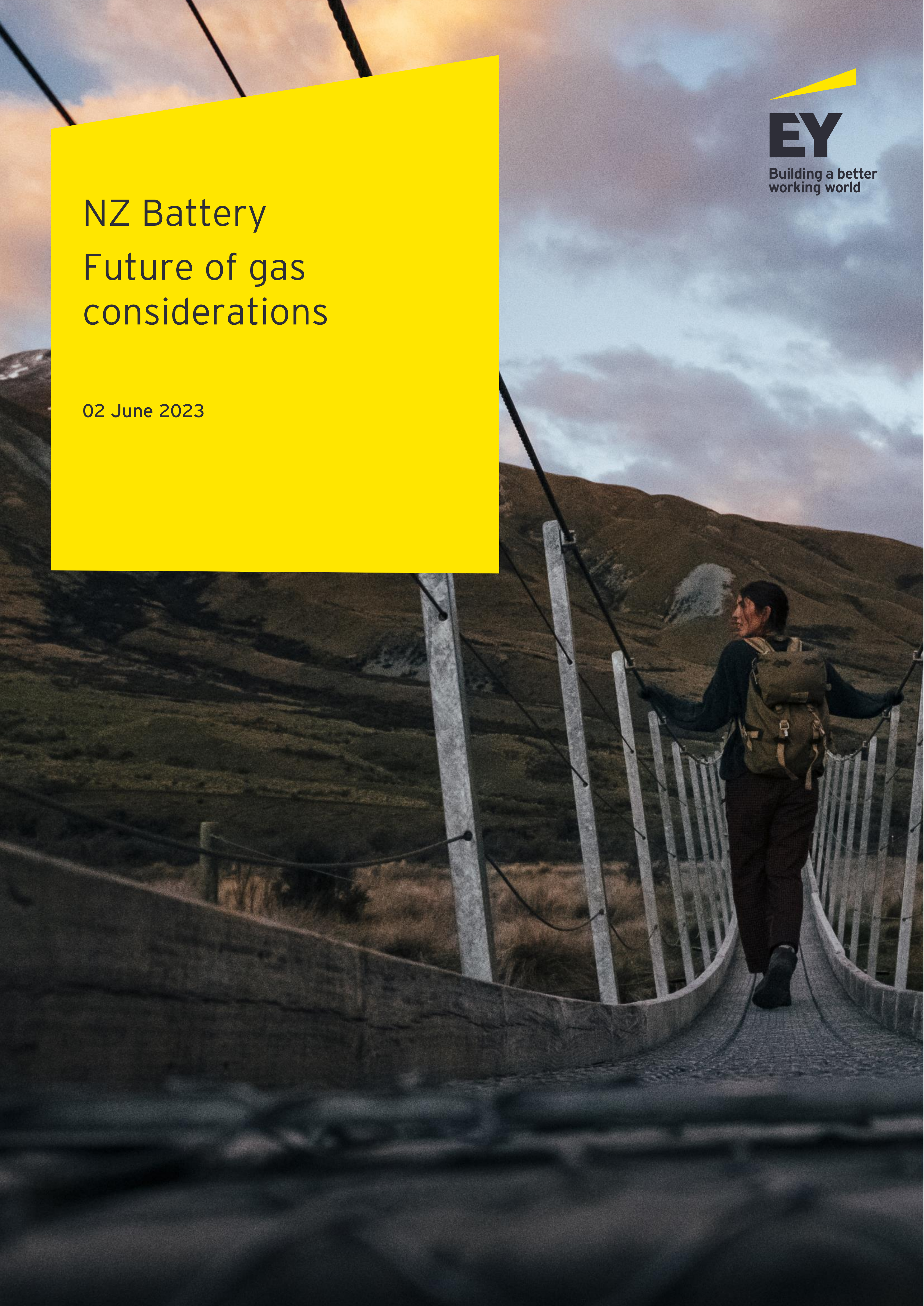

NZ Battery

Future of gas considerations

02 June 2023

EY
Building a better working world

Disclaimer - Purpose of our report and restrictions on its use

This report was prepared on your instructions solely for the purpose of supporting the Ministry of Business, Innovation and Employment (MBIE) to conduct research on the issues and considerations associated with using a fossil (gas) peaker scenario as a comparator in the New Zealand Battery Detailed Business Case (DBC). The report should not be relied upon for any other purpose. In carrying out our work and preparing our report, we have worked solely on the instructions of MBIE and for MBIE's purposes. This report was developed from information from modelling and studies completed to date by the NZ Battery project team, other reports provided by MBIE and some limited publicly available information. However, this is not intended to be a comprehensive review of all publicly available information.

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Our work has been limited in scope and time and we stress that a more detailed report may reveal material issues that this report has not.

Contents

1. Introduction

1.1 Background

In the NZ Battery Indicative Business Case (IBC) the counterfactual used to compare investment options against was a 100% renewable electricity generation overbuild scenario. This was appropriate given the context of the project's objective to provide a pathway to 100% renewable electricity, and the Government's stated ambition for reaching 100% renewable electricity by 2030. In this way, the IBC counterfactual created the ability to assess the ability of the different NZ Battery options to achieve 100% renewables on an equal footing. However, for the Detailed Business Case (DBC) it will be important to better understand what is likely to happen in the absence of an NZ Battery.

1.2 Why we need to consider a fossil peaker scenario

In order to assess any potential NZ Battery investment in the DBC, it is critical to develop a detailed understanding of what would likely happen without an NZ Battery investment (i.e. the counterfactual). This is not necessarily the same as a 'Do Nothing' scenario, particularly given the work underway by MBIE through the Electricity Market Measures team, and the Electricity Authority through the Market Dynamics Advisory Group, which is considering the potential changes needed to the electricity system to support the energy transition.

While there is significant uncertainty as to what may occur in the absence of an NZ Battery investment, there is general consensus that the electricity market as currently designed is unlikely to support a transition to 100% renewable electricity in the short to medium term. This view is consistent with The Future Is Electric report commissioned by several participants from the electricity sector which suggested that while it is possible to reach 98% renewable electricity by 2030, 100% would be sub-optimal before 2040 and pose resilience risks[1]. Even under these scenarios, the report notes that policy, regulatory and market reforms are still required.

