the remaining gas upwards. This is analogous to a piston, and the pressure in the reservoir tends to remain fairly high during the life of the reservoir.

With a depletion drive, the aquifer strength is lower, and liquid does not follow the gas upwards in the reservoir as the gas is depleted. In this case the pressure in the reservoir is initially high, but decreases over time as more and more gas is produced. This is analagous to letting air out of a balloon, where the air initially comes out quickly but slows as the pressure in the balloon reduces.

Wells that produce from a strong 'water drive' reservoir (such as the bulk of Maui's historical production) typically have the ability to produce at a very high rate when called upon to do so. However, care is needed to not produce at too high rates for too long, as this can result in emptying the area nearby that well of gas and drawing the liquid into the well. This is known as 'watering out' of the well. Prudent management of production rates allows the gas from a much wider lateral extent of the reservoir to be produced through that well, with the rise in water level across the field being more even. Over time, the maximum prudent rate any particular well can be produced at may reduce as that part of the reservoir well gets closer to being depleted and the water gets closer to the well.

The maximum rate of production from a well in a 'depletion drive' reservoir tends to decline as more gas is produced from the field.

Even where reservoirs are managed prudently, it is common for gas producing wells to begin producing this liquid as the reservoir (or the relevant part of the reservoir) is depleted. In this situation, producers will then need to balance further considerations so that the production rate in the well is:

i. sufficient to keep the fluid velocities in the well high enough to 'lift' the liquid to surface, but

ii. not so high as to bring much higher quantities of liquid into the well thereby 'watering out' the well entirely.

When wells at this stage in a field's life are shut in, liquid from the aquifer can build up in the well and nearby parts of the reservoir over time to the point where it cannot be restarted.

As individual wells get close to the end of their life, they sometimes need to be operated as essentially 'on' or 'off' wells; it is not prudent to attempt to flow them at anything less than maximum rates (due to water build-up in the wells and the risk of watering out entirely).

3.1.3 Ongoing investment required to maintain gas deliverability

It is often stated that there are "ten years of gas in the ground" as an approximation of gas remaining for consumption. This timeframe is calculated as how long current rates of consumption could be met from known gas reserves, which producers have a relatively high degree of confidence in being able to recover (known as '2P' reserves – see section 3.3.1 below for more on these and other natural gas reserve / resource classifications). But this approximation does not account for:

- the dynamics of gas development and production, such as the impact of deliverability decline on the production of 2P reserves (see above for more on the 'decline phase')
- investment that is required to bring the gas to market (with the ongoing investment required to bring reserves into production having been estimated by Enerlytica to be in the order of $200 million a year averaged across all Taranaki fields) or the likelihood of that investment being made
- the long production 'tail' to most wells.

The 2P reserves can only be recovered, delivered and eventually consumed if ongoing investment is made as planned, and therefore should not be thought of as equivalent to natural gas in storage ready to be consumed. Development that can unlock 2P reserves can include installing compression, drilling new wells into different but known reservoirs, or drilling infill wells into existing reservoirs and between existing wells, to increase both production rate and reserve recovery.

For example, reserves at Maui B are classed as 2P because an in principle commitment has been made to develop them and the field's owners are reasonably confident they will be able to deliver them, but wells need to be drilled (at considerable expense) in order to recover those reserves.

In relation to the third point, field operators are limited in their ability to control the rate at which reserves are extracted, with that rate becoming slower as a field declines. The "ten year" figure is a result of dividing the total reserves by current consumption, and we heard from producers that it is often more likely to take 20 years for that volume of gas to be extracted.

It may therefore be more helpful to think of the 10 years as a bow wave of the potential level of production of known reserves that producers are relatively confident of being able to recover in the coming years. This bow wave is maintained by the exploration and appraisal activities of upstream gas parties, which bring resources that were previously considered only 'contingent' into the assessment of 2P reserves as those 2P reserves are matured, delivered and consumed. Known 2P reserves are also constantly being revised as new drilling locations are investigated, and the performance of existing fields becomes better understood.

As New Zealand's gas fields are in the decline phase, ongoing investment decisions need to be made today to ensure deliverability of gas in the mid to late 2020s, and even into the 2030's.

Mangahewa investment-led maturation

In January 2012 on the signing of a long-term Gas Supply Agreement with Methanex, Mangahewa field operator Todd Energy stated that it was aiming to mature 450 PJ of contingent (2C) resource[3] into reserves status. At that time remaining 2P reserves were reported as 181 PJ.

Over the following nine years, investment included the drilling of 24 new development wells, a new gas plant and an extensive network of above-ground gathering pipelines, for what Enerlytica estimates would have been a total cost approaching $1 billion. This investment added 484 PJ of 2P reserves.

As at January 2021, Todd Energy reported 2C contingent resources of 1,208 PJ, on top of the 727 PJ of gas to have been produced and/or promoted to 2P status since 2012. Only a subset of this is likely to be producible, but the success of the development from 2012-2021 gives reason for optimism.

Promoting these 2C resources to 2P reserves status will require another very large investment programme. Todd Energy has indicated it will drill up to 24 further development wells from its Mangahewa C and D wellsites over the next 10 years. While the new wells will make extensive use of existing production infrastructure, Enerlytica estimates the investment required will likely approximate $500m.

Remediation

At varying times within the lifecycle of a producing hydrocarbon well, there will be a need for 'intervention' work to be performed. An intervention in a well can involve any number of activities, that could include for example:

- mechanical repairs to the safety valves inside the well
- drilling (or 'milling') out a build-up of scale inside the well tubing (which otherwise constrains/blocks the flow of gas)
- sealing off the points of connection between one part of the gas reservoir and the well tubing (which would typically be done, for example, when that part of the reservoir has stopped producing gas but has instead started producing the liquid from the aquifer, in order to stop/reduce the liquid flow to the surface – a so-called 'water shut-off').

For example Maui with its water drive required few and simple production wells. In contrast to this, Mangahewa with its deep, tight reservoir rock requires a much more intensive development programme with large numbers of development wells drilled on an ongoing basis to sustain production with extensive stimulation programmes. There is no single recipe.

Depending on the nature of the activity to be performed, a variety of different methods to access the well tubing may need to be used. Some activities can be performed via a 'wireline', where the tools and equipment needed for the job inside the well can be lowered into the well on the end of a wire. This is normally relatively cheap and quicker than alternatives. At the other end of the spectrum, some of the activities would require a full drilling rig (which comes with much higher cost and space considerations) to be used. In between these two scenarios in terms of cost and ease, there are other methods that can be used to access the well tubing to perform the

[3] 'Contingent resources' are potentially recoverable from known accumulations by application of development projects but not currently considered to be commercially recoverable, with low/best/high estimates denoted as 1C/2C/3C respectively.

necessary work, such as 'coiled tubing' operations where a continuous length of flexible small-diameter steel pipe is used to access the well.

Offshore gas production facilities do not normally retain drilling rigs or coiled tubing units permanently 'onboard', given the value and cost of maintaining such expensive facilities for occasional use. Therefore, when well intervention activities are to be performed, the required equipment needs to be mobilised specifically for the job. In the case of drilling rigs, these are not a 'one size fits all' option; a rig needs to be selected for the specific job

depending on the weight and space limitations of the offshore platform, the capability and specifications of the rig, and the activity it needs to perform. The economics of mobilising offshore drilling rigs needs to take into account the costs of mobilisation and demobilisation.

Some offshore platforms (e.g. Pohokura Platform B) cannot accommodate the space and weight requirements of a drilling rig, or even of smaller units such as a coiled tubing unit. In these cases, different solutions may be available such as barge or ship-mounted well intervention facilities, or jack-up drilling rigs which float or stand alongside the offshore platform to perform the work. These vessels must also be mobilised from overseas.

Pipeline infrastructure investment

In addition, ongoing investment is required to maintain the gas pipeline infrastructure in order to keep the pipes safe and operational, even if gas use reduces to a level where the transmission system can be run at lower pressure. For example, we understand that Firstgas currently spends approximately $40m per annum in capex on the gas transmission network, with a return on that investment allowed under the regulatory regime over the following sixty years for most asset classes.

As gas use reduces, fewer parties are expected to use (and therefore continue to pay for) the pipeline infrastructure. At some point, the cost of maintenance may well push the price of shipping gas above economically justifiable levels or capital may become less available for this type of asset given the risks involved, in turn affecting the availability of the infrastructure.

3.2 Gas is produced and contracted to meet long-term demand

As far back as the development of the first major offshore gas fields, Kapuni and Maui, gas field development in New Zealand has only taken place once demand has been established with contracts for predictable volumes and prices agreed, or with government support. For example, the Maui field was developed with the expectation of a need to support a number of new thermal electricity generating plants. Given Huntly was the only such plant developed by the government, excess Maui gas was available for an extended period.

Field operators need to contract demand for their gas before investing in development and production because of the large financial and lengthy time commitments involved, and because (as noted in section 3.1.1 above) decisions made during the development phase affect the level of production the field will be able to operate at over its producing life. To date, long-term gas supply agreements between producers and major gas users, who know their expected future gas demand, have provided the certainty of demand that producers need to invest in their developments.

In New Zealand, demand must be domestic as without pipelines to other countries or an export (LNG) industry, any extra gas developed cannot be sold on the international market except as processed product such as methanol.

Since 2013, emsTradepoint has provided a commercial trading platform on which balancing gas transactions and 'spot' gas can be traded. Trading activity has fallen in 2021 but during 2020, traded volumes accounted for between 4% and 5% of total market demand. 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.

At this level of trades, the gas spot market demand is too small and intermittent to underwrite ongoing field development. It is unlikely that this will change to any material extent, since 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).

Therefore, long-term baseload, large-volume (cornerstone) gas contracts are and will continue to be crucial for New Zealand producers to carry out ongoing development at reasonable cost.

3.3 Supply uncertainty

3.3.1 Reserves are not guaranteed

Reserve and resource assessments are no more than point-in-time estimates (albeit made by expert assessors) that are based on assumptions of existing technology and a given set of economic assumptions. There will always be a large number of risk factors involved with striking forward-looking estimates of this profile (some of which are discussed in section 3.3.3 below).

A field's gas 'reserves' (the 'P' figures) relate to those volumes of gas that producers have high confidence in recovering, but still have a range of uncertainty associated with them. The industry uses the Society of Petroleum Engineers' Petroleum Resource Management System to define this uncertainty as follows:

> *"The range of uncertainty is characterized by three specific scenarios reflecting low, best, and high case outcomes from the project. The terminology is different depending on which class is appropriate for the project, but the underlying principle is the same regardless of the level of maturity. In summary, if the project satisfies all the criteria for Reserves, the low, best, and high estimates are designated as Proved (1P), Proved plus Probable (2P), and Proved plus Probable plus Possible (3P), respectively."*

The 2P (proved plus probable) reserves discussed in section 3.1.3 above are also known as the 'P50' reserve, defined as the estimated volume of hydrocarbons that have a 50% likelihood of being equalled or exceeded (or conversely, of falling below that estimate). At the opposite ends of the spectrum, 1P reserves are estimated as having a 90% likelihood of being equalled or exceeded, and 3P as having a 10% likelihood. Averaged across an entire producing region, 2P reserves will most likely approximate the eventual total volume recovered.

As the portfolio of fields shrinks, confidence that these 2P reserves will be realised decreases, as a single field significantly varying from its 2P prediction has a larger impact on total recovered volume than if there was a bigger portfolio of fields to absorb this impact. This means that confidence in the accuracy of the 2P figure declines as the number of producing fields declines, with an increased likelihood in variation from the 2P number in either direction.

Contingent 'resources' (the 'C' figures) are those quantities estimated to be potentially recoverable but which are not currently considered to be commercially recoverable, with low/best/high estimates denoted as 1C/2C/3C respectively.

3.3.2 No built in redundancy in gas production

Unlike with many parts of the electricity system, the gas production sector does not normally operate to 'N-1' security (where the system is planned to remain operating satisfactorily if a facility falls out of service). This means that the response to an unexpected outage, reduced production from a field, or a sudden increase in demand for gas has to be dealt with through reduction in demand (planned demand response or unplanned demand diversion), rather than by back-up systems coming on-line.

Clearly the built-in redundancy that an 'N-1' standard provides comes at a cost. Because of the instantaneous nature of electricity and the cascading failure ('brown out' or 'black out') potential, consumers, regulators and commercial parties assume a willingness to pay this cost in the electricity sector. To date, a similar willingness of consumers to pay for N-1 is not evident in relation to gas supply in New Zealand.

3.3.3 Investment risk

Because of the way natural gas is found, developed and delivered to customers, there is inherent uncertainty throughout the development timeline and at every step of the development process.

Most capital for investment in field development competes with alternative capital allocation globally, in which estimated returns are discounted against technical, commercial and above ground risks. Changes in relative risk (for example, between fields or countries a producer may choose to invest in) affect capital allocation as much as changes in absolute risk. Therefore, the likelihood of investment to bring 2P reserves to market can decline even while the estimate of the 2P reserves themselves remains stable.

