Possible commercialisation options for new gas discoveries
February 2015
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Executive summary

Background and scope

In October 2014, Gas Industry Co published an update to the New Zealand gas supply / demand study which explored the factors that were likely to influence gas outcomes for New Zealand, and considered possible futures for the New Zealand gas sector.

In analysing the demand-side of the equation it only focussed on existing sources of demand.

However, with investment in upstream investment continuing, there is the potential for significant new gas discoveries – the scale of which may exceed the ability of existing sources of demand to consume.

Accordingly, this report considers what new opportunities may exist to commercialise any significant new gas finds beyond the existing sources of demand. In particular, it considers the issues and opportunities for:

- Liquefied Natural Gas (LNG)
- New petrochemical production
- Gas as a transport fuel
- New gas-fired power generation; and
- Increased industrial, commercial and residential demand

The analyses in this report focus on the medium to long-term options for commercialising gas. The feasibility of many of the options depends critically on external factors such as world energy prices and currency exchange rates, all of which are subject to volatility. Predicting these factors years in advance is obviously difficult to do with any amount of certainty. This study uses the following long-term central assumptions, which were chosen because they represent a moderate view of the future:

- US$75/bbl oil price;
- NZ$6/GJ domestic gas price;
- 0.70 US$/NZ$ exchange rate; and
- NZ$25/tCO2e carbon price.

Liquefied Natural Gas (LNG)

Selling LNG into Asia potentially represents one of the most valuable opportunities for any gas found in New Zealand. After taking into account liquefaction and shipping costs, the net-backs to gas producers are estimated to be between NZ$3.5-11/GJ.

This is based on estimated long-term Asian LNG prices of between US$11-14/mmBtu (approx. NZ$15-20/GJ), which are likely to be driven by the cost and extent of new LNG developments in the US (particularly the Gulf Coast), and the potential (wide) range of possible costs for developing a liquefaction facility.

1 Long Term Gas Supply and Demand Scenarios, September 2014. This report can be found here: http://gasindustry.co.nz/work-programmes/gas-transmission-investment-programme/supply-and-demand/long-term-gas-supply-and-demand-scenarios/
Compared with US Gulf Coast developments, New Zealand enjoys an advantage in terms of materially lower shipping costs to Asia. Offsetting this advantage are likely higher costs of developing liquefaction facilities due to New Zealand’s remote location, and greenfield status. However, recent developments in floating liquefaction facilities could significantly reduce any such cost disadvantage.

Some countries with gas reserves that are potentially of LNG-scale have attempted to maximise the perceived local economic benefit through requiring developers to either:

- Develop the liquefaction facilities onshore, rather than as floating developments, in order to boost the local economy.
- Require some of the gas to be ‘reserved’ for in-country consumption at a price which is lower than the world LNG price.

Some commentators have raised the idea of a similar stance being taken for potential New Zealand developments. However, overseas, such policies often appear to have been self-defeating in that the extra costs they impose (either in the form of higher project costs, or in the form of an extra tax on producers\(^2\)) have discouraged investors from developing otherwise profitable gas fields – with the result that the local economy has not benefited at all.

In addition, the majority of such reserved gas for local consumption would likely be ‘exported’ in the form of petrochemicals or milk powder, resulting in a significantly lower realised value for the gas compared with exporting it as LNG, and thereby lowering New Zealand’s potential export earnings. Viewed from this perspective, a reservations policy does not seem to make sense for New Zealand.\(^3\)

There appear to be economies of scale for LNG production, meaning that it would probably only be cost-effective for fields which are large on a New Zealand scale – approximately 3-4,000 PJ in size (i.e. only slightly smaller than the Maui field).

If gas is discovered in New Zealand which is smaller in scale than the minimum required for LNG, there are a number of factors which will determine whether it is economic to develop, particularly:

- Whether the gas is ‘associated’ with significant oil production – which would substantially pay for the field’s development costs;
- Whether the field is distant from land – which will dictate whether it would be economic to invest in the pipeline and processing infrastructure to bring any gas associated with oil to shore, rather than re-inject it back into the reservoir.
- Whether the field is close to existing offshore pipelines and/or onshore gas processing infrastructure which could be used for the field’s development. This last factor means that the minimum scale for new gas field development is likely to be smaller for Taranaki discoveries, than it is for discoveries elsewhere in New Zealand.