This consensus view suggests that, in the absence of a coordinated intervention such as NZ Battery, fossil fuels will continue to play a role in the electricity system. This role would likely include both supporting periods of peak demand when renewable generation is low, as well as providing dry year cover.

It is generally assumed that the fossil fuel which remains in the electricity system is likely to be gas-fired generation, which can more easily scale its generation output than coal generation. Moreover, it is generally assumed that increasing carbon prices will significantly disincentives the use of coal for electricity generation in the short-medium term. However, ensuring sufficient volumes of gas and the supporting infrastructure and storage is available is likely to become more complex and uncertain as decarbonisation efforts reduce the consumption of gas in the broader economy. Being able to articulate these complexities and uncertainties will be critical in defining a credible counterfactual to assess any NZ Battery option against. This report aims to explore and better understand these complexities and uncertainties and identify what may require further investigation through the DBC.

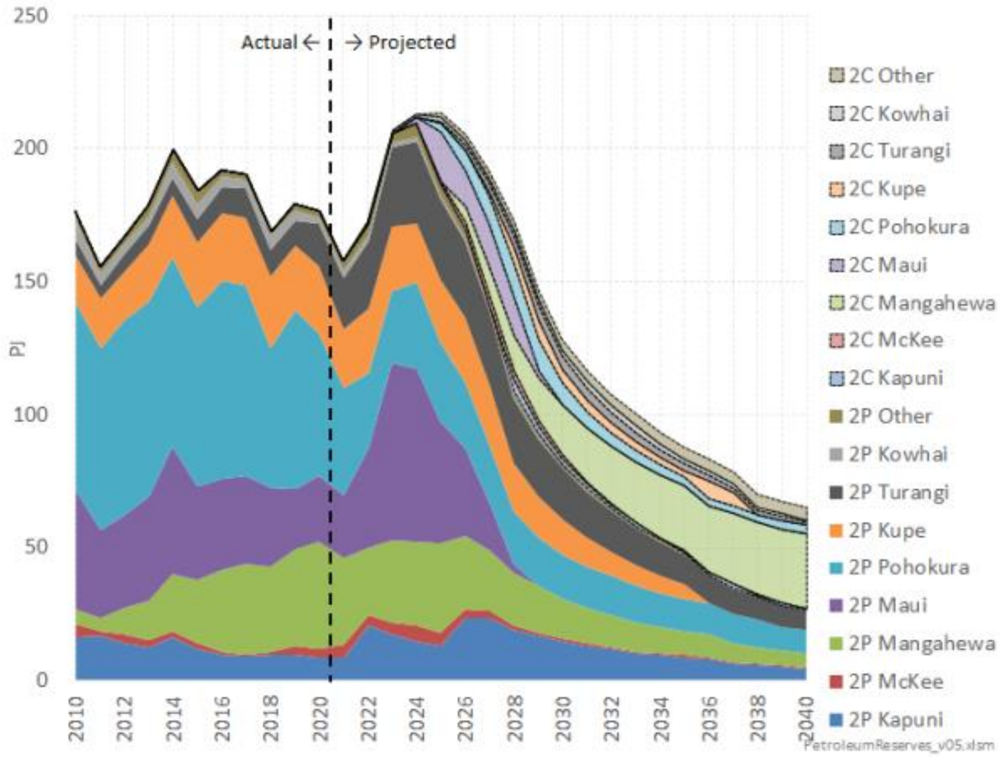
[1] BCG – The Future Is Electric

2. Current gas supply/demand and future demand assumptions

2.1 Supply

Gas supply in New Zealand is exclusively from domestic sources. All producing fields are in Taranaki; following a government decision in 2018 no new exploration permits outside onshore Taranaki are being issued. New Zealand produces up to 500 TJ of energy from gas each day - about 167 PJ a year[2] - from six main natural gas fields (Pohokura, Maui, and Kupe offshore and Mangahewa, Turangi, and Kapuni onshore) and another twelve smaller fields.

Projected production profile by field including simple development of 2C resources[3]



While noting that these are estimates only and that actual reserves available can't be known with certainty, this data suggests that there is sufficient gas 'in the ground' to meet mass market, industrial and power generation demand until at least 2035. Out to 2027, that production could come largely from existing reserves but beyond that point is likely to require the development of contingent resources[4] (i.e. gas resources which are not currently considered commercially viable).

Gas reservoirs are natural systems and tend to operate well in steady state production as the gas, oil and water mix are driven to the surface over time by the difference between subsurface and surface pressure. Production rates are largely governed by the permeability of the reservoir. Increasing production can be achieved but care needs to be taken that this does not cause too much water to be driven to the surface. It should be noted that the Maui field was an exception as permeability is

[2] MBIE - Petroleum Reserves petroleum-reserves.xlsx (live.com)
[3] Concept Consulting Report – Gas supply and demand projections
[4] Petroleum Resources Management System – Revised June 2018 (v. 1.03)

orders of magnitude that of onshore reservoirs[5]. This feature gave the operator an extraordinary ability to 'ramp up' and 'ramp down' production. However, this 'swing' capacity is atypical. Gas producers generally size production capacity based on the steady rate needed to meet demand, which is usually less than the full potential well production capacity. They are therefore unlikely to oversize production capacity but rather will use intraday storage in the gas pipeline (line pack) or gas storage facilities as 'gas sinks' to maintain steady production. Moreover, as there is a very limited spot market for gas, producers are unlikely to develop additional capacity speculatively to serve the spot market.

Gas supply is capital intensive – requiring annual investment of around $200m in upstream production facilities with the current industry scale[3] – and producers need certainty of demand to make this investment.

2.1.1 Key findings

Gas supply is likely to be sufficient for future scenarios, but demand signals need to be sufficiently certain to encourage investors. Gas is produced best at steady state and additional production capacity, or 'swing' is unlikely to be developed both due to economics and physical reservoir capabilities without additional incentives or intervention.