Technical uncertainty

Producers (and their financiers) take on the risk that subsurface conditions are not as expected, that findings from one or more wells are not replicated across a field, or that the production profile changes unexpectedly.

The risk tends to be highest at the front end (when less is known about the 'play') and during the decline phase (when operators increasingly target smaller and more marginal resources). With New Zealand fields progressing through their decline phase , technical and economic uncertainty is increasing.

'Above ground' risk

Investment decisions also take into account 'above ground' risk. Broadly, this refers to non-technical risks that may affect producers, including regulatory, political, security and environmental risks. For example, the prospects of government intervention and/or social conditions may limit or conversely encourage production and development of resources.

Commercial risk

As noted in section 3.2, field operators need to contract demand for their gas before investing in development and production because of the large financial and lengthy time commitments involved. In the absence of contracted demand, fields will not be developed as, unlike with overseas markets that are interconnected or that have sufficient diversity and volume of demand to support a larger spot market, uncontracted gas in New Zealand might not be able to be sold.

Managing investment risk

Currently investment risk is managed:

- by diversifying developments into different fields or countries, or through sharing risk with others. If one field does not produce up to P50 level, other fields may balance this out by producing more. However, as the gas market in New Zealand shrinks over time, single field production risks will have a greater impact on supply security
- through higher pricing and longer contractual terms reflecting the commercial risk – in New Zealand, the current long-term contracts with Methanex vastly reduce commercial risk, thereby facilitating development not only for Methanex, but for other gas users as well
- by stopping or reducing investment in fields or countries where the balance of risk and reward can no longer justify further investment when taking into account the technical/commercial/above ground risks.

3.4 Limited ability for flexible production

Since gas fields in New Zealand are developed to meet known (contracted) gas demand, field production cannot be materially increased in response to short-term (say, less than 18 months ahead), demand requirements. Equally, operating a facility substantially below its optimum capacity for anything beyond short periods of time brings additional risks.

3.4.1 Lower and upper production limits

Producers have some ability to adjust their level of production in a gas field, but only within certain limits.

As described under 'development' in section 3.1.1 above, the maximum capacity for any given gas processing facility is determined by decisions made early on about the type of facility developed, depending on known demand.

Facilities normally also have a minimum capacity, below which they cannot operate at all, determined by factors such as:

- risks of 'slugging' in well pipelines (unstable operation due to liquids build-up in the well stream at low rates)
- gas processing 'columns' or towers, which perform duties such as water removal, failing to operate at all below a lower limit
- lower limits of operation for other rotating equipment such as pumps and compressors.

Even above minimum capacity, operating a facility substantially below its optimum capacity for anything beyond short periods of time also brings additional risks. For example, operating at very low rates means that control valves may be in 'mostly closed' positions below their design optimum, which can lead to corrosion of parts and/or scale build-up.

As fields structurally reduce their production rates over time (particularly as they come off plateau towards end of life) it is quite common to replace parts of processing plants with smaller equipment (e.g. valves, internal components of pumps, etc) to avoid these issues. This then sets a new (lower) minimum rate, and usually also reduces the maximum rate.

At the other end of the spectrum, as noted in section 3.1.2, some (especially water drive) wells may be able to support short-term higher rates of production. However, this needs to be balanced against the risk of watering out the well, which would compromise the ability to produce any gas at all from the well in the longer term.

3.4.2 Production rates cannot pivot to take advantage of short-term prices

These lower and upper limits to the levels of gas that can be produced from a field bound the potential for producers to alter production rates in a field to provide short-term flexible supply.

This means that gas producers cannot significantly alter short-term production rates in response to higher short-term prices. Conversely, lower energy demand will not tend to reduce short-term contract prices, which are often fixed or linked to an alternative commodity price such as oil.

3.4.3 Storage can provide some flexibility

One solution to this limitation on flexibility is gas storage, such as the Ahuroa underground gas storage facility located in Taranaki. If properly planned and contracted, gas storage can provide flexibility in the rate of gas able to be delivered or in volumes required to cover peak demand both in the short term (daily to weekly) and the medium term (weekly to monthly). We discuss gas storage further in section 4.4.1.

4 Outlook

A range of views of the outlook for natural gas in New Zealand have been modelled in recent years, which could represent equally possible futures. As part of this investigation, we commissioned supporting analysis on the gas supply and demand outlook over the period to 2035 from Concept Consulting,[4] which we have used as our base and set out in section 4.1 below. Some other forecasts are summarised in section 4.3, with key factors impacting the supply outlook in section 4.2 and other developments that may affect it in section 4.4.

Section 4 summary

While there are differences between various organisations' modelled outlooks, all see significantly reduced demand for natural gas in New Zealand as the transition progresses and some natural gas remaining in our mix in 2050. Estimates are between 50 PJ and 110 PJ remaining in 2035 and between 26 PJ and 50 PJ in 2050. We have assumed that natural gas will not be used as fuel for electricity generation beyond 2030 (which is a different approach than most modelled scenarios), but that it will be needed for some petrochemical, industrial, commercial, agricultural and residential use beyond that.

Supply of natural gas will likely be tight for next winter and possibly into 2023, but investment is occurring. With industry coordination, continued investment and good risk management across the energy sector, gas supply should be able to be managed to meet demand in the short to medium term.

There is more confidence that tight conditions will ease by 2024, given recent and planned investment, expected new renewable electricity generation projects and potential closure of the Tiwai aluminium smelter.

In the longer term, our expectation is that Methanex will remain in New Zealand and continue to support production investment, and therefore natural gas will be available to support electricity generation and major users.

Electricity generation will also require:

- thermal electricity generating plant to remain available for use
- sufficient flexibility of gas supply to enable remaining thermal plant to operate in an increasingly variable manner.

[4] See https://www.gasindustry.co.nz/work-programmes/gas-supply-and-demand/gas-demand-and-supply-projections-2021-to-2035/

4.1 Commissioned supply and demand outlook

Concept developed three supply scenarios for this analysis based on the gas production profiles, consolidated and released by MBIE in July 2020, which were in turn based on field operators' January 2020 estimates of how 2P reserves would be produced over time. In Concept's modelled gas supply scenarios, the gas production profile estimates were adjusted with the following assumptions for the base, lower and higher cases:

- The base case assumed annual production capability at Pohokura would be the same in 2022 as 2021, and thereafter it would be 25% lower than the 2020 gas production profiles. The profile for Kapuni production was slightly altered to reflect an expected one-year delay in the planned drilling programme. Supply capability for other fields followed the production profiles disclosed in mid-2020.
- In the lower case it was assumed that Pohokura production would not recover to former levels, which saw it reducing by around 50% compared to the 2020 projections.
- The higher case assumed work at Pohokura in summer 2021/2022 (which is now expected to take place in 2022) would result in a complete restoration of supply capability and the production profile forecast from early 2020 could be achieved.

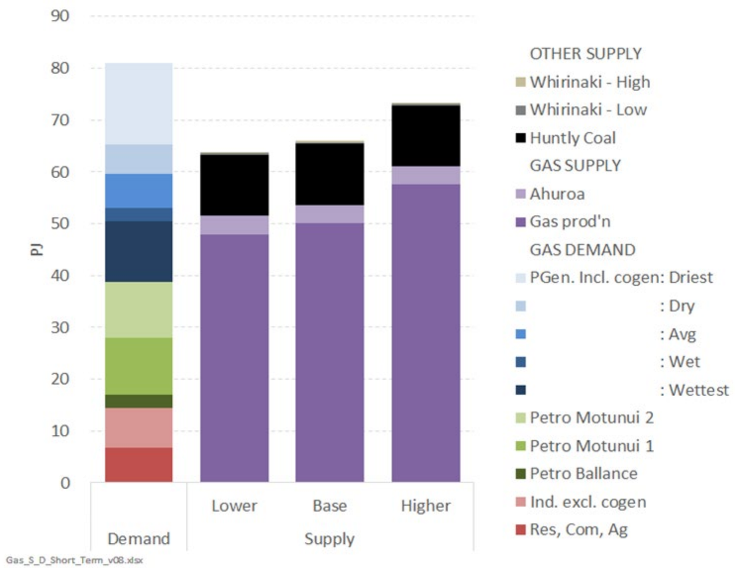
Since Concept's report was released, updated production profiles have been released and a number of parties have made announcements of works that are underway or expected to commence in the next few years – some of which improve and some of which worsen the outlook. With the updates, we see the short-term forecast for 2022 remaining tight (as shown in Figure 1), with the higher case over the transition period now clearly unrealistic. The longer-term outlook to 2035 shown in figures 2 and 3 below reflect the updated profiles.

4.1.1 Near-term outlook

It appears that the tight situation experienced in the electricity market through the middle of 2021 has been largely alleviated due to some welcome hydro inflows and sustained high levels of thermal generation through the critical period. A large contributor to this has been Methanex, which agreed to reduce its demand at its Motunui plant in order to provide Genesis with the equivalent of ~500 GWh of electricity during a period of high electricity demand (albeit that some of this may have been onsold to other gas users), having earlier mothballed its Waitara Valley plant due to lack of gas supply.

However, gas supply remains tight for many users coming up to re-contracting for their gas supply as their existing contracts expire and these tight supply conditions appear likely to continue into 2022 and possibly into 2023 or beyond. The near-term outlook depends on the success of the infill programme currently underway at Maui (and beyond that, the Maui-B programme) and work that is currently occurring at other fields, such as remedial work at Pohokura planned to take place in 2022. As was the case this year, the outlook is also heavily dependent on the level of hydro inflows, with greater inflows lessening the need for gas to support thermal electricity generation.

Figure 1: Winter 2022 – projected gas demand and supply



Source: Concept analysis

As shown in Figure 1 above, Concept's analysis indicated a shortfall of gas supply (purple stacks in the graph) for winter 2022 (June through September) for even an average hydrological year in all the scenarios modelled except the higher supply case (assuming complete restoration of supply from Pohokura, and with Ahuroa full and available to provide seasonal flex). In an average hydrological year, it is expected that Huntly coal-fired generation will be required to meet demand – and will need to run at full capacity along with Whirinaki and Huntly diesel-fired generation to cover a 'standard' dry year. If a very dry year eventuates, or if gas supply is at the lower scenario, thermal supply will not meet expected demand.

In those situations, demand response will be required to cover the balance, which could entail:

- some gas users reducing demand and on-selling some of their entitlement to generators to support gas-fired electricity generation

> In winter 2021, Methanex agreed to temporarily idle one of its Motunui facilities for three months to provide between 3.4 PJ to 4.4 PJ for Genesis to purchase.[5] This provided the equivalent of an additional ~500 GWh of electricity into the system (for scale and context, natural gas fuelled a total of 1,365 GWh and wind fuelled 652 GWh of electricity in June 2021), and was on top of Methanex having already mothballed its Waitara Valley plant earlier in the year in response to the tight gas supply situation.
>
> There is also a two-year winter/summer gas swap agreement between the two parties for 2022 and 2023, where Genesis will supply gas to Methanex in the summer in exchange for Methanex supplying gas to Genesis in the winter.

- some electricity consumers reducing demand

> New Zealand Aluminium Smelters (NZAS) agreed to reduce its electricity consumption at Tiwai Point in early 2021 by up to 30.5 MW for two months, to provide relief to Meridian. This reduced late autumn demand by nearly 50 GWh when it was needed, partially replacing later winter reduction that Meridian could have called on under its electricity supply agreement with NZAS.

The tight energy (hydro and gas) supply position in the short term is likely to contribute to very high wholesale gas and electricity prices – reflecting the price signal needed to induce demand reduction (planned demand response such as industrial gas users mothballing plant or agreeing in advance to reduce their production, or unplanned demand diversion) and new electricity and gas production development.