**New petrochemical developments**

This study has focussed on petrochemical options for use of methane and ethane. This is because the heavier hydrocarbons (propane, butane and above) are readily extracted as liquids and sold domestically or overseas and therefore do not face any particular commercialisation barriers.

\(^2\) The difference between the LNG export price – the price the producer could have gotten for a unit of gas, absent the reservation policy – and the reserve price effectively acts as a tax on producers

\(^3\) In the case of using gas for dairy production, it should additionally be appreciated that any sub-market price gas consumed would be displacing domestic fuel sources – namely coal or biomass – with consequent negative impacts on these domestic industries.
Petrochemical options using extracted ethane (i.e. the development of ethylene as a primary chemical feedstock and/or subsequent secondary feedstocks) are not deemed to be commercially viable in New Zealand because:

- Economic scale is unlikely to be achieved, given the likely size of any gas discovery and the relatively small volumes of ethane in natural gas.
- The Marsden refinery is distant from current gas processing facilities, and ethylene production is generally co-located in refineries to take advantage of infrastructure synergies.

For methane (and the ethane left in the gas stream), the three main petrochemical options are Methanol; Ammonia; or Urea.

All three options are mature technologies and can be readily sold on well-developed international markets. Generally, it would be expected that the $/GJ gas netback value that could be achieved from developing any of these options would be similar internationally over the long-term. However, at any one moment in time it is possible that one of these commodities would be in shorter supply relative to the others, favouring investment in that option. Currently none of the three commodities seems to be excessively short or long in supply internationally.

The price at which gas could be sold to a petrochemical producer would likely be based on the price at which the producer could purchase gas from the next most attractive international location – factored by any differentials in international shipping costs to get the petrochemical product to the end market. For the next decade or so, North American gas prices are likely to be the relevant benchmark in this context. Based on the current Henry Hub forward curve, this gives a price of approximately NZ$5.5/GJ. However, this could be an upper limit, as petrochemical companies may apply a discount for purchases from a relatively small isolated gas market such as New Zealand to reflect the increased reserves risk associated with relying on a relatively small number of gas fields. It is not clear the extent to which any such discount would result in a material reduction in price for New Zealand gas – particularly as it is likely to be field-specific. However statements from overseas petrochemical producers (albeit in a general international, rather than New Zealand-specific, context) suggest that it could be material in some situations.

In the specific case of New Zealand it appears that all options could be economic, and petrochemical producers have expressed a willingness to consider increasing production capacity if significant new gas is found.

A new urea facility may be a particularly attractive option, because it would enjoy a relative advantage compared with methanol or ammonia in terms of avoided international shipping costs. This is because there is a significant amount of domestic urea consumption, and a significant urea demand nearby in Australia. Conversely, the main markets for New Zealand methanol or ammonia would be Asia. The scale of this price advantage for urea is estimated to be between NZ$0.5-1.5/GJ.

Scale issues may also have a bearing on the most appropriate new petrochemical option for New Zealand. Urea may possibly support smaller scale developments (10 to 20 PJ/year), whereas

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4 This is because if superior gas netback returns could be achieved from one commodity, it is likely there would be sustained investment in production capacity for that commodity until the supply / demand balance shifted to a situation of relative over-supply – reducing the gas netbacks. Over time this should result in similar gas netbacks, although the period of the cycles may be some years given the capital intensive nature of the industries.

5 This assumes a Canadian West Coast location for the alternative petrochemical producer given the very similar shipping costs from Canada to Asia as from New Zealand. In doing so it factors in the pipeline costs in getting the gas to the Canadian West Coast.
methanol production may be more appropriate for larger quantities of gas. However, all options appear to be reasonably scalable.

**Gas for transport**

Around the world there have been significant developments in using gas as a transport fuel to displace oil-based fuels. The principal driver of these developments has been economic, given significant differentials (at least until recently) between oil and gas prices in many parts of the world.