2.2 Infrastructure

Gas produced in Taranaki is transported throughout the North Island via the transmission network, with large users taking gas directly from the network; smaller users take gas from distribution networks in towns and cities. The gas transmission system has the capacity to transmit around 500 TJ/day and has operational linepack of 330 TJ when the Mokau compressor station is operating (280 TJ Mokau off). Available daily swing volume in the pipeline is in the order of +/- 25 TJ[6] due to the operational pressure regime of the pipeline.

Gas is also held in storage in the Ahuroa reservoir, which is New Zealand's only current underground gas storage facility. It is unregulated and owned by Firstgas Group. It allows its contracted users, Contact Energy and Nova Energy, to store gas produced or acquired for later use. This is a former gas reservoir which was re-purposed to store up to about 18 PJ of gas plus 4 PJ of pad gas. Injection and withdrawal capacity is 65 TJ/day. At low volumes of stored gas withdrawal capacity is reduced due to lower pressure support. Consequently, an additional 6 PJ of pad gas is in the reservoir which acts to support pressure. In December 2022 it was revealed that storage capacity had reduced to between 10 and 12 PJ and 4 more PJ had been converted to pad gas – bringing the working storage volume to 6-8 PJ on a P50 basis. Pad gas will be recovered at low rates at the end of facility life but cannot be called upon prior to end of facility life. The change in storage volume has been identified as being potentially to be due to water ingress. This issue is being managed through a change to the operating regime to reduce further impacts.[7]

Operationally the gas transmission and distribution systems can function with lower throughput volumes but there are risks of greater drop out of contaminants (due to lower flow velocities) and operational/maintenance issues that would accompany lower throughput (e.g. difficulties in cleaning lines and potential requirements to reconfigure compression equipment). The cost of operations would decrease marginally due to lower compression fuel requirements; however, most costs are fixed so saving would be minimal.

Transmission and distribution networks are subject to economic regulation under Part 4 of the Commerce Act 1986. This ensures that network owners earn a fair return of capital and return on capital for their investment. This sets the regulated revenue based on asset value. Pricing is based on throughput of gas and use of the gas network. If volumes of gas were to materially decrease, the

[4] Reservoir permeabilities for Maui range up to several Darcies. This is exceptional and most reservoirs permeabilities are measured in milli-Darcies (Kupe, McKee) or micro-Darcies (Mangahewa) New Zealand's Petroleum Basins - Part One (nzpam.govt.nz).
[6] GTAC Attachment D – Balancing and Line Pack SOP - 31 October 2018 GTAC - Gas Industry
[7] Contact Energy Media Announcement, 21 December 2022

regulated revenue would need to be spread across lower gas volumes and the unit cost of gas use would increase.

2.2.1 Key findings

The gas transmission and distribution pipelines can operate with lower throughput but there may be increased costs for users on a unit cost basis. There is limited flexibility in the gas pipelines to store gas for intraday uses. Current gas storage operations are also sustainable with lower throughput. However, as the Ahuroa gas storage field is a natural system, careful maintenance of pressure regimes and withdrawal/injection quantities is always necessary to maintain the deliverability of gas stored within the reservoir.

2.3 Demand

Demand for gas is largely driven by the petrochemicals sector, specifically Methanex which is likely to either decarbonise (using biogas or green hydrogen) or cease their operations in the coming decades if operations cannot be decarbonised. In either scenario, demand will drop dramatically, and the largest draw will be for electricity generation and co-generation, which currently consumes roughly a third of gas. While demand for electricity is expected to grow, it is also anticipated that an increasing share of generation will come from renewable sources.

Table 1 ***Gas usage by different sectors***

Gas usage[8]	
45%	Feedstock and Petrochemicals
30%	Electricity generation and co-generation*
15%	Plant and Industry
10%	SME consumption

Table 2 ***Potential future gas demand of Methanex Plants***

Methanex Plants – potential future demand	
Motunui 1	33 PJ
Motunui 2	33 PJ
Waitara	18 PJ
Total	84 PJ

Gas can be used as baseload electricity supply and peaking power supply. During periods of high electricity demand (i.e. mornings and evenings) or when renewable energy sources are unable to meet the electricity requirements, gas-fired power plants can be quickly dispatched to provide additional electricity supply. The role of gas as baseload has diminished due to economics with Taranaki Combined Cycle (TCC) and the Huntly Combined Cycle plants being the key plants for this duty. The existing gas generation fleet and capacity is shown below along with their retirement dates[9].

[8] About the Industry - Gas Industry

[9] These dates represent physical end of life forecasts, but actual retirement forecasts could differ due to economic or commercial factors

Table 3 ***Thermal generations plants with greater than 10 MW capacity and connected to the grid***[10]

Unit	Operator	Format	First product'n Year	Cap. MW	Thermal efficiency %	Retirement date
Huntly CCGT	Genesis	CCGT	2008	385	48.6%	2037*
Huntly OCGT	Genesis	OCGT	2004	48	34.2%	2046
SPS CCGT (TCC)	Contact	CCGT	1998	377	48.6%	2024
SPS OCGTs	Contact	OCGT	2010	210	40.4%	2035*
Te Rapa	Contact	Cogen	1999	44	30.8%	2023
Junction Rd	Nova	OCGTs	2020	100	n/a	2045
McKee OCGTs	Nova	OCGT	2013	100	34.0%	2038
Edgecumbe	Nova	Cogen	1996	10	31.3%	2033
Whareroa	Nova	Cogen	1996	68	38.7%	2038
Kapuni	Nova	Cogen	1998	25	38.7%	2040
Glenbrook	Alinta	Cogen	1997	112	n/a	2047
Total				**2,424**		

* May be extended by a mid-life refurbishment investment.