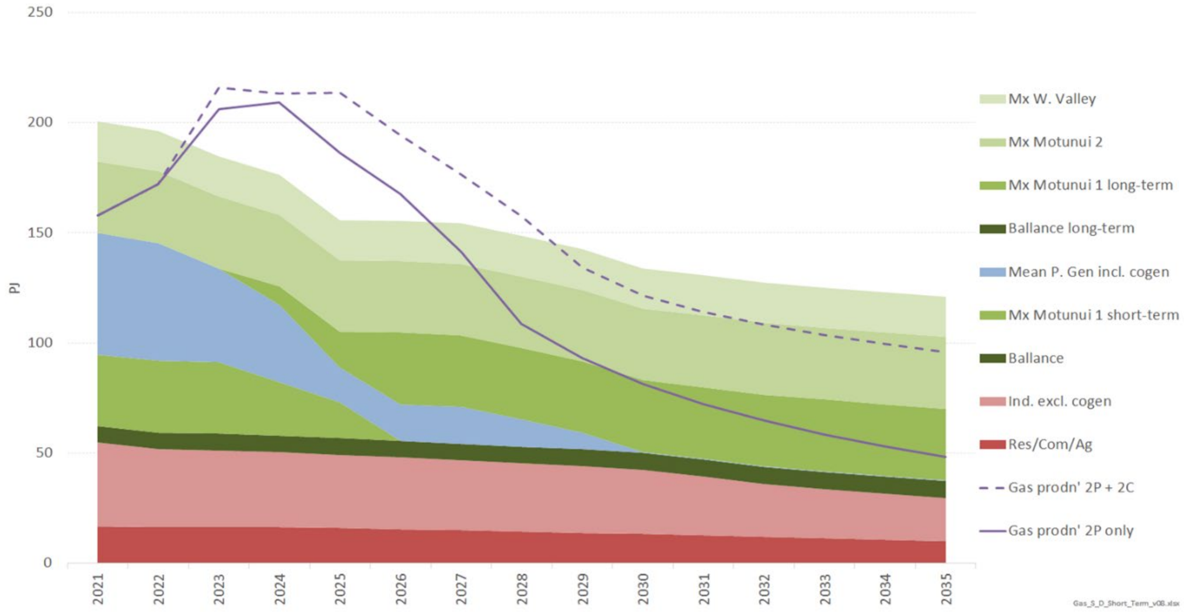
4.1.2 Outlook beyond the near-term

There is more confidence that tight conditions will ease by 2024. This is especially in light of recent successful investments in production and an expectation that planned work programmes at all other major gas fields will see more gas being brought to market. In addition, committed new renewable electricity generation projects are expected to be on stream, reducing thermal generation demand for gas. Together these are likely to lift supply available to other gas users by around 30-45 PJ per year by 2024. These factors can be seen in Figures 2 and 3 below, which show aggregate supply based on the 2021 gas production profiles. In addition, if the Tiwai smelter closes at the end of 2024, that will further reduce demand for gas to generate electricity.

The solid purple line in Figures 2 and 3 shows forecast gas supply based on current field deliverability and the remaining proven + probable (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. The blue band in Figure 2 shows anticipated electricity generation demand in a 'normal' hydrological year, and in Figure 3 a 'dry' year (projected 1 in 10 years). The aggregate will be higher in a 'very dry' year (based on around 1-in-50-year projections). Electricity generation demand for gas is zero from 2030, when the Government's target is for 100% renewable electricity generation.

[5] See https://www.genesisenergy.co.nz/about/media/news/genesis-and-methanex-work-together-to-improve-ener

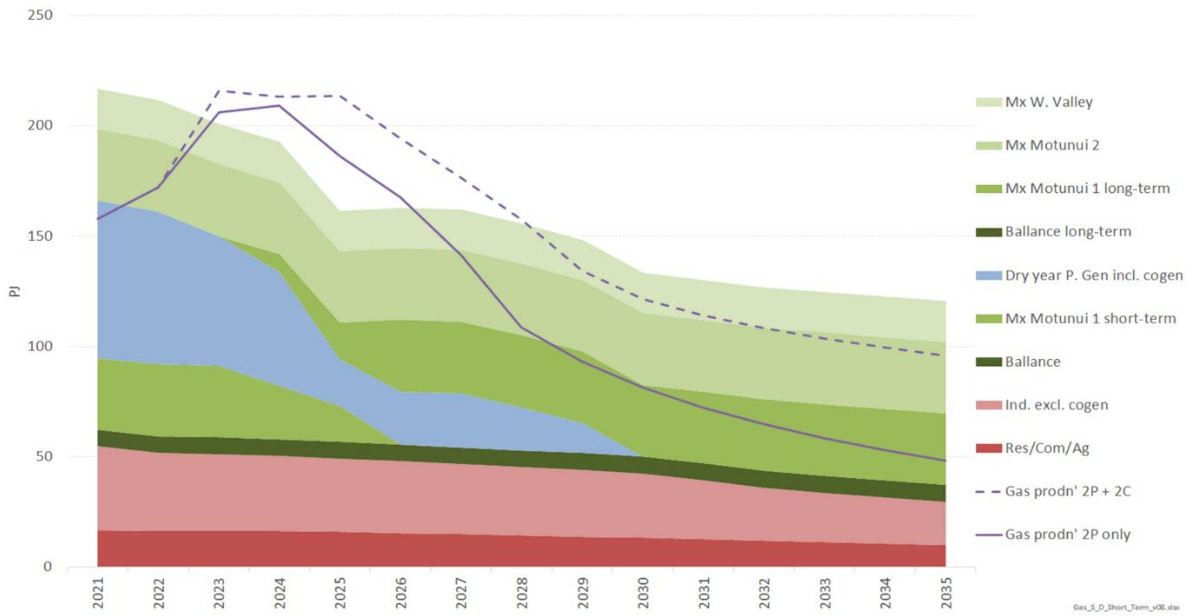
Figure 2: Base case supply with mean hydrology



Source: Concept analysis

Given the reported numbers for 2C resources, we understand that there are sufficient gas reserves 'in the ground' to meet demand until at least 2035 (and likely significantly beyond), provided that 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 successfully developed to meet demand. This includes gas supply to support security of electricity supply, provided the thermal generating plant is there to use the gas. We have heard some concern that, even if gas is available as a fuel, thermal generating plant closures and a uncertain timeframe for returns on investment in gas-fired peaking generation may result in not enough plant being available to provide cover for sustained dry periods post 2023.

Figure 3: Base case supply with dry hydrology



Source: Concept analysis

Case Study: Methanex

As the largest gas user in New Zealand by some margin, Methanex has an important role in supporting the stable operation of the gas sector. It provides a base level of demand to maintain sufficient levels of gas deliverability throughout the transmission network and from the gas fields. This was recognised during New Zealand's first COVID-19 lockdown in April 2020, during which Methanex was deemed an essential service. Its continued operation meant that sufficient gas demand remained in the system so that gas fields could maintain production above their lower limits to ensure no permanent damage to the producing sites.

Methanex also performs two other important roles in the gas sector.

- It provides stable long-term certainty of a large volume of contracted demand to support upstream investment in the development of supply.
- It is the only gas user that can make significant enough adjustments to its level of gas demand to counterbalance the potential swing in gas supply needed to support electricity demand due to unpredictable hydrology.

Methanex has also performed a balancing role for the electricity sector in the past by reducing demand and on-selling some of its entitlement to gas-fired electricity generators. In its submission to our Consultation paper, Methanex noted:

"Methanex has played a "flexible" role in the New Zealand gas industry over a long period of time. While we have always desired to operate a full rates, we have made commercial decisions that have meant decreases or increases in production capacity based on our ability to enter long-term contracts and earn a return on capital. We have most recently demonstrated this through the idling of Waitara Valley, and the unfortunate loss of permanent jobs in Taranaki, and the temporary shutdown of one Motunui facility to support the energy sector when renewable sources did not deliver as expected."

The particularly dry conditions at the start of winter 2021 meant that there was elevated thermal generation demand. By temporarily idling one of its Motunui trains to reduce its own gas demand, Methanex was able to free up between 3.4 PJ and 4.4 PJ of gas over three months for Genesis, enabling a commercial arrangement between the parties to provide sufficient gas supply to support ~500 GWh of electricity generation.

Methanex and Genesis have also agreed to a longer-term winter/summer gas swap agreement for 2022 and 2023, where Genesis will supply gas to Methanex in the summer in exchange for Methanex supplying gas to Genesis in the winter.

There is no alternative to Methanex that could provide this level of demand response flexibility as no other major users even come close to its scale of gas demand, nor has any other user shown the same level of flexibility in their operations.

Analysis shown in Figures 2 and 3 above indicates that there is sufficient gas supply to support operation of 1-3 methanol units until at least 2030, even in a year with sustained dry periods, depending on the rate at which other gas demand recedes and how quickly contingent resources are developed. If Methanex's own gas supply (or supply at a reasonable long-term net price that supports its continued operation here in New Zealand) were compromised and its gas demand declined substantially as a result, that would reduce or even remove a key funder of development and source of flexibility for the gas system. The ramifications of this would be felt throughout the gas and electricity sectors.

4.2 Key factors that will impact the gas supply outlook

Figures 2 and 3 above highlight two important variables that will have a large impact on New Zealand's future gas outlook: gas production (how much of the dotted purple line will be developed) and electricity demand (the size of the blue band). These two factors correspond to two key areas of uncertainty: investment and hydrology.

4.2.1 Investment

As noted above, 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. If investment does not happen at the levels needed to fill medium and longer-term gas demand, this is likely to lead to reduced levels of gas supply. This will mean that businesses, particularly those that are not sufficiently contracted, may not be able to secure all of the gas they would like to at prices that support their ongoing business continuity.

Gas demand and supply in the period from 2025 to 2030 will be strongly influenced by decisions that are being made now. Whether gas is available for all users depends on producers' willingness to invest in supply-side assets. This will be influenced by customers' willingness to enter into contracts needed to underpin investment.

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 at least stable) demand providing a degree of certainty about the long-term economics of the project. 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.

While contracting processes to support investment have occurred smoothly in the past, there are added challenges in the current environment. In particular, some policies (e.g. the Government's Emissions Reduction Plan planned to be finalised in May 2022) 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.

4.2.2 Hydrology

Along with peaking generation and seasonal flexibility, gas-fired generation performs a critical role providing cover to the electricity market when hydro inflows are lower than expected (in a 'dry year'). Electricity generators can ramp up gas-fired generation when there is a period of low hydrology and hydro generators are conserving water.

Hydrology is unpredictable - it is unknown from year to year what volumes of inflows the hydro catchments will receive, and in turn, it is unknown from year to year what levels of gas supply will be required to fuel gas-fired generation to fill in for limited hydro generation. Demand from electricity generation currently accounts for ~30% of total gas demand in a mean hydrological year, and in a 'dry year' with sustained dry periods, this can increase by nearly 30 PJ (or even more in a very dry year). The difference in size of the blue band in Figures 2 and 3 demonstrates the difference between demand in an average and a dry year across the time period to 2035, and the range of blues in the demand stack in Figure 1 on page 22 above is an example (for 2022) of what the difference could be in a range of hydrological scenarios over the winter months from wettest to driest.

The overall volume of natural gas needed to fuel electricity generation is expected to decline as more renewable generation is built and thermal plant is decommissioned. However, the electricity sector is expected to rely on the ready availability of flexible thermal fuel – potentially at higher immediately deliverable levels given greater 'swing' from weather-dependent renewables - until at least 2030. A reducing number of operating thermal generating plants add to the challenge.

Unknown hydrology has the potential to dramatically shift the demand side of the equation – even as late as 2029, when the variation between a mean hydrological year and a dry year could potentially see demand for an additional ~10 PJ of gas for electricity generation. Without proper preparation, this could lead to unbalanced supply and demand, potentially resulting in constrained gas supply for electricity generators who are not sufficiently contracted precisely at the time when they most need to be able to generate electricity.

4.3 Other natural gas outlook forecasts

As noted, the outlook developed by Concept Consulting for this investigation discussed in section 4.1 above is only one of a range of views of the future of gas in New Zealand. Others may hold different expectations about likely investment, policy and global markets, for example. Many other forecasts of the energy sector have been modelled in recent years, which could represent equally possible futures.

We have summarised key points from other recent New Zealand models in this section – from the Climate Change Commission, the Business Energy Council/EECA, the Electricity Demand and Generation Scenarios compiled by MBIE, and Transpower.

While there are differences, there are also some consistent themes. Most notably, all see significantly reduced demand for natural gas in New Zealand as the transition progresses, and some natural gas remaining in our energy mix in 2050.

4.3.1 Climate Change Commission

The Climate Change Commission (CCC) released its final advice to government in May 2021.[6] Its demonstration path showed around 1.7 TWh of gas-fired electricity generation remaining in 2035 (requiring around 22.8 PJ of gas). The CCC saw a phase down of gas consumption from all users in response to rising emissions prices and improvements in energy efficiency. Some electricity generation transitions in the modelling from gas to renewables. By 2035 there is a 50% reduction in gas consumption from process heat over 2019 levels. Mass market gas consumption reduces gradually, reflected in the modelling as no new gas heating systems installed from 2025 and starting the phase out of existing gas use from 2030.

The CCC recognised the role of hard-to-abate industries, and its model maintained operation of major gas consumers such as NZ Steel and Methanex through to the 2035 budget and beyond. The CCC assumed the continued operation of Methanex, with the closure of the Waitara Valley train at the end of 2020 and the Motunui trains at the end of 2029 and 2039 respectively. The CCC ran alternative pathways and sensitivities to test different outcomes. The CCC's demonstration path sees approximately 83 PJ of natural gas use remaining in 2035 and 26 PJ in 2050.