There has not been a strong greenhouse environmental driver behind such initiatives – noting that the CO₂ emissions from natural gas-based fuels are generally similar (and in some cases greater) than oil-based fuels. However reducing exhaust emissions that affect human health has been a key driver in some places, particularly China, where petrol and diesel vehicles are contributing to urban smog. Similarly, the drive for switching from fuel oil to natural gas-based fuels for European shipping is principally around reducing sulphur emissions which cause acid rain.

There are two broad options for using natural gas as a vehicle fuel:

- Fuelling a vehicle *directly* with natural gas, with the gas stored in the vehicle in either: liquid form (i.e. **LNG**); or compressed form (i.e. **CNG**). With this option, the LNG or CNG would be produced using ‘micro’ production facilities at locations around the country using pipeline gas, and vehicles would then be fuelled at these production bases.

- Fuelling a vehicle with a liquid fuel that has been *synthesised* from natural gas, particularly: methanol (either alone, or blended with other traditional fuels); dimethyl ether (DME); or synthetic petrol or diesel (known collectively as ‘synfuels’). These options use ‘macro’ production facilities with the fuel subsequently distributed to service stations (or potentially bases for return-to-base options)

For the purposes of considering the potential for gas as a transport fuel it is useful to distinguish between the light transport fleet (i.e. cars and light commercial vans) and the heavy fleet (i.e. trucks and buses). This distinction is because heavy vehicles require more power (which means some fuels are not suitable), and the vehicles often tend to be more specialised and operate within tightly-defined routes – which opens up opportunities for dedicated fuelling infrastructure.

Figure 1 shows the estimated ‘at the pump’ cost of different natural gas and petroleum based fuels for light vehicles.
Although CNG-fuelled vehicles may appear to offer the prospect of significantly cheaper fuel at the pump than petrol or diesel, it is considered that it is unlikely to be an attractive prospect for commercialising New Zealand gas. This is because CNG-fuelled vehicles need modified engines which, apart from impacting on the economics, require specialised re-fuelling infrastructure to be installed at service stations. Unless, and until, such refuelling infrastructure is widespread throughout New Zealand, drivers of CNG-fuelled vehicles will suffer ‘range anxiety’ in terms of whether they will be able to drive their vehicles wherever they want and be able to refill with fuel. This range anxiety creates a Catch-22 situation where drivers are unwilling to purchase CNG-vehicles until there is significant refuelling infrastructure, but service station companies will be unwilling to invest in such infrastructure unless there is a reasonable likelihood of significant numbers of drivers.

Further, CNG-fuelled light vehicles are likely to be overtaken in terms of offering significantly cheaper fuel by electric vehicles; additionally, plug-in hybrid electric vehicles do not suffer from the same range anxiety issues as CNG vehicles.

Synthetic petrol or diesel does not appear prospective due to the fact that the high capital cost of such a facility requires a significant oil to natural gas price differential in order to be economic. Although such a facility may work with > US$100/bbl oil prices and NZ$6/GJ gas, it will not be economic with current oil prices (i.e. ≈ US$50/bbl today, rising to ≈ US$65/bbl in five years’ time),

Although the graph indicates that the cheapest fuel price option is electric vehicles followed by CNG, what this graph does not show is that at the moment such vehicles come at a capital cost premium which adversely affects the total economics for vehicle users. Further, for CNG the delivered fuel price assumes that the refuelling infrastructure cost is recovered by a sufficiently large number of vehicles to achieve the necessary economies of scale. As set out above, the Catch-22 nature of this issue may prevent such outcomes from occurring.

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and/or the higher gas prices which were seen in the mid 2000’s and which could potentially emerge again in subsequent decades if there is insufficient upstream exploration success.

Pure methanol-fuelled vehicles suffer the same drawbacks as for CNG: the need for engine modification and range anxiety. However, blending methanol (up to 15%) in petrol, which does not require modifications to engines, would appear to be a significant value opportunity for New Zealand – saving up to $150m per year in avoided international oil purchases and improving fuel security. However:

- This option faces a significant barrier in terms of vehicle manufacturers not including use of methanol blends within their vehicle warranties – despite international evidence suggesting that methanol blends should cause no issues for most vehicles manufactured after 1990.