A gradual decline from other larger industrial users is also anticipated. This reflects a combination of rising economic activity, offset by higher energy efficiency and a trend toward lower emission fuel sources, such as bio-fuels. Absent any intervention, it is anticipated that once the wind-down begins it would complete in a short time-frame (i.e. the exit of each industrial user would make it more expensive and difficult for the other users to remain). For residential/commercial/agriculture users, decisions to switch energy source typically involve capital expenditure for appliances and modifications to premises; there are unlikely to be sudden shifts in the level of annual gas demand for these users. Demand will be affected by factors such as population growth, levels of economic activity and government policy (especially carbon-related policies).

2.3.1 Key findings

Current gas demand is 'lumpy', dominated by petrochemicals and power generation. These users underwrite long term contracts that support development of new reserves. Future demand is highly uncertain due to the range of options for decarbonising industries and the cost of these options. The uncertainty of demand may impact investment, resulting in diminished supply.

[10] EA, Enerlytica, MBIE 2020 Thermal generation stack update report (mbie.govt.nz)

3. Gas supply for dry year cover and peaking

We have examined scenarios for domestic supply of gas and imported LNG to support dry year cover. Dry year cover scenarios have been examined as shown in Table 4 below:

Table 4 ***Projected dry year cover statistics***[11]

	2035	2050	2065
Efficiency (LHV)	43%	43%	43%
Average generation (GWh/yr)	88	444	569
Average fuel use (TJ/yr)	739	3,713	4,764
Average fuel use (TJ/day)	2.02	10.17	13.05
Peak fuel use (TJ/yr)	6,838	13,884	12,304
Peaker capacity (MW)	168	831	996
Max delivery rate (TJ/day)	34	167	200
Capacity factor	6.0%	6.1%	6.5%
Swing (TJ/day)	**32**	**157**	**187**

Assumptions:

- Gas fired generation is located on the gas transmission line in existing locations; and
- Gas transmission system remains operational and fit for purpose[12].

3.1 Gas-fired generation

Thermal generators except for Kinleith, Glenbrook and Mangahewa are fuelled with one or more of the following three fuels; natural gas, coal, and diesel. Kinleith and Glenbrook are fuelled with by-product or waste streams, while Mangahewa is fuelled by raw wellstream gas instead of pipeline gas[13].

The typical specified design life of a thermal power plant equipment is 25 years operational life and 200,000 hours. Also, specified is the number of hot, warm, and cold starts. For each start, stop and trip event, an equivalent operating hours penalty is associated. However, the operating life of thermal power plants can extend beyond their original operational life through replacement and refurbishment of equipment. Thermal power plants provide one or more of the following three services; base, production, and peaking. Thermal OCGT power plants used for peaking will have greater starts, which reduces the operating hours and increased operations and maintenance (O&M) costs. The increased O&M cost is passed through to customers as a higher price offer during peak periods. Based on multiple factors such as net revenue vs. net costs and market competition the owner of the thermal plants may make an economic decision to either refurbish, place on standby, or decommission the plants before or at their design life. Older less efficient plants which require significant capital expenditure for emission related upgrades for regulatory compliance have been replaced with newer more efficient (heat rate <7,000 kJ/kWh – equivalent to approx. 51% thermal efficiency) and lower emissions units based on observations in USA and Europe[13].

As highlighted in Table 3 above, all the current fleet of thermal generations plants with greater than 10 MW capacity and connected to the grid are expected to be retired before 2050. This emphasizes the changing New Zealand electricity markets, fuel markets, and New Zealand's push for the national grid to be supplied with more renewable energy[13]. Therefore, new investments will be required to meet the 2065 Peaker capacity of 996 MW.

[11] Modelling results done for NZ Battery/ or Culy modelling
[12] Given the uncertainties noted above over gas supply and demand, the future operations of the gas transmission system are uncertain. However, as most gas fired power stations are either located in Taranaki or located on the Maui pipeline, the necessary infrastructure to maintain operations is a reduced scope of gas pipeline infrastructure.
[13] [2020 Thermal generation stack update report (mbie.govt.nz)]

Table 5 ***Potential future thermal generation plants***[13]

Proposed Plant	Capacity (MW)	Fuel Type	Location	Ownership
Waikato Power Plant (WPP)	360	Natural Gas	Otorohanga	Todd Generation
Huntly Repowering	400	Natural Gas	Waikato	Genesis Energy
Cogen 1	50	Natural Gas / Biogas	TBC	TBC
Hydrogen 1	500	Hydrogen	TBC	TBC

Table 5 above lists the potential future thermal generation plants. Some of the proposed thermal plants will be used to provide peaking service, while some of these in a dry year will be in a baseload role. As new generation capacity will only be used intermittently, investors may be reluctant to invest without guaranteed return. As a wide range of complex technical and commercial factors need to be considered before deciding to build a new generating plant. Also, the intermittent usage of generation equipment has risks in terms of operations, maintenance, and skills retention[13].

3.2 Domestic gas

Projections of 2P reserves production are shown in the table and figure below. This is proven and probable (2P) reserves that are developed and economic. While these will require ongoing investment to produce, they are known accumulation and the production profiles have a 50% probability of success. Additional to 2P reserves are contingent resources, which are known accumulations that are not technically or economically feasible to produce. These are located in existing permits and could be brought into production in the right economic conditions. The profiles shown below are therefore conservative.

Table 6 ***New Zealand gas production projection on a 2P basis***[14]