Figure 4: Climate Change Commission Projected Gas Demand

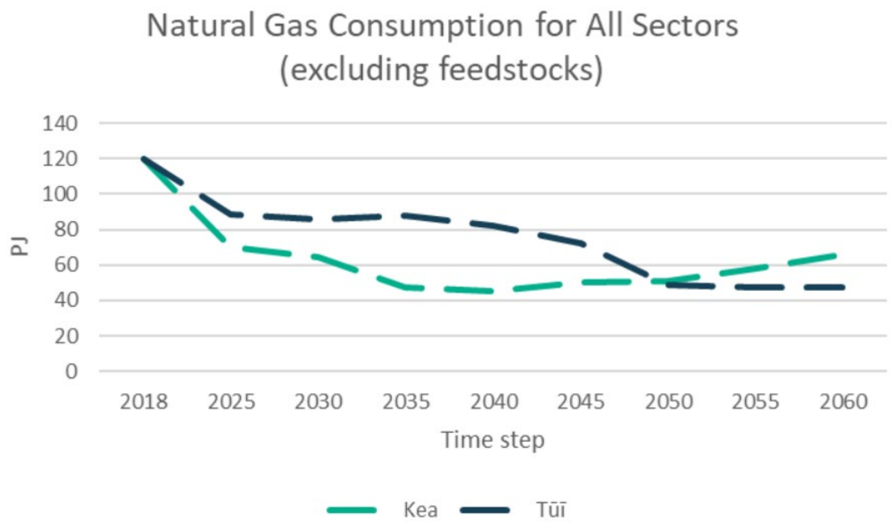
Source: Ināia Tonu Nei, a low emissions future for Aotearoa, p154

[6] He Pou a Rangi Climate Change Commission, Ināia Tonu Nei, a low emissions future for Aotearoa, May 2021, https://ccc-production-media.s3.ap-southeast-2.amazonaws.com/public/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa/Inaia-tonu-nei-a-low-emissions-future-for-Aotearoa.pdf

4.3.2 Business Energy Council/EECA TIMES-NZ 2.0 model

In May 2021, the BusinessNZ Energy Council, alongside EECA, released an interactive tool based on an update to the International Energy Agency's TIMES model[7] and building on its earlier 'BEC2060' work exploring possible energy futures in New Zealand. The TIMES-NZ 2.0 model provides insights into two potential scenarios for New Zealand's energy future to 2060. As shown in Figure 5, demand for fossil fuels decreases significantly in both scenarios, but there remains an ongoing role for natural gas. Gas use continues in the industrial and commercial sectors but drops out of the residential sector by 2040 in both scenarios, due to a combination of rising carbon prices and increasingly attractive alternative technologies, making switching away from gas economically optimal. Gas support for peaking electricity generation is retained. The model sees between 50 and 90 PJ of natural gas demand in New Zealand in 2035 and both scenarios with approximately 50 PJ of gas consumption remaining in 2050.

Figure 5: BEC/EECA Projected Consumption of natural gas in TIMES-NZ 2.0 scenarios



4.3.3 Transpower's Te Mauri Hiko

In March 2020, Transpower released an update to its "Te Mauri Hiko" report, *Whakamana i Te Mauri Hiko*, on the future of the electricity sector in New Zealand. Under its base case, 95% of New Zealand's electricity would be generated by renewable sources by 2035 and 100% by 2050 in a normal hydrological year.

Electricity demand is modelled to increase from the current level of 42 TWh in 2020 to 70 TWh by 2050, with an estimated 7 TWh of that increase created by the electrification of industry.

This leaves gas supplying 12% of industrial energy demand in 2050, down from 31% in 2020. In Transpower's outlook, natural gas also continues to play a role for mass market users in 2050, providing 7% of household energy use (down from 18% in 2020) and 13% of commercial energy use (down from 22% in 2050). Transpower's estimated demand is shown in Figure 6, which is Figure 4 at page 25 of Whakamana i Te Mauri Hiko.

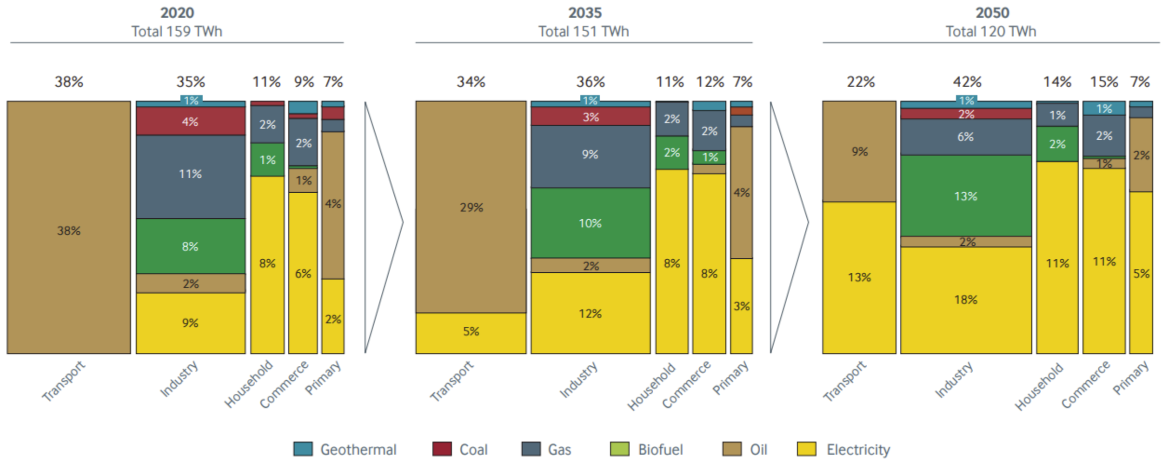
The modelling underpinning Whakamana i Te Mauri Hiko estimates that by 2035, approximately 400 MW of existing gas-fired electricity generation will have been phased out of the market and replaced by four flexible 100 MW gas-fired peaking power stations. Thermal plants operating in the market will be firming an almost entirely renewable and increasingly intermittent generation base and are likely to be on standby and not generating for long periods of time.

Transpower highlights the challenges in supporting investments into the future considering the declining utilisation rate of gas-fired generation combined with the rising prices of gas and carbon, the nature of take-or-pay gas supply contracts and ongoing costs associated with connection to the gas supply pipeline. In 2035, Transpower

[7] The TIMES model is an energy technology systems analysis programme/model that has been used by over 60 countries worldwide and has been updated for New Zealand scenarios as the TIMES-NZ 2.0 model, available at https://times.bec.org.nz/ and at https://www.eeca.govt.nz/insights/new-zealand-energy-scenarios-times-nz/.

estimates that gas peaking plants in the New Zealand market will have a utilisation rate only one third of gas-fired plants today. It says gas-fired generation will run much less often, but will be critical to keeping the lights on.

Figure 6: Transpower's estimated delivered energy demand by type and sector

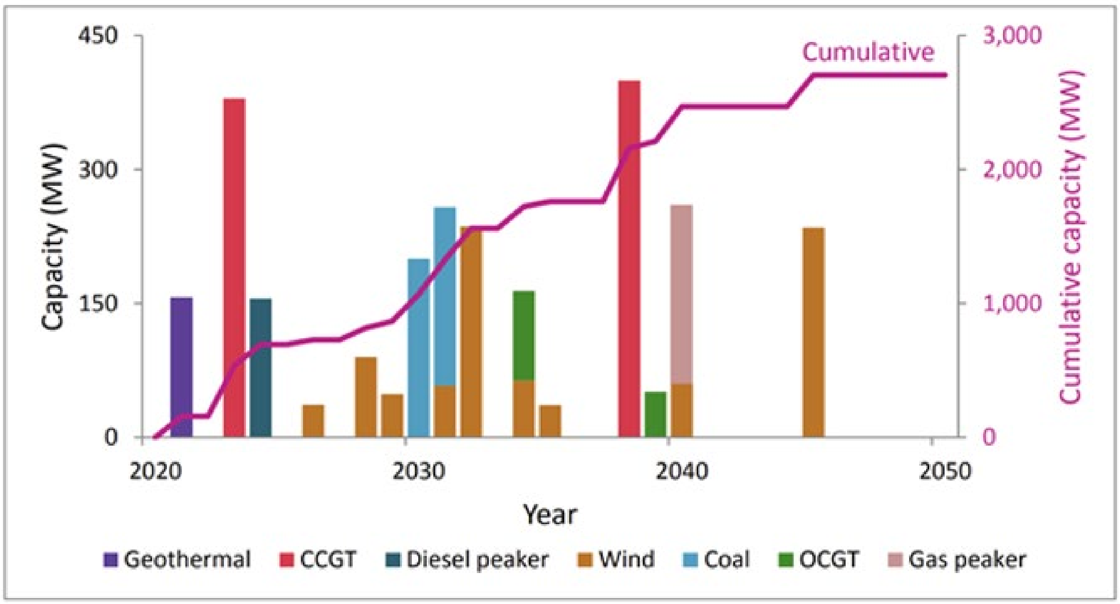


4.3.4 Electricity Demand and Generation Scenarios

MBIE regularly produces the Electricity Demand and Generation Scenarios (EDGS), with the latest update published in July 2019[8]. Their key purpose is to enable the Commerce Commission to assess Transpower's planning proposals for future capital expenditure on the electricity transmission grid.

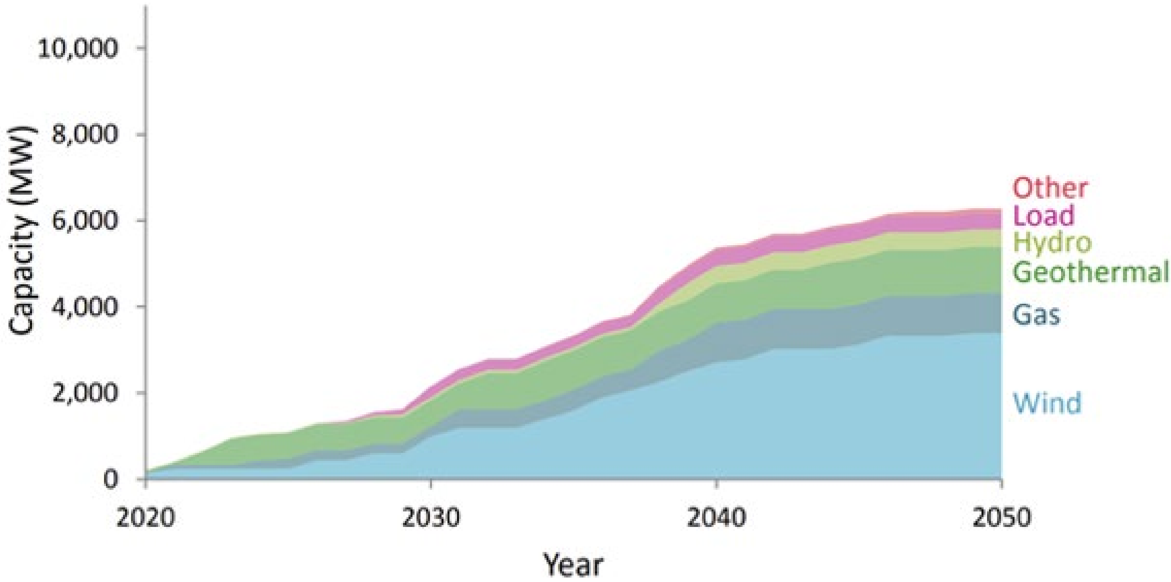
The majority of new build generation in the model is renewable, reflective of assumptions around a decrease in the cost of solar and wind technology and in the volume of gas available for supply. The EDGS model forecasts a rise in the share of electricity generation from renewable sources to around 95% in all scenarios. Older gas-fired generators are gradually decommissioned over the next 20 years as existing thermal generation is displaced by renewables (see Figure 7[9] below), and an additional 930 MW of gas-fired peakers are commissioned by 2040 to provide responsive capacity to support this higher proportion of renewables (see Figure 8[10] below).

Figure 7: EDGS 2019 Projected schedule of generation decommissioning



[8] See https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios
[9] Figure 14 at page 26 of the EDGS
[10] Figure 15 at page 27 of the EDGS

Figure 8: EDGS 2019 Projected cumulative new generation build



4.4 Other developments that may affect the outlook

Many people we heard from during the investigation noted developments underway that they expected to continue without intervention being required. These include additional gas storage, and an increased role for biogas and development of hydrogen as a fuel source for New Zealand. Some parties were also considering the potential for development or importation of liquefied natural gas (LNG), which has been discounted previously due to economic considerations but becomes a more realistic option at the higher gas prices we have seen recently.

These developments have the potential to change the outlook described above, albeit in some cases later in the transition period or beyond.

4.4.1 Gas storage

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

- 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 gas producers and/or users to manage risk by having some reserve:
  - to firm or provide seasonal support for electricity generation
  - to absorb excess production or in case of gas production (or supply) failure.

Storage is not a viable option for petrochemicals with their much larger-volume needs and associated lower willingness to pay for it.

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 (in each direction) and a total 18 PJ of capacity. However, the incentives to utilise the available storage, including to fill ahead of subsequent demand, appear to be limited; 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.

Potential investment in new storage

Gas storage can be developed if an acceptable commercial arrangement can be agreed between interested commercial entities, as occurred with the Ahuroa gas storage facility – and provided there is expected to be gas available to fill it.

A key factor for commercial parties considering developing additional storage relates to the time duration, over which it would be used as New Zealand continues its transition to renewable electricity. Assuming that gas is only needed to support electricity security of supply until 2030 or not long thereafter, this significantly reduces:

- the timeframe for recovery of a return on investment (if the primary investment driver is providing backup fuel supply for electricity generation) and accordingly the required rate of return
- the volume of storage that will have a long enough operating life to provide the required return (if the focus is on gas for non-electricity use, which has a much lower requirement for flexibility but will persist beyond 2030).