- Using methanol as a transport fuel would not result in any new gas being consumed in New Zealand as the methanol would come from one of the three existing methanol production trains. As such it would not facilitate the commercialisation of new gas fields.

Figure 2 shows the estimated ‘at the pump’ cost of different natural gas and petroleum based fuels for heavy vehicles.

Figure 2: Estimated cost per GJ for existing and potential fuel options for heavy duty applications (excluding taxes)

Some heavy fleet ‘return-to-base’ vehicles (e.g. buses, rubbish trucks, dairy tankers) using gas-based fuels such as CNG, LNG and DME appear prospective, and offer the potential for significantly lower fuel prices.

However, although they may be economic in their own right, the quantity of gas associated with such options is relatively small – of the order of 3-5 PJ/yr – and thus unlikely to offer material ability in their own right to commercialise a significant new gas find. Further, the technology-taker nature of New Zealand transport, and the fact that vehicle manufacturers for heavy trucks have yet to settle
upon a preferred option between LNG and DME, means there is potential technology stranding risk from investing in a technology which subsequently proves not to be adopted widely worldwide.

The need to have widespread specialised refuelling infrastructure to overcome range anxiety issues is likely to be a significant barrier to expanding such options for non-return-to-base vehicles. This will also be an issue for methanol-fuelled vehicles. Unlike places such as the US West Coast, it seems that New Zealand does not have the density of freight vehicles along major transport corridors to support such developments.

New power generation development

The power generation sector has historically played an important role in commercialising new gas discoveries in New Zealand and around the world, with combined cycle gas turbines (CCGTs) being the most cost-effective baseload option.

The price which a possible future CCGT could pay for gas will be capped by the cost of alternative baseload generation options – which for New Zealand is currently geothermal or wind generation – factored by future CO₂ costs.

The high degree of uncertainty over future CO₂ prices translates into a high degree of uncertainty over the future price that a CCGT could afford to pay for gas in order to be competitive. A reasonable central estimate would appear to be NZ$4-5/GJ, but with significant CO₂-uncertainty-driven variation either side. Further, as with sales to petrochemical producers, if a power generator were to take on field reserves risk, this would likely translate into a further discount on their willingness to pay for gas.

Conversely, open-cycle gas turbines (OCGTs) continue to be competitive against all other forms of new generator to meet any growth in ‘peaking’ demand (i.e. for relatively short periods during morning and evening peaks, particularly over winter time). However, the PJ-equivalent gas demand for such peaking generation is relatively small – approximately 1-2 PJ/yr growth.

Unlike new petrochemical options, for whom the international market is vast compared to the scale of New Zealand gas resources, new gas-fired power generation is heavily constrained by the extent of growth in electricity demand. Over recent years New Zealand electricity demand has contracted due to a variety of factors, including the Global Financial Crisis (GFC), a decline in some major industrial demand, and energy efficiency developments. Even if non-heavy-industrial electricity demand were to return to pre-GFC growth rates, the extent of annual baseload demand growth would only be equal to 20% of the output of a new 350 MW CCGT. This will further hinder the competitiveness of CCGTs against geothermal and wind (which can be more readily built in smaller increments), and means that gas-fired power generation would not, on its own, be as effective as a new petrochemical development in rapidly providing a significant additional source of demand to commercialise a significant new gas discovery.

Direct use of gas for energy

There is considered to be little opportunity to ‘create’ significant new demand for gas through the development of new gas-consuming industries (other than the petrochemical industries discussed earlier). This is because gas is a relatively small factor input for the vast majority of non-petrochemical industries. Therefore gas price will have limited influence on an industry’s expansion or location decisions. Accordingly, the main opportunity to significantly grow the direct use of gas in response to lower gas prices is through fuel switching.