	2035	2050	2065
Gas Supply (PJ)	51.40	6.05	-

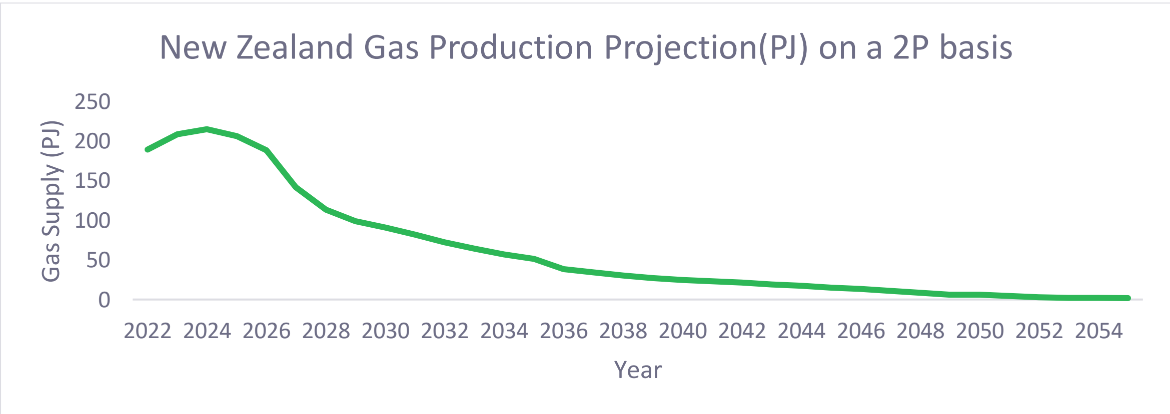


Figure 1: ***New Zealand's Gas Production Projection (PJ) on a 2P basis***

3.3 Supply for dry year cover

3.3.1 Supply assessment

Table 4 highlights that the average annual fuel supply required is 3,713 TJ/yr in 2050 and 4,764 TJ/yr in 2065 for electricity generation and co-generation. Therefore, the average daily fuel supply required is 10.17 TJ/day in 2050 and 13.05 TJ/day in 2065. However, to maintain the gas supply an ongoing investment of $200 million a year is required across Taranaki fields at current levels of production and configuration of production facilities[15]. Based on current projections as shown in Table 6, 6,050 TJ/yr of domestic gas supply will be produced in 2050 on a 2P basis. Finally, skills

[14] https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/petroleum-reserves.xlsx
[15] Gas-Industry-Co-Gas-Market-Settings-Investigation.pdf (gasindustry.co.nz)

and capability will be required to maintain the industry, and these may diminish as the gas supply reduces, especially given the current ageing workforce[16].

3.3.2 Gas availability for electricity supply

As highlighted in Section 2 the future demand for gas is in a downward trend till 2035 and is expected to follow the trend till 2050. In 2050, 3,713 TJ/yr will be required for electricity generation and co-generation[11]. Based on the projected supply of gas in 2050 of 6,054 TJ/yr on a 2P basis, it is estimated that there will be enough gas available to cover the annual demand[14] (assuming gas is not used for anything else). Therefore in 2050, on average the projected daily supply of gas of 16.59 TJ/day will be enough to cover the average daily demand for electricity generation and co-generation of 10.17 TJ/day, but not the swing of 156.80 TJ/day[11]. Therefore, the energy needs to be stored over a number of months and withdrawn over a number of days to meet electricity load.

3.3.3 Cost assessment

A high-level estimate for a long-term delivered gas price is $13.50/GJ (real terms, excluding carbon)[17]. This is based on the current market state and large users underwriting demand and is set against the price of LNG import to set a ceiling price on the commodity (i.e. if gas prices were to rise above this level LNG imports would be undertaken and domestic gas production would be limited). Moreover, the price is likely to increase in a smaller market: as highlighted in Table 6 the supply of gas decreases on a 2P basis, therefore the unit price of gas is expected to increase to cover all the fixed costs of the fields and delivery infrastructure across the smaller amount of supply[18]. Recent gas sensitivity modelling by Business Energy Council tested the scenario that if Methanex leaves New Zealand in the future, as a result of which it assumed gas prices could rise to $35.00/GJ from less than $10.00/GJ today. Moreover, the cost of storage of $4.00/GJ would need to be added if natural gas is required by the electricity sector for peaks and dry years[19].

3.3.4 Key findings

On an average basis gas supply is likely to be sufficient but will rely on the necessary investment and skills/capabilities being maintained. However, as demand is not constant, gas would likely need to be stored in order to meet periods of higher demand than the average supply rate. The size and withdrawal capacity of this storage will be key to meeting demand.

3.4 Infrastructure

We have considered two options for storing gas, underground storage and above ground LNG storage.

3.4.1 Underground gas storage

Current working storage volume at Ahuroa gas storage facility is between 6-8 PJ and withdrawal capacity of 65 TJ/day[7]. While expansion of Ahuroa has previously been considered to 100 TJ/day this may not be feasible given the updated information on the reservoir relating to the reduction in operational storage volume. Other potential underground gas storage facilities include Tariki which is being assessed. Current data indicates that Tariki gas storage facility could store up to 15 PJ of gas, with injection and production rate of 25 TJ/day from a single well, and up to 75 TJ/day from 3 wells[20]. To meet 2050 dry year peaking needs around 14 PJ of gas may be required. If this is supplied over a notional 3-month period, 1.5 PJ of gas can be from field production, while around 5.9 PJ can be supplied from Ahuroa gas storage facility based on its withdrawal capacity. As a result, an additional storage gas facility will be required with a storage capacity of 6.7 PJ. The additional storage should have a minimum withdrawal capacity of 74 TJ/day. If Ahuroa is able to be expanded to 100 TJ/day withdrawal capacity, this requirement would change. However, expanding the

[16] 237 (energyresources.org.nz)
[17] New Zealand Battery Project Indicative Business Case v1.10 and Appendices – February 2023 (mbie.govt.nz)
[18] Gas-Infrastructure-Future-Working-Group-Submission-on-Gas-DPP3-draft-decision-14-March-2022.pdf (comcom.govt.nz)
[19] Early action, open options key to emissions cuts – BEC | Energy News
[20] New Zealand Energy Corp Announces 2022 Quarter 3 Results - Bloomberg

withdrawal capacity at Ahuroa gas storage facility is not without risk and would need to be studied in detail to ensure this capacity is feasible given the updated state of reservoir understanding.

The creation of a new underground storage facility to provide additional capacity is a significant investment involving three main development phases:

- Seismic data gathering and analysis
- Front end engineering and design, leading to a final investment decision
- Drilling and construction

Ahuroa gas storage facility was opened in 2011, and the development cost was $177 million[13]. As a natural system, the ability of a reservoir to store gas for withdrawal is always uncertain. Careful management of the injection and withdrawal rate will be required to maintain deliverability.