If an investor could get comfort that the timeframes involved still make investment in storage viable, the other consideration is the working capital of the gas storage user, which would be tied up for an unknown length of time as gas (already paid for) is 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 or more, which depending on gas prices could represent significant expense (thereby decreasing the likelihood of gas being able to be stored and subsequently sold economically.

Some participants have indicated that they consider additional storage will become commercially viable. For example, Genesis indicated in its submission to our consultation paper that it believes *"that the industry can arrive at a gas storage solution that is commercially viable and supports the decarbonisation of New Zealand's electricity sector and the economy more broadly."*

Is further storage needed?

As thermal electricity generating plant is increasingly replaced by new renewable generation, there is expected to be a decrease in overall demand for gas to support electricity generation. However, more renewable electricity generation means more intermittency in the electricity system, which is likely to increase demand for load firming and flexibility over the next decade.

Compounding this are the uncertainties of hydrology, whether the Tiwai Point aluminium smelter (or another equivalent load) will remain operating beyond 2024 and the pace of transition path towards the 100% renewable generation policy target. Overall, analysis suggests that the total potential demand for fuel (gas and coal) to support thermal generation could vary by as much as 70 PJ in any given year across the whole year depending on hydrology (note that Figure 1 only considers June to September 2022 and not a full year). There is currently insufficient gas supply to deal with this level of variation and, even if there was, there is insufficient storage capacity and flexibility to deliver this range.

This makes storage and other flexibility mechanisms more important, and means that the greatest demand for stored gas is likely to come from electricity generation. Based on public statements from thermal generators on the extent of extra gas storage that is needed and the volume of coal that has been imported in 2021, it appears the thermal generation sector expects to require an additional 25 PJ of flexible gas volume in any given year. Genesis alone has said that its modelling supported a requirement for access to around 20 PJ of this, with capacity to inject/withdraw 55 TJ per day (so that the total gap between maximum and minimum demand, or 'cycling capacity' is around 110 TJ per day). In total, Enerlytica suggests that the electricity generation sector could require operational flexibility of a bit more than double that, at up to 250 TJ per day if the Taranaki Combined Cycle generating plant (TCC) remains in the market (or 175 TJ per day without TCC).

The downstream and expected future major industrial loads tend to be complementary in the level of flexibility they require, in that different sectors have peak demand at different times. This means that there is a balancing or smoothing effect between loads, at least to some degree, reducing the overall system flexibility needed to provide security of supply to them to around 50-60 TJ per day in each direction (injection and offtake), or a cycling capacity of around 100-120 TJ per day. To meet this downstream and industrial demand through the year, around 4-5 PJ of total storage volume is expected to be needed.

It is important to note that even this level of additional storage for both electricity generation and industrial/downstream customers would not on its own provide full risk insulation against upstream deliverability issues, e.g. if a field suffers an outage. A suite of existing mechanisms and other solutions will be needed to provide the balance of flexibility and security required.

4.4.2 Liquefied natural gas (LNG)

Given that it is likely there will be sufficient domestic natural gas production to meet demand until 2030 (see discussion in section 4.1 above), we consider it unlikely that investment will be made into developing the infrastructure to import LNG into New Zealand in the short to medium term. However, some parties consider that LNG provides significant potential security of supply and flexibility benefits, the infrastructure can now be invested in at smaller scales than was previously feasible and could be developed if a commercial case were established over the longer term.

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 destination, LNG is heated to restore it to its gaseous state then injected into the local gas transmission and/or distribution networks or combusted at the point.

New Zealand has not previously developed or imported LNG, generally because there has been no requirement until now for the flexibility it offers, the required scales of investment were significant relative to the demand, and therefore the economics have not supported it to date. However, LNG technology and markets have seen major developments in the last decade and prices have become comparable to what some users have been paying for natural gas in New Zealand recently.

These include developments include FSRUs (floating storage and regasification units), which require much less onshore construction activity as the infrastructure for importing, storing, and converting LNG back to gaseous form is onboard the FSRU, which is similar in design to a LNG carrier ship. FSRUs are fully mobile and able to be chartered, meaning that the infrastructure necessary to import LNG could potentially be mobilised and released each at short notice to meet market conditions at a relatively low upfront capital cost. This is an important aspect for a project for New Zealand as it minimises the risk of an investment in import facilities becoming stranded and would enable an import option to be compatible with the 2030 target for achieving 100% renewable electricity generation.

A study by Enerlytica has identified three possible locations for LNG import in New Zealand, each with its own benefits and limitations.

1. Marsden Point: A floating storage unit (FSU) and floating regasification unit (FRU) moored permanently to the existing jetty could receive LNG transferred from a shuttle carrier via conventional ship-to-ship transfer with the carrier and FSU alongside each other. LNG operations appear likely to be able to be carried out under existing resource consents, which could significantly reduce construction time to 12-24 months. A major drawback with this option however is very low (20 TJ/day) existing transmission capacity in the Northern pipeline system, although this could be increased to 30 TJ/day with additional compression.

2. Maui-A: LNG would be transferred at sea, via ship-to-ship transfer, from a shuttle carrier to the FSRU connected to a single-point mooring system. The FSRU would connect, via the mooring system, to the Maui-A wellhead platform and the existing 35km undersea pipeline, through which re-gasified LNG could be exported into the existing high-pressure gas network. This option has the advantage of using existing infrastructure that is underutilised, but would require 24-36 months of construction time and significant additional costs in order to build a system that is resilient to the rough Tasman Sea conditions.

3. Port Taranaki: LNG could be handled through Port Taranaki in a region which is already well serviced by existing high-capacity gas infrastructure. However, the Port's existing jetties are unsuitable to accommodate an FSRU and shuttle carrier alongside each other for cargo unloading without disrupting other port operations or other port operations constituting a hazard to the FSRU. Construction time to strengthen the existing breakwater and add new mooring facilities alongside it is estimated to be 12-24 months for this option.

In some countries, LNG imports complement natural gas supply to provide the required gas availability and flexibility. In particular, when compared to other alternatives such as storage and demand response, LNG may better fill the niche to provide greater flexibility to gas supply in New Zealand. During this investigation we heard mixed views on the need for and potential of LNG imports into New Zealand. Some submitters considered that indigenous production should be prioritised, while many others believed that further investigation into LNG was warranted.

As noted in section 4.1 above (Outlook), we anticipate sufficient domestic natural gas production in the medium term to meet New Zealand's demand, due to current and planned development activities. For this reason, we consider investment in LNG is unlikely to proceed in the short to medium term, but it could be developed as an alternative provider of flexible supply if a commercial case were established over the longer term.

4.4.3 Biogas

Submitters to our Consultation paper saw an important role for biogas, with calls to maintain optionality and for an accelerated approach. This is consistent with statements from various industry participants and a recent report[11] recommending consideration of options to accelerate development of the biogas and hydrogen industries and to improve the optionality for future gas pipeline repurposing. Some see this as a government-led role. Our view is that joint consideration by government, infrastructure businesses and other key stakeholders would be more likely to come up with workable options.

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.

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.

Biogas at Tirau

At Fonterra's Tirau site, methane (biogas) generated from the site's anaerobic wastewater treatment pond (one of the largest wastewater treatment plants in the Southern Hemisphere) has been used to partially fuel the site's gas boilers since 1983 – providing around 75% of the thermal energy required to run its boilers or 5% of the site's total energy needs (12,400GJ last season). The sludge from the pond has a high lime and phosphorus content and is removed annually to fertilise mainly maize cropping land nearby. Fonterra has also installed an anaerobic digestor at its Darfield site with the aim of using the biogas produced in the future to displace steam currently generated from coal.

EECA, Beca, Fonterra and Firstgas have recently released a report on biogas and biomethane in New Zealand, showing sufficient feedstock to provide a potential 15.6 to 19.9 PJ of biogas per year. This additional biogas would come mostly from livestock manure, but also industrial waste, crop residue, municipal and commercial food waste, municipal wastewater treatment sludge, and industrial effluents containing dissolved organic material. The report notes that feedstock co-digestion could further increase the potential.

This would more than cover 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).

While biogas tends to be used at its production site, it can also be refined and injected into the reticulated natural gas network using current infrastructure.

- In Denmark, biogas is increasingly being upgraded to biomethane and injected into the gas network and the country is on track to reach its targtet of 100% biomethane in its natural gas network by 2050.
- In France, 123 out of 860 biomethane plants inject biomethane into gas distribution networks.
- In New Zealand, while biogas is not injected into the broader network to any significant degree, Nova gas injects biomethane produced at its landfill production plant into its local network.

Work is also being undertaken to investigate how New Zealand's 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

[11] NZ Gas Infrastructure Future Working Group, *Findings Report*, 13 August 2021, pages 27-28, R2 and R7

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.

4.4.4 Hydrogen

Hydrogen has been gaining traction internationally and in New Zealand as a viable alternative to natural gas, since it can deliver the same qualities of natural gas without emitting CO_2. The main focus for hydrogen internationally is on uses that are not well suited to electrification, such as industrials like steel, cement and chemical manufacturers, and transport applications like heavy vehicles, marine and aviation.

Introducing a large-scale hydrogen economy to New Zealand will require far reaching and capital-intensive investment and development, and major change throughout the energy sector.

Hydrogen production facilities must be developed with access to sufficient electricity supply to drive the electrolysis for hydrogen production. End-use technologies must be adapted or swapped in order to be able to use hydrogen. Suitable standards need to be developed. Transmission and distribution networks need to be updated to account for the change in fuel consumption and deal with practical issues like embrittlement and potential cracking of steel pipes (around a third of the Firstgas transmission network) when exposed to high pressure hydrogen. With these changes, a hydrogen economy could be established in New Zealand for domestic consumption as well as international trade.

A number of recent announcements and studies are evidence of the beginnings of an emerging hydrogen industry in New Zealand.

- In March 2021, Firstgas announced its plans to gradually supplement natural gas transported through the transmission pipeline with hydrogen in increasing proportions, starting with a 5% blend and reaching 100% hydrogen in the pipes by 2050. The target would rely on continued investment in the gas networks during the trial phases (which are starting immediately), with the first 1% of hydrogen blend expected in the transmission pipes in around 2030 increasing to a 20% blend by around 2035.
- Meridian and Contact have recently published a study they jointly commissioned from McKinsey on the potential role for hydrogen in New Zealand, and are seeking partners for a proposed 600 MW green hydrogen export project in Southland.
- Ballance Agri-Nutrients is working with Hiringa Energy to develop hydrogen as a feedstock for its ammonia-urea production or for heavy transport, using wind generation and power electrolysers (electrolysis plant). Further information on this development is discussed in the Case Study on page 43 below.
- Hiringa Energy is working on a nationwide refuelling network to support a fleet of heavy vehicles such as trucking, as heavy vehicles have been identified as one of the more attractive use cases for hydrogen due to difficulties faced when electrifying this type of vehicle.

5 What is the problem?

There are sufficient reserves to meet New Zealand's gas demand. However, without sufficient ongoing investment years in advance of when the gas is needed, there is a real risk that not enough gas will be able to be delivered to major gas users, including electricity generators, during the transition out to 2030 and beyond.

Section 5 summary

We have identified two key issues that need priority attention in order to enable natural gas to play its part in the transition:

- There is a higher risk hurdle for investment in gas development and production in New Zealand than has previously been the case, which stakeholders have told us is largely due to:
    - uncertain gas demand
    - fewer opportunities to manage risk as the size of the industry declines
    - investors (in both production and demand) being unsure of the extent to whichh policy and regulatory levers are likely to be pulled that will change the economics of their investments.
- Insufficient commercial arrangements are committed to in advance to ensure availability of gas to provide deeper dry year cover for electricity until electricity is 100% renewable.

5.1 Key problem summary

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, and we agree. 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.

However, there was universal acknowledgment that the current supply situation meant that some users did not have sufficient certainty about gas supply for their operations. The tight market situation may continue into 2022-23 and the later part of the decade.

There are sufficient reserves to meet New Zealand's gas demand, without sufficient ongoing investment well in advance of when the gas is needed. However, there is a real risk that without that investment, not enough gas will be able to be delivered to major gas users, including electricity generators, during the transition to 2030 and beyond.

We have identified two key problems that need to be dealt with now in order to enable natural gas to play its part in the transition:

1. Investors' ability to commit capital is reduced and the risk premium attached to any investment is increased, creating a real risk that gas reserves and contingent resources in existing fields will not come to market and security of supply for electricity generation and for major gas users will be compromised during the transition to 2030 and beyond.

2. Commercial arrangements committed to in advance for electricity security of supply during dry years are insufficient, meaning that sufficient gas is not committed to being readily available to support electricity generation when it is needed most.

Together, these issues mean that further tools are required to enable gas to play its expected role in the transition.