If gas is found in the South Island, and it is not of a scale to justify LNG development, by far the largest fuel switching opportunity relates to displacing existing coal-fired industrial process heat. The price at which such gas could be sold will depend on the cost of alternatives (namely South Island coal and biomass), factored by CO₂ prices and the cost of developing new pipelines. This
suggests a price of between NZ$4-6/GJ, assuming the $/GJ costs of pipelines are the same as current North Island pipeline charges.\(^7\)

However, the scale of potential demand is unlikely to be very large (= 20 PJ/yr), and will probably take a long time to build up given that it will be strongly influenced by the capital replacement cycle of boilers. This means that direct use of gas in the South Island would not, on its own, be as effective as a new petrochemical development in providing a significant additional source of demand to commercialise a significant new gas discovery.

In the North Island it is considered that most of the significant opportunities to switch to gas for process heat have already been taken up, and what opportunities do exist (particularly for switching from coal to gas for process heat) are of a relatively limited scale.

**Summary**

Figure 3 below presents the estimated range of netbacks which could be achieved for selling gas to new sources of demand for New Zealand.

*Figure 3: Estimated range of netbacks for new gas commercialisation options in New Zealand*

As can be seen, for each option there is generally a considerable range of possible prices reflecting inherent uncertainty over factors such as:

- the future product price
- the future price of alternatives (e.g. coal, oil, biomass, or renewable electricity, overseas sources of gas)

\(^7\) It is possible the $/GJ pipeline costs could be greater in the South Island due to South Island demand being smaller, and more dispersed than the North Island. If this is the case, it will lower the price at which upstream producers could sell their gas and still be competitive against coal or biomass alternatives.
- future CO₂ prices
- the development cost of the options (e.g. the cost of developing LNG liquefaction facilities)

It should also be noted that these prices are the prices that would be paid for gas for which there is no field reserves risk. It is possible that reserves risk will result in a material discount in the above prices which could be achieved by a New Zealand gas producer.

The graph distinguishes between those options for which there is likely to be an effectively ‘unlimited’ demand for any product that New Zealand can produce, and those for which demand could be materially constrained. This is likely to be a significant issue when considering options which could help commercialise significant new gas finds.

Overall it would appear that for very large gas discoveries, LNG would represent the most valuable development opportunity. For sub-LNG-scale discoveries, new petrochemical developments appear to represent the best opportunity for commercialisation. Taken together, these options mean there should be a ready source of demand for significant New Zealand gas discoveries. As such, New Zealand should not be disadvantaged for exploration investment relative to other locations around the world which are distant from the ‘core’ oil and gas markets of the US, Europe and Asia.

Demand constraints will mean that the other options will be unlikely, on their own, to facilitate the development of significant new gas discoveries. However, for each of these options there could be opportunities for profitable development on a case-by-case basis.

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8 Reserves risk is the risk that the quantity of gas in a field turns out to be less than expected.
9 Oil and gas produced in these core markets will always be more valuable than produced in more distant locations, due to avoided transport costs. However many of these core markets have limited indigenous sources of oil and gas, and/or have sources which are relatively high cost to extract.
1 Introduction

In October 2014, Gas Industry Co published an update to the New Zealand gas supply / demand study\textsuperscript{10} which explored the factors that were likely to influence gas outcomes for New Zealand, and considered possible futures for the New Zealand gas sector.

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2 LNG export

2.1 Global LNG developments

Several major economies are located such a distance from major gas fields that transporting gas by pipeline is not economic. Similarly, several major gas fields are located distant from major energy-consuming economies.

Over the last thirty years, LNG has emerged as a technology which can ‘join’ these two sides of the energy equation. This is illustrated in the following figures.

Figure 4 shows that the main LNG-consuming economies have been Japan, South Korea and Taiwan, all of whom have little indigenous energy resources to call upon. More recently, China and Europe have started to consume LNG to make-up for shortfalls in indigenous energy and pipeline imports.

*Figure 4 - Global LNG imports*

Figure 5 shows the major LNG producers. These are all areas of the world which have indigenous gas resources significantly in excess of their domestic energy needs, and which are too far from the main gas consuming economies (US, Europe, Far East) to export gas via pipeline.
LNG production and transportation is a very capital intensive business. The capital cost of individual projects can range from US$5bn for relatively small projects, through to US$50bn+ for large projects. As a result, until recently, almost all LNG projects have been underwritten by long-term (typically 20 years) bilateral sales contracts with individual purchasers.