3.4.2 Above-ground LNG storage tank

Methane (natural gas) changes from a gaseous state to liquid state when it is cooled to -162° C. The liquid state is 1/600th of its original volume at standard pressure and temperature, which improves the ability to ship it safely and efficiently on a commercial basis[21]. Currently, no above-ground LNG storage tank exists within the New Zealand gas market. As well as the storage facility itself, the infrastructure required for liquefaction, regasification, and pipework to connect the facility to the gas network and/or downstream assets would need to be commissioned. The benefit of an LNG storage tank over underground gas storage is that the facility could be more specifically sized to meet market needs and provide more flexible rates of comparable "injection" (in this case, liquefaction) and "withdrawal" (regasification). The drawback is that LNG storage tank are expensive to install and can consume significant amounts of energy themselves in the liquefaction and regasification process, with energy losses typically of between 2-5% of total gas stream inputs. As this is an engineered system, the deliverability of gas is more reliable than reservoir storage but has a greater cost and surface footprint. While LNG storage tank are designed to maintain the correct temperature to keep the gas liquid, it is inevitable that some methane (around 0.05% each day) will 'boil-off' and become a gas. This gas will need to be siphoned off for use or vented to maintain safe storage pressures[22]. Therefore, LNG is not able to be stored indefinitely, and this is a particular problem as we are trying to potentially store gas for several years.

3.4.3 Key findings

Additional storage with sufficient withdrawal capacity will be required for domestic supply to meet dry year and peaking needs due to the need to rapidly ramp up or down to meet variations in electricity demand. While underground storage may be more economic, subsurface risks and the need to carefully maintain reservoir pressures make intermittent usage more uncertain.

3.5 Summary of key findings

- **Reserves/resources are likely to be sufficient on an aggregate basis but deliverability to peak levels, and swing supply will be difficult and potentially costly.**
- **Reservoirs are natural systems that are suited to steady state production – large swings in production risks damage to the reservoir and destruction of value.**
- **Significant investment is required for the gas industry to maintain production and this investment has been traditionally supported by petrochemical users. Continued operation by this sector is uncertain – especially if gas costs increase.**
- **Lower throughput in the transmission system will increase infrastructure costs.**
- **Further investment would be required for gas storage (and potentially regasification in the case of LNG storage) to meet peaking need.**
- **The skills required to operate gas fields, gas pipelines and attendant infrastructure are highly specialised. These are in short supply and may be difficult to maintain with a declining industry and ageing workforce.**

[21] Learn about LNG: What is Liquefied Natural Gas? — Chevron
[22] Microsoft PowerPoint - What is Boil-off.ppt (unece.org)

4. International Imported LNG as dry year cover

4.1 Supply

The international LNG market is liquid and of sufficient volume (372.3 MT in 2021) that NZ would be able to source gas from this market for the foreseeable future. The 2021 annual market volume represents 5% growth on 2020 as many countries rebound from the economic impact of the COVID-19 pandemic. Key suppliers are Australia, Qatar, USA and Russia, exporting 83, 77, 67 and 30 MT per annum respectively in 2021.[23]

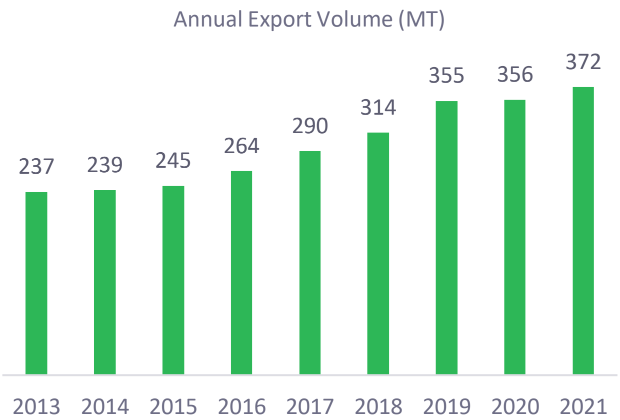


Figure 2: ***Annual LNG Export volumes***[19]

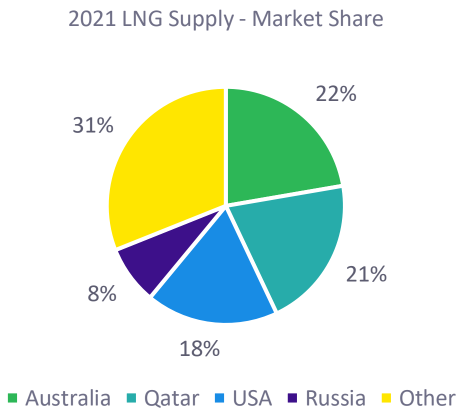


Figure 3: ***LNG Supply market share***

It is anticipated that the global LNG market will see a number of new projects in mid-2025/2026.These supply additions comprise 64 million metric tons of annual liquefaction capacity boosting the global capacity by roughly 14% in a single year[24] compared to 6% of annual growth over the last 8 years. Export Growth has been largely led by USA with an increase in 24 MT of liquefied natural gas in 2021.

This modest supply growth and consistent demand is likely to have little effect on price so global LNG prices may remain elevated for several years. High prices may put sustained downward pressure on demand growth, particularly among price-sensitive emerging markets that were widely expected to be the primary drivers of global LNG demand[10]. However, this needs to be balanced against demand for LNG in Europe as they looks to shift from Russian pipeline gas. Furthermore, the shift away from fossil fuels globally will change market dynamics and investment attractiveness in the longer term.