5.2 Ability to commit capital

Through a transition period like the one we are in, change is inevitable and risk increases. When deciding where to commit a limited pool of capital, investors assess the relative economics of proposed investments factoring in a premium to reflect the expected risk and return. Lower-risk investments are easier to get across the line and require a lower rate of return. On the other hand, investors are less likely to commit capital to higher-risk investments and when they do, a greater return is required to reflect the increased likelihood of failure (and consequent loss of capital).

In relation to the gas development and production investment that New Zealand needs during the transition, there are three key factors that put it at the high-risk end of the spectrum and contribute to difficulties in committing the capital required.

5.2.1 Uncertain demand

First, demand for gas (and therefore investment into gas development and production) is affected by:

- concerns about customers, businesses or industries shutting down and uncertainty about the timing of some of these exiting the New Zealand economy
- a lack of clarity about what mechanisms are preferred to achieve decarbonisation and whether reduction in major users' gas use is expected to be prioritised over net decarbonisation overall
- concerns about costs making business uneconomic or uncompetitive
- a lack of confidence that gas supply will be available to meet demand.

5.2.2 Lower ability to manage risk

Secondly, while investors have always been aware of the risks involved in gas development and production and have developed mechanisms to manage and mitigate that risk, the risk profile has changed over recent years and traditional risk management mechanisms have become less available. For example, as the number of producing assets in New Zealand shrinks, there are fewer opportunities for diversification across a New Zealand portfolio; and with a higher risk profile, fewer partners are willing and available to share risk.

5.2.3 Policy and regulatory changes

Thirdly, investors (in production and demand) understand and expect that policy and regulatory levers that will inevitably be pulled through a transition will change the economics of their investments, but are unsure to what extent. This includes changes in both the energy and broader environmental and societal context – including, for example, resource management reforms impacting demand.

Participants acknowledge that the high-level overall desired direction for New Zealand's energy and broader carbon transition is clear. We also anticipate that the setting of the Government's emissions budgets and Emissions Reduction Plan due in May 2022 could provide some additional certainty around the timing and extent of the transition. However, we do not expect this additional certainty to give us the required confidence that sufficient and timely investment will occur, given:

- it is not expected to provide a great deal of granularity in respect of natural gas-related activities in New Zealand
- it cannot reduce the other risks described above.

5.2.4 Risk of insufficient investment

Because of these three factors, there is a higher risk hurdle for investment in gas development and production in New Zealand than has previously been the case: less capital is available for investing in this high-risk environment given competition with other potential (lower-risk) investments, including internationally; and a higher risk premium is attached to investment to compensate for the risks.

We consider that this leads to a real risk that insufficient investment will be committed to ensure that gas reserves and contingent resources in existing fields will not come to market and that security of supply for electricity generation and for major gas users could therefore be compromised during the transition out to 2030.

This becomes critical if the largest users are at risk of shut down, because they have a vital role in:

- providing the certainty of demand needed for producers to commit to funding development
- ensuring sufficient levels of gas demand remain in the system at both a gas field and system-wide level
- counterbalancing the potential variation in gas supply needed to support electricity demand due to unpredictable weather- and hydrology-dependent renewables by adjusting their level of demand as needed.

5.3 Commercial arrangements for electricity security of supply

Independent of upstream production investment, we see a gap in commercial arrangements committed to in advance to ensure gas supply is available for electricity generation when it is required to cover sustained dry periods. This is evident in Figure 1 on page 22 above, which shows a gap above available thermal fuel supply to meet demand in 2022 if it is a dry year.

Current operation and contracting appears to cover gas supply to cover the peaking and seasonal roles for thermal generation, but not the large volume of thermal fuel support required more infrequently to cover sustained dry periods. This could become more of an issue as the gas sector becomes smaller, unless there are increased incentives to shore up this support in advance. This seems to be at least partly due to a lack of clarity about the scale of the issue and how far in advance arrangements for increased supply or demand response need to be made.

This can result in constrained gas supply for electricity generators who are not sufficiently contracted precisely at the time when they most need to be able to generate electricity. Due to the nature of gas production, specifically the constraints on field flexibility (discussed in section 3.4 above), there is limited ability for gas fields to increase production in the short term to provide any additional gas unexpectedly required to cover sustained dry periods. Without appropriate incentives for electricity generators ensuring they have fuel supply arrangements contracted in advance to cover sustained dry periods, these needs cannot be fed through to the gas industry to ensure the necessary gas is available.

Unless or until another source of backup energy becomes available, in the current climate this means that demand response from major gas users is relied upon to enable the flexibility in the system needed to support electricity security of supply.

If this is planned in advance, it can work well, and Methanex acknowledged this role in its submission to our consultation paper:

> *"If Methanex had a stronger operation and was operating three plants at full rates, we could continue to play the role of New Zealand's battery over the coming decades as we transition towards 2050. If Methanex is not able to continue to operate in New Zealand, this battery which has existed for decades will leave New Zealand further exposed to a reduced industry without a backbone consumer to underpin development."*

However, when demand reduction is unplanned (as it was in 2021), it can have negative outcomes for New Zealand.

Winter 2021

During the sustained autumn/early winter dry period in 2021 when electricity prices were inflated, short-term gas availability for major users was compromised because, in those circumstances, electricity generators had a higher willingness to pay for gas, confident they would be very likely to receive a return from high electricity prices.

Major gas users could have been expected to have mitigated this risk by long-term contracting with gas suppliers. However, this period coincided with some gas users:

- not being in a position to contract for a significantly long period (particularly as they navigate the changes to their operations as they decarbonise over the coming years),
- being in the unfortunate position of having their existing long-term contracts come to an end precisely when supply was tightest, limiting the options for recontracting.

For example:

- Oji Fibre Solutions highlighted in its submission to the Consultation paper that, *"We face very high prices over the next 18 months with most of our natural gas supplies priced at the electricity replacement cost."*
- Refining NZ highlighted similar issues.

Many of the industrial gas users relied upon to perform this demand response are critical industries, with several having been given essential service designations to operate during the 2020 COVID-19 lockdown to ensure they could continue to produce materials that are critical to New Zealand's economy, such as steel (see Case Study below), wood and food products.

Case Study: NZ Steel

On 18 September 2020, a load-bearing strut on the Auckland Harbour Bridge was damaged when a strong gust of wind blew a truck into the bridge structure. Two of the bridge's eight lanes were closed until it could be repaired, with long delays and gridlock impacts on already congested Auckland traffic, and NZTA requesting people on the North Shore to work from home.

The Grade 350 L15 steel for the replacement strut was sourced and manufactured by New Zealand Steel (NZ Steel) at its Glenbrook Mill.

The bridge was fully re-opened on 6 October 2020, 18 days after the initial damage occurred. In a matter of days, NZ Steel was able to provide the necessary steel for the replacement strut, compared to imports which would have taken many weeks or months longer, especially considering delays to international shipping during the COVID-19 pandemic.

NZ Steel produces a large proportion of New Zealand's steel requirements, used in building and construction (e.g. roofing, cladding, framing), infrastructure, manufacturing, packaging and agriculture. The steel mill uses coal as a necessary reductant agent and consumes electricity and natural gas, with gas providing high temperature heat to the steel making process. Natural gas is used to preheat ladles for holding iron and steel and to reheat the steel slabs before they are rolled. Downstream finishing processes also use natural gas as an important part of the coatings drying process. NZ Steel also has a cogeneration plant, producing electricity from the off-gases and waste heat from the iron making process and improving the overall efficiency of the steel making process. This meets on average 60% of the site's electricity demand.

There are currently no commercially viable alternatives to gas in NZ Steel's processes due to the high temperatures required. Alternatives are being developed internationally for parts of the steel-making process (e.g. induction heating could be used to heat cool slab), but all rely on significant volumes of low-priced electricity (or hydrogen, which is produced using electricity).

In the meantime, until technological alternatives become commercial, NZ Steel is working to improve its internal efficiencies and thereby reduce the amount of CO_2 emitted for each tonne of steel produced. Unfortunately, elevated electricity and short-term natural gas prices (and, at times, availability) mean that NZ Steel has at times been forced to operate some parts of its plant at inefficiently lower levels to avoid incurring high energy costs. This was particularly acute in 2021 given the timing of NZ Steel's energy supply contracts coming up to renewal.

Lower steel production results in reduced availability of products for New Zealand's construction needs – and potentially increasing the construction sector's reliance on international imports in a time where international shipping can be delayed and worldwide demand for steel is high.

6 How can we smooth the transition?

We propose a relatively comprehensive work programme (including noting and proposing further development of some work that is already underway) that aims:

- to provide greater confidence to support the required investment in natural gas supply and flexibility, ensuring natural gas supply is able to meet required demand:
  - to support electricity generation until it is 100% renewable
  - to support industrial energy use as it transitions to net zero carbon by 2050
  - to meet the continued need for gas to supply the commercial, residential and agricultural 'mass market', albeit at reducing volumes
- to support the transition to more efficient and greener gas.

Section 6 summary

We consider that two key action areas could address the key problems outlined.

First, we propose a joint Gas Industry Co / MBIE workstream to develop a Gas Transition Pathway to provide the granular direction needed to support improved investment confidence.

Secondly, we recommend a set of three interrelated workstreams to improve commercial arrangements so that sufficient volume and flexibility of gas supply is in place far enough in advance to promote security of supply for electricity (covering both energy and capacity):

A A Gas Industry Co-led workstream focused on what gas producers, gas storage and major users can deliver to generators and major users over the medium to long term.

B A related focus on the critical role of planned demand response by Methanex in supporting electricity security of supply through the transition.

C The Electricity Authority considering current limitations to dry year cover in its response to any problems it identifies in relation to thermal fuel availability and security of supply in reviews it has underway.

6.1 Key actions

We consider that two key action areas could address the priority issues identified in section 5 above.

6.1.1 Gas transition pathway

First, clearer direction is needed so that gas sector participants will have the confidence to make the investments needed to ensure security of gas supply for both electricity generation and major users.

Throughout the investigation, sector participants expressed their strong desire to see and participate in the development of an Energy Strategy, or an Energy Accord where government, industry and consumers could agree a way forward for energy supply and use in New Zealand. We anticipate that a strategy may well be developed following the release of the Government's Emissions Budgets and Emissions Reduction Plan planned to be finalised in May 2022 (which will set the country's broader emissions reduction direction). However, the gas industry is seeking a level of granularity that we consider a broader energy strategy is unlikely to deliver.

Therefore, we see an urgent need for focus on what the transition pathway will look like for gas (both natural and replacement gases) in particular, given the strategies for electricity and coal are relatively clear. This could then feed into a broader Energy Strategy if the Government chooses to pursue one.

To do this, we recommend that a workstream be established to develop a Gas Transition Pathway to provide granular direction and thereby reduce some of the risks described in section 5.2 above, supporting an improved ability to make the investment needed in gas development and production. We propose this workstream would be jointly managed by Gas Industry Co and MBIE and involve input from industry and a range of stakeholders.

A critical part of this pathway will be considering how to ensure there is continued commercial support for production investment during the transition. For example, it will be important to develop a universal (cross-government) and specific understanding of the factors that will drive petrochemical businesses' decisions about whether to remain operating in New Zealand as they transition to more efficient and greener production, given their critical role. Such transitions are already underway, with Ballance Agri-Nutrients working with Hiringa Energy to transition its natural gas feedstock over time to hydrogen sourced from green electrons, as described in the case study below.

6.1.2 Improving commercial arrangements supporting electricity security of supply

Secondly, we also recommend that the following set of three interrelated workstreams will improve commercial arrangements so that sufficient volume and flexibility of gas supply is in place far enough in advance to promote security of supply for electricity (covering both energy and capacity).

This should in turn provide increased predictability for major gas users' operations, since they will be less likely to experience unplanned curtailments to their gas supply or pricing volatility.

A Gas supply

In the first of these interrelated workstreams, we envisage that Gas Industry Co would focus on what gas producers and major users have agreed to and can deliver to generators and major users over the medium to long term. This could include:

- commissioning more regular gas supply and demand studies (e.g. to be carried out and published annually following release of MBIE reserves data) and publishing them on its information portal
- using the information from the studies to identify where there might be gaps that industry needs to address
- assessing the likely costs and availability of options to support security of supply, including to enable more flexible gas supply to meet the increasingly weather-dependent electricity system, including:
    - gas storage, provided the gas supply is available to do this
    - providing additional planned demand response (see B below)
    - unplanned demand diversion
- facilitating arrangements between gas industry participants as it has been able to do this year to resolve some critically tight supply situations.

We received feedback that the gas supply and demand study we commissioned as part of this investigation (discussed in section 4.1 above) provided vital information and much needed insight to the gas and broader energy sector – both in relation to the near term situation and the outlook over the next 15 years. Gas Industry Co sees a real benefit to carrying out and publishing gas supply and demand studies more regularly, as part of enabling a better understanding of where the gaps might be and how to fill them.

As the energy sector decarbonises, we expect greater demands for increasingly flexible supply of gas, largely driven by the changes to the composition of the fuel supply mix for electricity. Demand for thermal electricity generation will become increasingly intermittent as generators' operating profiles evolve, with the proportion of weather-dependent renewable generation increased and thermal generating plant decommissioned. We anticipate this will see an increased need for backup solutions, which could include additional gas storage or planned demand response.