The pricing of these contracts has typically been strongly linked to the price of oil. The most common form of pricing for LNG exported to Japan has been the so-called “Japanese Crude Cocktail”. This directly links the price of LNG to the price of a pre-determined bundle of different categories of oil through a multiplier plus a constant.

The multiplier has generally been set to achieve an energy price which is close to parity with oil on an energy equivalent basis. i.e. setting the price so that the price of oil and the price of LNG are similar on a $ per mmBtu basis. The multiplier varies between contracts: sometimes the LNG price is at a discount to oil on an energy equivalent basis, and occasionally it is at a premium. If oil is priced in US$/bbl, the multiplier would be approximately 17% in order to translate directly to an energy equivalent LNG price expressed in US$/mmBtu.

The constant is generally set to reflect the cost of transporting the LNG. From Australia to Japan, this transport cost is approximately US$1/mmBtu.

This close linkage with the price of oil can be seen in the following figure which compares the average Japanese LNG price with the average oil price, both on a US$/mmBtu basis.
This oil-linked pricing approach reflects the fact that in many countries gas is used principally as a substitute for other forms of energy, such as oil. In addition, oil markets have been perceived by LNG producers and customers as being relatively transparent and competitive, favouring neither buyers nor sellers over the longer term. This is in contrast to gas markets (which arguably should be an even better price marker for LNG), which historically have lacked transparency and have often been subject to limited competition or heavy state intervention.

For similar reasons, this oil-linked pricing approach has also been applied to many of the long-term contracts for supply of gas via pipeline into Europe from countries such as Russia.

However, developments over the last decade are starting to alter this dynamic of LNG being principally developed via long-term bilateral supply contracts and priced on a substitution-basis with oil.

Figure 7 below shows historical gas prices for three main markets (US, Europe, and Japan), along with historical oil prices.
As can be seen, up until 2008 the price of gas in all three markets was strongly linked to the price of oil. However, in 2009 the US gas price started to completely decouple from the price of oil. This was a result of the revolution in hydrocarbon production in the US, whereby new techniques (colloquially known as ‘fracking’) resulted in a huge increase in US gas (and oil) production from shale beds. This massive increase in gas supply meant that gas prices fell to the cost of gas production, and US gas pricing is now principally driven by the supply / demand balance for gas.

Europe too has seen some decoupling, partly due to subdued consumer demand following the GFC, but partly also due to on-going initiatives to liberalise gas pricing so that it is driven by the supply / demand fundamentals of gas production, rather than being linked to oil pricing.

This revolution in US gas production and pricing is now starting to be felt in LNG markets. A large number of LNG developments are either underway or proposed in the US and Canada. Not only do these developments represent a large proportion of the LNG market, but many of them are being priced in a completely different way to the old oil-linked contract approach. Most new US LNG developments are being priced on a so-called Henry Hub linked basis.

Under this approach, LNG is sold to customers at a price linked\(^\text{11}\) to the main US gas market trading hub – Henry Hub – plus a fixed market up of approximately US$5-6/mmBtu to cover the fixed costs of developing the liquefaction facilities and transportation costs. Given estimated transport costs of US$2.5/mmBtu, this suggests the fixed liquefaction costs of these US Gulf coast facilities are approximately US$2.5-3/mmBtu.

\(^{11}\) Typically the price is Henry Hub plus 15%, to reflect the significant amount of gas that is consumed during the liquefaction process.
Based on recent, and projected future, Henry Hub prices of approximately US$3-5/mmBtu, this results in a delivered price into Japan of approximately US$10-12/mmBtu. This is substantially lower than the oil-linked LNG contracts which, until very recently, were priced at the US$16-17/mmBtu range.

The advantage of such pricing for US LNG producers is that it de-risks their exposure to gas and oil price fluctuations, and they can instead make a consistent return on their LNG production assets. They in effect become a tolling operation.