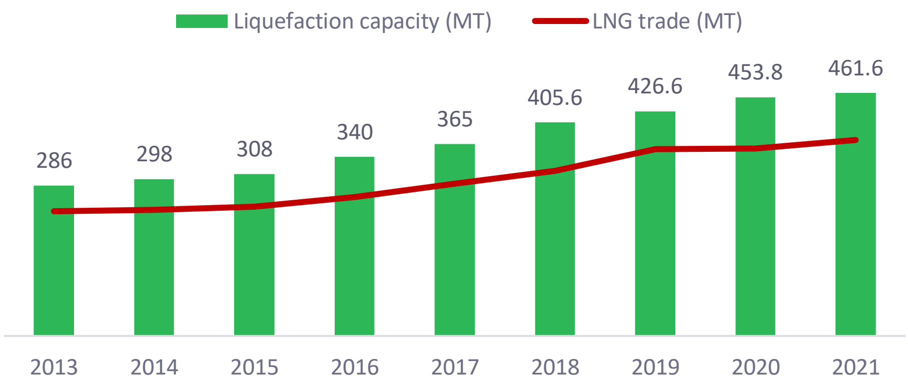


Figure 4: ***Annual Global Liquefaction Capacity vs. LNG Trade Volumes***

[23] [Global LNG Trade - (giignl.org)]
[24] [Global LNG Outlook 2023-27 | IEEFA]

The annual required import volume for NZ dry year cover of ~6.7 PJ would equate to ~2 cargoes of LNG per year at 4 PJ per cargo – noting that it would be unlikely that partial cargo deliveries would be commercially feasible. This is 0.043% of the global market (15,587.5 PJ 2021).[10] To secure supply the following is required:

- Long-term contract
- Regular shipments (cannot simply be bought quickly to address a shortage)

Long-term contracts represent the greatest share of contracts signed, but their time duration continues to be reduced over time. Longer term contracts are signed for new projects to guarantee project economics, while expiring contacts are replaced by shorter ones.

An increasing number of 10-year contracts is observed, pushed by trading companies and portfolio players which continue to play a growing role in new contracts. While LNG has traditionally been traded on long term sale and purchase agreements, but a spot market has emerged for cargoes.

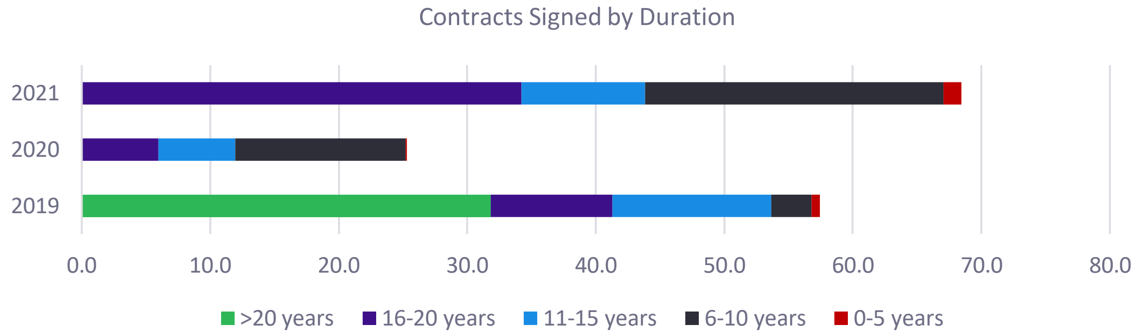


*Figure 5: **Global LNG Import Contracts by Duration***

For the last 20 years prices for LNG have hovered around $5-$15/GJ, however recent events have caused a spike in the price with expectations that it will exceed $20/GJ. For the 5-8 PJ of dry year cover gas estimated above, at $20/GJ the total annual landed costs would be $100 - $160m prior to factoring in the cost of regasification (see next section). This is double the cost of $50 - $80m at current domestic gas prices of c. $10/GJ.

The Russia-Ukraine conflict has placed upward pressure on LNG prices in the past few years. Russia accounts for approximately 17% of global natural gas production. European gas markets, which have traditionally relied on Russian gas supply, have been forced to quickly search for alternative supply sources, boosting demand for other markets such as the Australian LNG exports. In March 2022, the United States and the United Kingdom also announced restrictions on importing Russian oil and gas relying on the same alternate markets for gas supply.

Continued strong demand for LNG in export markets is expected to place upward pressure on prices over the following years and forecasts predict the average export price of liquefied natural gas to rise by 30.3% in 2022-23, reaching $20.93/GJ.[25]

[25] F6211 Export price of liquefied natural gas - MyIBISWorld

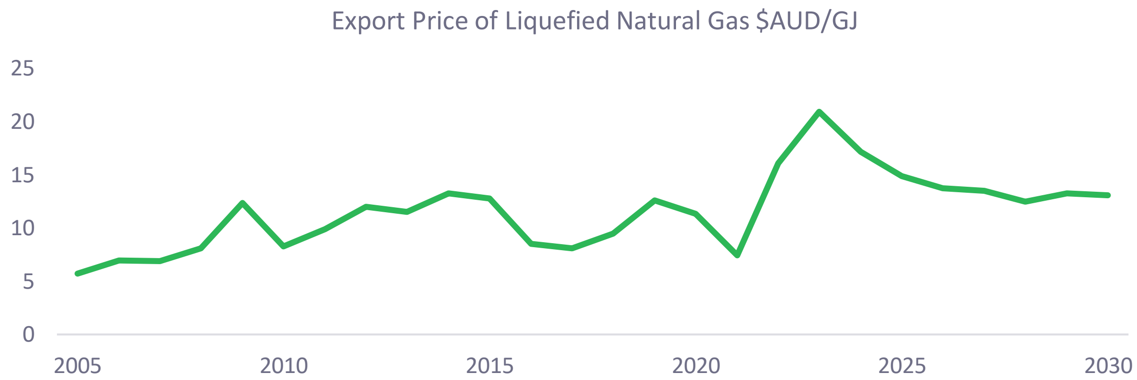


Figure 6: ***Australian LNG Export Price***

4.1.1 Key findings

New Zealand's entry into the international LNG market would be too small to have any significant effect on both the supply of LNG and the global price. The price to import LNG is much higher than NZ domestic gas pricing and although supply growth is likely to see an increase over the coming years, this is not likely to be of a large enough scale to put noticeable downwards pressure on global prices. Cargo sizing will also make it difficult for a single New Zealand buyer to purchase LNG internationally and large users (such as Methanex and Ballance) are unlikely to be willing to pay for LNG.

4.2 Infrastructure

We have considered two infrastructure options for importing LNG into New Zealand, Floating Storage and Regasification Unit (FSRU) and Floating Storage Unit (FSU).