B Planned demand response

Alongside gas storage, planned demand response by Methanex is likely to be readily available and at large enough volumes to enable the flexibility in the system needed to provide the security of supply required. In the medium to longer term as the transition progresses, large-scale planned demand response can support security of supply without the challenges of finding additional gas to fill storage or of developing a new LNG import industry for New Zealand.

The second proposed workstream in this set recognises the criticality of Methanex's role.

An important early step will be Gas Industry Co facilitating discussion between relevant stakeholders (e.g. Methanex, Genesis, MBIE, consenting authorities, the Electricity Authority) to develop a specific understanding of the factors that will drive petrochemical businesses' decisions on whether to remain operating in New Zealand as they transition to more efficient and greener production, given their role.

This needs to happen as a matter of priority, in order to ensure that any recommendations and actions can be made in time to support reliability in winter 2022 (when we expect gas supplies to be tight again, as noted in section 4.1.1 above) and to allow for any additional investment that may be required.

A key question will be who ultimately pays for any planned demand response and how that is enabled. One option is a simple contractual formalisation of the demand response arrangements. In our discussions, some stakeholders raised other potential mechanisms emerging overseas that could support this, such as a tradeable certificate of guaranteed energy provision, or a regulatory requirement for generators or energy suppliers to show how they will ensure demand from their customers is met or reduced during tight supply situations.

C Reviews of electricity market operation and competition

Lastly, we have identified a need for improved commercial arrangements to be made in advance to support dry year cover for electricity security of supply. The Electricity Authority has a number of workstreams underway to review arrangements in the electricity wholesale market, as they relate to security of supply and competition. These include:

- a review of the electricity industry's response to the dry hydro sequence and tight gas market in 2021
- phase 2 of the Authority's review of the events of 9 August 2021
- the Authority's electricity wholesale market competition review.

We anticipate that the review of the response to the dry hydro sequence in 2021 will cover, in particular, the arrangements for fuel supply to support thermal (both gas and coal) generation in future dry years and current limitations to these arrangements. This should support better understanding of what is required from the gas sector to ensure security of electricity supply and is particularly important given the expected change in gas demand patterns to support an increasingly weather-dependent electricity system.

This will in turn feed back into workstream A above, given we expect that complementary physical solutions may be required to ensure gas can be delivered more flexibly. These could include gas storage (discussed in section 4.4.1 above), or planned demand response.

Case Study: Ballance Agri-Nutrients

Ballance Agri-Nutrients owns the country's only ammonia-urea manufacturing plant, which is located at Kapuni in Taranaki. The plant uses natural gas to convert atmospheric nitrogen to ammonia and then to urea. Ballance's first business priority is the reliable supply of nitrogen to its customers as failure to supply has a significant impact on farm productivity, animal wellbeing and New Zealand's farm exports and GDP.

As well as being critical to all aspects of agricultural food production, urea is also a key ingredient in other applications such as the manufacture of particleboard and MDF. Ballance uses natural gas as a feedstock into its ammonia-urea production as well as a fuel for high temperature processing.

While Ballance also uses electricity in its processes:

- electric reforming technology is not yet commercially available
- electric boilers don't provide the flexibility and superheated temperatures required for ammonia-urea production
- any critical processes are gas driven, given voltage disturbances on the electricity grid (even those with a short duration or a long distance away) have the potential to disrupt operations for extended durations.

Looking to the future, Ballance is taking steps to decarbonise its operations while maintaining reliability. This will include large-scale transitioning of its natural gas use to green hydrogen, but this will take time and funding, and requires a reliable supply of natural gas in the meantime.

Ballance is working with Hiringa Energy to develop a green hydrogen plant near the Kapuni ammonia-urea plant. The project will produce hydrogen from an electrolyser that is powered by four large wind turbines. When the wind is blowing, hydrogen produced by the generated electricity can act as additional feedstock for ammonia-urea production, with natural gas supplementing feedstock supply when the wind is not blowing. Natural gas enables stable operation conditions in the plant and complements the intermittent availability of green hydrogen. The wind turbines will also provide renewable electricity directly to the Ballance plant.

It is estimated production of green ammonia-urea will offset up to 12,500 tonnes of carbon emissions and avoid the import of 7,000 tonnes of urea from the Middle East and Asia, eliminating the equivalent amount of CO_2 as taking 2,600 cars off the road.

6.2 Other workstreams needed to support the transition

6.2.1 Information

Our investigation has identified that better, and more timely information will help enable participants and users to predict and plan better. We propose that a group of four main information-related workstreams be continued or established to support the transition.

Gas Industry Co Information Disclosure workstream

Gas Industry Co commenced an information disclosure workstream in 2018 and has already successfully implemented some changes, such as the outage disclosure web page. We are continuing to progress the remaining items in this workstream, including assessments of major user outages and a weighted average gas price.

Other developments in the workstream include setting up the beginnings of an information portal on Gas Industry Co's website. To date, this includes gas production and consumption charts, which have had positive feedback. We plan to include further supporting analysis and information about the gas sector on the portal over time.

Submissions to the Consultation Paper highlighted the fine balance around the amount of information that should be disclosed, emphasising that some information may be too commercially sensitive to release and that some information that participants are seeking may not exist. Gas Industry Co will continue to take these considerations into account in future information disclosure recommendations.

Reserves data

In our discussions with industry, the publication of MBIE's petroleum reserves data came up many times. Many stakeholders highlighted their concerns with the infrequency and significant delays in the publication of this data. As the industry is in a time of rapid change, it is important for stakeholders to have access to the most up-to-date information in order to inform their decision making.

We recommend that improvements are made to the reserves data process and publication, so that:

- the suite of data collected and published is expanded to include 1P production profiles, a description of reported Contingent Volumes, and demand side information (already collected by Gas Industry Co)
- the information is published (at least in provisional form) much more quickly after being provided by industry - with the expectation that it would be updated and finalised once the appropriate quality checking processes are carried out
- consideration is given to more frequent (e.g. six-monthly) collection and publication of data.

Regular gas supply and demand studies

As part of this Gas Market Settings Investigation, earlier this year Gas Industry Co commissioned and published a gas supply and demand study focused on both the near-term situation and the outlook over the next 15 years. We received feedback that this provided vital information and much needed insight to the gas and broader energy sector.

Gas Industry Co sees a real benefit to carrying out and publishing gas supply and demand studies more regularly. We plan to commission and release them annually, commencing the studies following the publication of MBIE data, which is an important input.

Improving understanding of risks

From our discussions with the wider energy industry during the course of this investigation, it has become apparent that the risks around gas supply are not well understood in the wider energy sector.

Historically surplus gas production from Maui and other producing fields have provided the flexibility to address these risks (for example fields had greater ability to ramp up production in response to declining supply from another field), so industry participants have not needed to be concerned that gas might not be available for delivery when needed. Now that fields are in their decline phase and the gas supply and demand balance is much tighter, it is vital that industries that utilise gas, as well as associated industries such as electricity generation (including those who do not use gas themselves), understand the risks involved in delivering gas and can plan around them.

With good understanding of risks, participants in the gas and electricity sectors (including energy users) will be better able to appropriately plan ahead and balance their security of supply needs.

In this workstream, Gas Industry Co intends to work with industry and others to ensure the major risks to secure gas supply and their impact are better understood. This could include:

- consideration of:
  - how major risk information should be disclosed, interpreted and published
  - whether formal risk assessments (similar to electricity risk curves) would be a useful tool to assist those businesses for which gas supply is a relatively small part of their overall operations to more readily factor those risks into their commercial decision making
- publishing information on Gas Industry Co's portal about how the New Zealand gas system works and generic upstream production risks
- publishing all historic production data on the portal.

6.2.2 Regulatory framework for gas pipelines

The regulatory framework for gas pipelines in Part 4 of the Commerce Act 1986 was established in 2008 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. We have had feedback from a wide range of stakeholders (including pipeline owners, regulators, upstream participants and gas users) that it may not be appropriate for an industry undergoing transformational change, where consumers have an interest in the maintenance of the network for security of supply.

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. The same issue applies to gas distribution.

The Commerce Commission has work underway in the context of its upcoming price-quality path reset, input methodology review, and targeted information disclosure review to consider whether the settings within the current framework are fit for purpose. The Commission 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 could be enhanced by involving a wider group of regulators as well as sector participants.

In addition, stakeholders are also interested in the bigger question of whether Part 4 itself is fit for purpose to regulate gas pipelines during an extended period of disruptive change.

We agree that this question needs to be addressed and therefore recommend that a formal review of Part 4 of the Commerce Act and its application to gas networks is undertaken, including joint work by MBIE and the Commerce Commission considering whether:

- the current framework is fit for purpose, in the context of the Commerce Commission's upcoming price-quality path reset, input methodology review, and targeted information disclosure review
- changes are needed to the overall regime in an industry undergoing transformational change, where all energy sector stakeholders down to end consumer level have an interest in the maintenance of the network for security of supply.

6.2.3 Continued use of gas where alternatives are not suitable

During the course of this investigation, we have heard that gas 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 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, and some will need the properties of gas to support their operations for much longer.

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 – see the Southern Fresh Case Study below).

In order to ensure support for a lower carbon future with gas playing its part where it is needed, we propose a workstream considering how gas can support New Zealand's energy needs that cannot be met by electricity. We envisage this would include:

- considering how best to enable the development of 'green gases' including hydrogen and biofuels, and whether this should be accelerated (with a pathway to be included in the proposed gas transition pathway referred to in section 6.1.1 above)
- looking at whether appropriate incentives are in place for those who need to use gas to avoid, and where that is not possible, to at least reduce their emissions (e.g. ensuring that reductions in emissions such as greenhouses using CO_2 are counted under the ETS)
- exploring the viability of emissions capture and storage in New Zealand.

We see these workstreams as inter-related and consider there would be value in stakeholders (including both private sector and government) working collectively to progress all of them alongside each other. There are several examples of this 'cluster' model internationally, including in Australia and Scotland.

Carbon capture and storage (CCS) has previously been assessed as uneconomic in New Zealand, generally because there are no sites of sufficient scale to justify the investment. During our investigation, a number of parties raised broader 'emissions capture' as a concept, with resulting carbon capture and storage as an associated benefit. Under this concept, rather than filtering and sequestering the CO_2 emissions only, all emissions from a site are captured and stored. The economics are improved without the need for the additional filtering processes that pure CCS requires, and steadily increasing carbon prices further increase the desire to find solutions to address CO_2 emissions that cannot be otherwise reduced.

Case Study: Southern Fresh

Southern Fresh is a primary food producer and processor in the Waikato that grows salads, herbs and specialty baby vegetables. It recently built an indoor farm to grow its produce hydroponically. This is a key solution for Southern Fresh to meet the Waikato Regional Council's Healthy Rivers objectives – covered cropping helps to resolve leeching issues that are difficult to address in regular outdoor cropping. This indoor farm also uses 20 times less water than outdoor growing, avoids any damage to existing soil, requires minimal use of pesticides and fungicides, and maximises land use as annual production from a single hectare of indoor hydroponic growing is equivalent to 40 hectares of open field production. One hectare of glasshouse is currently operational, with plans to expand into another hectare that has already been built.

As well as providing an opportunity to improve land and water use, the farm has also been able to reduce New Zealand's reliance on (and related emissions from) imports - Southern Fresh now produces nearly all of the basil used to make all of New Zealand's commercially produced pesto, replacing imports from Fiji which were previously the main source.

The indoor farm is heated by a high efficiency natural gas boiler, which maintains a constant warm temperature for crop growing and also provides a key input of CO_2 to encourage plant growth, increasing yields by over 30% and at the same time preventing CO_2 emissions being released. Currently this use of carbon is not considered under the Emissions Trading Scheme (ETS). Other cropping farms (including those that use geothermal resources for heating) purchase CO_2 to deliver into their glasshouses at a high cost.

Southern Fresh has two major opportunities to further reduce its CO_2 emissions by removing emissions intensive technology and improving efficiency of energy use - and at the same time continue to improve its productivity, land and water use.

- The gas boiler has sufficient capacity to heat 6 hectares of glasshouse (the two already built plus an additional 4 hectares that Southern Fresh holds resource consents to build).
- Southern Fresh also uses three coal boilers on a neighbouring site to heat four hectares of glasshouse built in the 1980s for growing flowers. As part of an upgrade to those glasshouses, Southern Fresh has been considering replacing the coal boilers (which are polluting, inefficient and create an unpleasant working environment) with a gas boiler similar to the one mentioned above. This would vastly improve efficiency and enable the capture and use of CO_2 and waste heat.

However, these projects would require substantial capital investment, including in the gas pipeline to deliver the additional gas that would be required. Southern Fresh told us that uncertainty around future natural gas supply and regulations means that it is not confident it will be able to achieve a reasonable return on the investment required.

In addition, it does not view alternative energy sources as viable or sustainable:

- New electricity (or, if it becomes viable in time, hydrogen) fueled boilers could provide the heat needed, but these would require (a) significant upfront capital investment and (b) separate purchase of CO_2, which would need to be captured and delivered from another source and priced in.
- Southern Fresh has investigated using wood chip boilers, but has "*serious concerns to this being a sustainable and cost-effective source of energy in the long-term due to the high risk [of] supply shortages nationally*" (from its submission to the Climate Change Commission).
- Biomethane could potentially provide what these greenhouses need in time (both in terms of the heat source and the CO_2) but requires a transition plan to maintain supply of natural gas until it becomes available in sufficient quantities.

6.2.4 Support for tightening supply situations

As the transition progresses, there is a risk that tight gas supply situations like we have experienced in 2021 will become more common. At the same time, the shrinking size of the industry and reduction in diversity of supply will make it harder to provide a buffer for such situations.

Some users may exit New Zealand as a result, and others may seek regulatory relief in order to enable them to continue operating. As supply declines, decision makers need to be confident that changes to the make up of the sector are occurring on the basis of the most efficient and socially responsible allocation of resources. One mechanism to ensure this is happening is the ETS, which encourages increasingly lower emissions activities and thereby theoretically incentivises a move away from the lowest value use of carbon emitting processes first. Industrial allocations under the ETS have an important role in addressing this socially responsible allocation of resources by supporting industries that supply essential goods to New Zealand.

Given these challenges, we recommend Gas Industry Co and MBIE work together to consider whether any additional mechanisms (or changes to/clarifications of existing mechanisms) are needed to ensure gas is available to industrial users in specified, unexpected tight situations. This could cover a wide spectrum of possible responses, from allowing commercial arrangements to play out through to significant intervention where required to ensure the desired policy outcomes.

For example, this could take the form of:

- simply leaving the outcomes to be determined by commercial arrangements, with market participants able to enter hedging or insurance arrangements to cover risks where they see value in doing so
- enabling and encouraging a more fulsome use of ETS tools as the main mechanism to encourage increasingly lower emissions activities
- ensuring there are no barriers to major users accessing gas storage
- prescribing requirements for gas storage to ensure that high value gas users have a back up
- providing for a gas seller of last resort at a known (expensive) price in prescribed situations.

Appendices

Appendix 1 – Minister's request

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

Appendix 2 – Work programme

What is the problem?	How do we propose to deal with it?
There is a higher risk hurdle for capital investment in gas production and development in New Zealand than has previously been the case. This leads to a real risk of insufficient investment to support security of gas supply for electricity generation and other major users during the transition. The long-term, high-level goal is clear but the pathway to get there is not.	Develop a Gas Transition Pathway to support improved investment confidence. We propose this workstream would be jointly managed by Gas Industry Co and MBIE and should involve input from industry and a range of stakeholders. This could feed into a broader Energy Strategy and will enable early focus in an area where it is needed (given the strategies for electricity and coal are relatively clear). A critical early step will be Gas Industry Co facilitating discussions between relevant stakeholders (e.g. Methanex, Genesis, MBIE, consenting authorities, the Electricity Authority) to develop a specific understanding of the factors that will drive petrochemical businesses's decisions about whether to remain operating in New Zealand as they transition to more efficient and greener production, given their critical role.
There is uncertainty in commercial arrangements committed to in advance to ensure gas supply is available for electricity generation and major users when it is required, particularly for dry winters.	A set of three interrelated workstreams to improve commercial arrangements so that sufficient volume and flexibility of gas supply is in place far enough in advance to promote security of supply for electricity (covering both energy and capacity): A. A Gas Industry Co-led workstream focused on what gas producers and major users have agreed to/can deliver to generators and major users over the medium to long term, including carrying out more regular supply and demand studies; assessing the likely costs and availability of gas-related options to support electricity security of supply; and potentially facilitating arrangements between industry participants where necessary. B. A related focus on the critical role of planned demand response by Methanex given it is likely to be readily available and at large enough volumes to enable the flexibility in the system needed to support electricity security of supply through the transition – and without some of the challenges facing other options in the medium to longer term. C. The Electricity Authority considering current limitations to dry year cover in its response to any problems it identifies in relation to thermal fuel availability and security of supply in its reviews of the energy industry's management of the 2021 dry hydro sequence and tight gas market; the events of 9 August 2021 (the Phase 2 review); and electricity wholesale market competition.

What is the problem?	How do we propose to deal with it?
Calls for better, more timely information to help enable participants and users to predict and plan better.	A group of four main information-related workstreams are continued or established to support the transition: a. continuation of Gas Industry Co's information disclosure work (acknowledging that some information that participants are seeking may not exist and some may be too commercially sensitive to release) b. earlier release of MBIE's annual reserves data, with the addition of 1P production profiles, a description of reported Contingent Volumes, and demand side information (already collected by Gas Industry Co), and consideration given to more frequent (six-monthly) collection and publication c. more regular gas supply and demand studies (e.g. to be carried out and published annually following release of MBIE reserves data) d. work to ensure the major risks to secure gas supply and their impact are better understood (e.g. considering how major risk information should be disclosed, interpreted and published; considering whether formal risk assessments (similar in authority to electricity risk curves) would be a useful tool; publishing information on Gas Industry Co's portal about how the New Zealand gas system works and generic upstream production risks; publishing all historic production data on the portal).
The regulatory framework for gas pipelines was established for a different market context and may not be appropriate for an industry undergoing transformational change, where consumers have an interest in the maintenance of the network for security of supply.	Review of Part 4 of the Commerce Act and its application to gas networks, including joint work by MBIE and the Commerce Commission: a. considering whether the current framework is fit for purpose, in the context of the Commerce Commission's upcoming price-quality path reset, input methodology review, and targeted information disclosure review (currently underway by the Commerce Commission) b. considering whether changes are needed to the overall regime in an industry undergoing transformational change, where all energy sector stakeholders down to consumer level have an interest in the maintenance of the network for security of supply.

What is the problem?	How do we propose to deal with it?
In many cases, alternatives to gas (including electricity): • are not suitable • are not available, or not available in sufficient quantities to meet expected timeframes • simply cannot do what natural gas can for their processes and businesses, or would lead to considerably less efficient outcomes. There will still be a need for natural gas (as modelled by the CCC and others), and it will emit carbon even with improved efficiencies. Tools are needed to negate/offset this.	In order to ensure support for a lower carbon future with gas playing its part where it is needed, we propose a workstream considering how gas can support New Zealand's energy needs that cannot be met by electricity. We envisage this would include: • considering how best to enable the development of 'green gases' including hydrogen and biofuels, and whether this should be accelerated (with a pathway to be included in the proposed gas transition pathway) • looking at whether appropriate incentives are in place for those who need to use gas to avoid, and where that is not possible, to at least reduce their emissions • exploring the viability of emissions capture and storage in New Zealand. We see these workstreams as inter-related and consider there would be value in stakeholders (private sector and government) working collectively to progress them alongside each other. There are several examples of this 'cluster' model internationally, including in Australia and Scotland.
As the transition progresses, there is a risk that: • tight gas supply situations like we have experienced in 2021 will become more common • the shrinking size of the industry and reduction in diversity of supply will make it harder to buffer. Some users may exit New Zealand as a result, and others may seek regulatory relief in order to enable them to continue operating. As supply declines, decision makers need to be confident that changes to the make up of the sector are occurring on the basis of the most efficient and socially responsible allocation of resources.	A joint Gas Industry Co/MBIE workstream considering whether any additional mechanisms (or changes to/clarifications of existing mechanisms) are needed to ensure gas is available to industrial users in specified, unexpected tight situations. A response could take several different forms: • simply leaving the outcomes to be determined by commercial arrangements, with market participants able to enter hedging or insurance arrangements to cover risks where they see value in doing so • enabling and encouraging a more fulsome use of ETS tools as the main mechanism to encourage increasingly lower emissions activities • ensuring there are no barriers to major users accessing gas storage • prescribing requirements for gas storage to ensure that high value gas users have a back up • providing for a gas seller of last resort at a known (expensive) price in prescribed situations.

Appendix 3 – Current arrangements

The New Zealand gas industry today

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.

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

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 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.

Up to 18 PJ of gas can be stored in the Ahuroa underground storage facility to be used when needed.

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.

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 basis (with no publication of prices or terms).

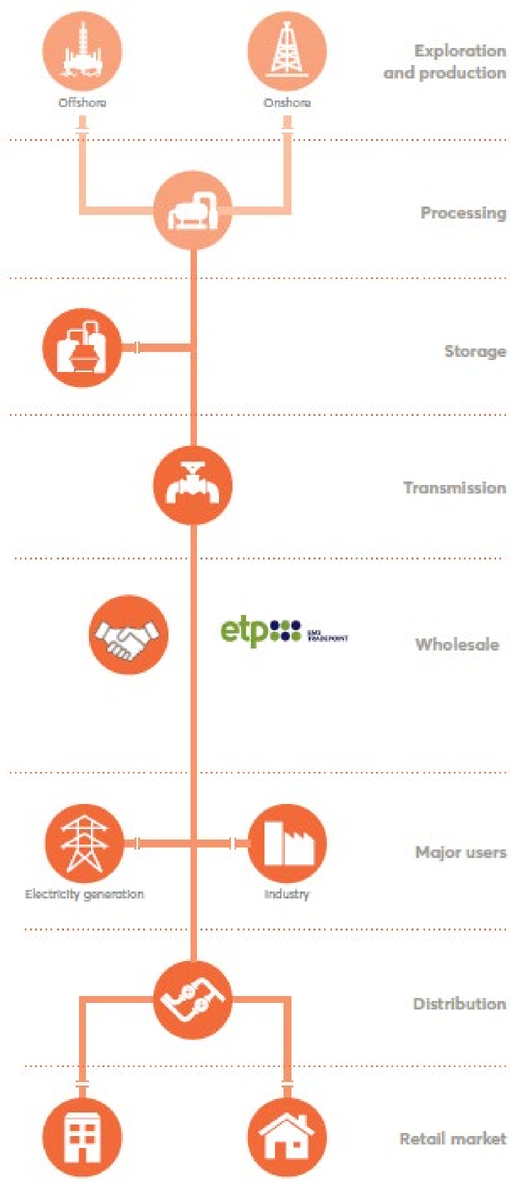
A commercial trading platform, emsTradepoint, was established in 2013 and provides a market-based transmission pipeline balancing regime as well as a small spot market for gas supply.

Some large users (petrochemicals, large industry and electricity generators) contract directly with producers.

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.

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

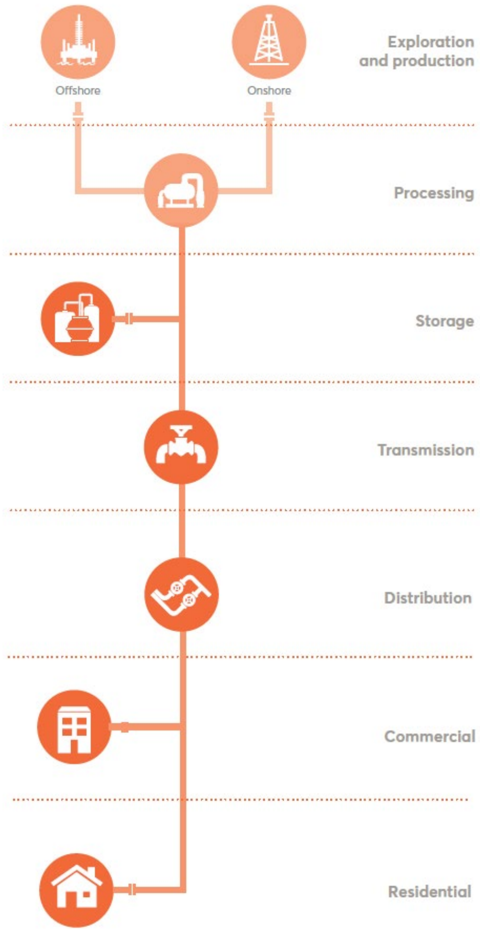
While participant led, New Zealand's gas industry is subject to a range of government policy and governance measures, which are designed to ensure gas is delivered to consumers in a safe, efficient, fair, reliable and environmentally sustainable manner. All aspects of the gas industry, from drilling 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 (750 MW from the Rankine units 1, 2 and 4, which can also be fuelled with coal; 385 MW from unit 5; 48 MW from unit 6, which can also be fuelled with diesel)
- Taranaki Combined Cycle (377 MW, which will require major refurbishment soon as it reaches its operational hours limit)
- Stratford (210 MW peaking)
- Junction Road (100 MW peaking)
- McKee (100 MW peaking)
- Mangahewa (9 MW 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 300 MW of capacity at:

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

About Gas Industry Co

Gas Industry Co 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
- oversee compliance with, and review such arrangements.

Gas Industry Co 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.

+64 4 472 1800 • info@gasindustry.co.nz • www.gasindustry.co.nz
Level 8, The Todd Building, 95 Customhouse Quay, PO Box 10 646, Wellington 6143

Gas Industry Co.