4.2.1 Floating Storage and Regasification Unit (FSRU)

Given that New Zealand is currently a solely domestic gas market, significant investment would be required to facilitate the importing of LNG. This would include investment in the following infrastructure:

- Floating storage and regasification units (FSRU)
- Pipelines to transmit the gas onshore

Generally, FSRUs are leased as they are able to be redeployed at the end of the lease. FSRUs generally hold around one cargo of gas (4 PJ).
The rate at which the gas is transferred onshore is dependent on:

- the capacity of the onshore transmission pipelines
- the need for the gas to be either stored or used once transported onshore

Table 7 ***New Zealand Pipeline Capacity and Transfer Time via. Location***

Onshore Transfer	Pipeline/Injection Capacity (TJ/day)	Transfer Time (days)
Taranaki	500	8
Marsden Point	20	200
Ahuroa	65	61

While these timeframes are not an issue if 4-7 PJ of gas is required per annum, at higher volumes of 20 PJ, 5 cargoes will be required per year. In this scenario, the time to discharge the FSRU may be too long to empty the FSRU between cargoes. There are 2 potential solutions to this issue:

- An import terminal is located in Taranaki and there is no other domestic production. An FSRU could provide the required 260 TJ/day dry supply for 16 days between and ships could arrive fortnightly to cover seasonal needs.

- A more likely scenario is that it would need to be complemented by domestic storage to manage offtake between cargoes.

It should be noted that the lead time on sourcing cargoes is 4-6 weeks, so commercial operations of the facility would need to be refined to ensure availability was not impacted by cargo lead times.

The utilisation of the plant would be low: 4-7% in the 4-7 PJ/annum scenario and 20-25% in a 20 PJ/annum scenario. The low utilisation will add to the unit gas price. High-level cost estimates provided by WSP suggest lifetime costs in the order of $2 billion (real, NPV) for port development, purchases and the operation of a floating storage and regasification unit.[26]

Table 8 ***FSRU-Import Facility Initial and Ongoing Costs***

Capital Cost (per FSRU)	Capex ($000)	Opex ($000)/yr
Port	350,000	$26,000
FSRU	650,000	$64,000
Compressor	90,000	
Total	1,090,000	$90,000

4.2.2 Floating Storage Unit (FSU)

Another option which is applicable to the Marsden Point location only is to use an FSU and the regasification process will occur in either a Floating Regasification Unit (FRU) or on land in the offshore plant. This, however, comes with a whole new set of costs and regulations which need to be considered before making such an investment.

Through this method and adding compression increases the handling beyond the maximum flow of the pipe. Adjusting for this can be estimated to cost around $20m which is to be combined with standard FSRU setup costs for the necessary storage and regasification tanks required in completing this process.

Supplementing the pipeline to cater for the extra flow can be achieved by transporting the LNG on the road to regasification tanks where it can be fed back into the network. This transport in itself would involve extra levels of regulatory compliance and further complexity due to their being no potential regasification sites within ~100km of Marsden Point. Due to this additional compliance, cost and risk profile, using a FRSU is the most suitable option.

4.2.3 Key findings

Due to New Zealand's current reliance on domestic gas supply, importing LNG from overseas would require significant investment in the regasification, transport and storage of the gas. The economics of the project are highly dependent on the location of the import terminal, the number of cargoes imported per year and domestic gas production during the offloading period. Transfer time is highly variable based on the location of the import terminal ranging from 8 days to 200 days. Importing a higher volume of gas also creates a further issue with this timing and begins to clash with domestic gas production due to longer offloading periods.

The investment in importing LNG also requires significant CAPEX as well as ongoing operational costs. The setup cost of just one FSRU is $1.09b in initial cost, as well as an additional $100k per year to keep operational which WSP forecasts a lifetime cost of $2b per FSRU (additional $20m for the pipeline replacement in the case of using an FSU at the Marsden Point location).

4.3 Summary of key findings

NZ would be able to source sufficient LNG to meet the dry year and peaking challenge on an aggregate basis to the large global market. The cost of imported LNG would likely be higher than

[26] WSP Report Modelling Assumptions for fossil-fuelled peaker generation

domestic gas and exposure to the export market may link prices and has the potential to increase the price of domestic gas. If gas prices were to rise to this level, the cost of using gas for security of supply in the electricity system in 2050 could more than double.
While the aggregate demand will be able to be met, the ability of LNG import to meet daily electricity demand will depend on the location of the terminal/adjacent pipeline capacity, ongoing domestic production and the quantity of gas being imported each year not to disrupt domestic production. It is therefore likely that additional storage infrastructure will be required to support an LNG import facility.

The infrastructure required for import is significant, and while FSRUs can be chartered, there will be a need for sufficient throughput in the facility to reduce costs on a unit basis. LNG facility operations require high levels of skill and capability issues may arise due to the ageing domestic gas workforce. The cost to setup up this infrastructure is also very large with considerable ongoing expenses to keep these facilities under operation. Financing these costs is likely to become more challenging over time, as well as the investment required for upskilling and training of personnel.

5. Conclusion

This work has shown that, while domestic gas and/or imported LNG could provide enough gas on an aggregate basis to support a fossil peaker scenario, the need to provide 'swing' means that gas storage and potentially other infrastructure will be required to support peak daily demand. However, the ability of the domestic gas market to meet demand and the ability and willingness to meet and finance the significant investment required for the infrastructure necessary to support LNG imports would need to be investigated further as part of the NZ Battery detailed business case (DBC).

Further, this work has identified a number of uncertainties in our investigation that are material to obtaining a reasonable assessment of a fossil peaker scenario, including demand for gas to support investment in production, demand for gas to support transmission infrastructure, storage availability and investment in withdrawal capacity, LNG import terminal location and scenario and skills and capability availability. The NZ Gas Transition Plan (once finalised) will provide some guiderails on the demand and supply scenarios. Aligning with this work, and the work in the National Energy Strategy, will be important to providing a coherent view of gas supply and demand on which to base any fossil peaker scenario to be included in the NZ Battery DBC.

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