This risk benefit for US LNG producers has been thrown into sharp focus over recent months with the collapse in world oil prices. With world oil prices below US$70/bbl, Japanese LNG prices are likely to fall to below US$10/mmBtu.

The consequences of both these recent developments have been significant for existing LNG players.

Australia has seen the most significant recent growth in LNG production, with seven major LNG production facilities currently being developed. These projects have been developed on the back of long-term, oil-linked supply contracts to Asia. As such, they are largely protected from the emergence of the lower-cost US LNG producers. However, they have been plagued with major cost overruns which, coupled with the recent drop in oil prices, means that they are all facing various degrees of financial distress. In this respect, the break-even Asian LNG price for some Australian developments has been estimated to be approximately US$12-14/mmBtu, with others potentially having even higher break-even prices.

A significant number of additional Australian LNG projects have also been proposed. However, these look vulnerable to the potential new LNG production coming from North America – much of which appears to be lower cost than the Australian projects. In this, Australian projects appear to be higher cost due to a combination of:

- The Australian developments being greenfield developments – many in remote places – compared with the US developments which are predominantly brownfield, being developed in existing petrochemical industrial areas, and many of which have been able to adapt infrastructure which was being developed in the early 2000’s for LNG imports.

- The US developments being able to access a deep skilled labour pool, whereas the Australian developments having to struggle to attract such a significant increase (for the size of the Australian economy) in skilled labour – particularly for remote locations.

It is reasonable to assume that US Gulf Coast developments could be price-setting for the LNG market in the long-run. As set out above, this could result in long-run Asian prices of approximately US$10-12/mmBtu. $12/mmBtu is also the price that many oil-linked contracts would arrive at for oil prices of US$70/bbl.

However, such an outcome will only occur if significant amounts of new US LNG developments are developed. In this it is noteworthy that LNG export developments must receive Federal government approval before being allowed to go ahead, and that there has been some opposition to LNG export within the US from domestic consumers of gas. These parties have opposed LNG export due to the fact that such export will act to increase the domestic US price of gas.

Although the overall benefit to the US economy from LNG export has been demonstrated to be positive, this impact of rising domestic US prices does add a political dimension to the issue.

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13 This is also a big issue in Eastern Australia, where the development of LNG export facilities means the domestic Australian gas price is rising to LNG export parity prices.
14 See, for example, “Macroeconomic impacts of LNG exports from the United States”, NERA, December 2012
Accordingly, it is possible that there may be some political constraints on the extent of expansion of US LNG export developments.

To the extent that there are some constraints on US LNG expansion, other LNG developments around the world are likely to be the marginal source of supply to meet global LNG demand – with a consequentially higher global LNG price. This is illustrated in the following figure from a recent McKinsey note on the global LNG market.

**Figure 8: Global LNG cost curve**

![Global LNG cost curve](image)


Based on the above analysis, it therefore appears reasonable to assume long-term Asian LNG prices of approximately US$11-14/mmBtu.

Whatever the long-term equilibrium outcome, on a year-to-year basis there is likely to continue to be significant swings in LNG supply / demand balance – reflecting the ‘lumpy’ nature of new LNG developments, and the fact that LNG is a ‘balancing’ source of energy for these energy-poor LNG-consuming economies. Shifts in overall energy demand in these economies could have major impacts on demand for LNG. In addition, developments such as pipeline gas from Russia could also have significant impacts. Therefore short-term LNG prices could exhibit significant swings around this long-term mean.

In particular, in the short- to medium-term it is possible that LNG prices will be softer than the long-term range postulated above due to a combination of two factors:

- Lower Asian demand for LNG than expected due to:
  - Japan starting to restart some of its nuclear reactors following the Fukushima disaster; and
  - Relatively slow Asian economic growth than seen in previous years.
- A significant amount of new LNG production capacity starting to come on stream over the next couple of years, particularly from Australia.
2.2 Implications for New Zealand

2.2.1 Is LNG a realistic option for New Zealand?

If significant gas is found in New Zealand, a number of factors will determine whether it is likely to be economic to develop for LNG.

The first is the size of the field. Although there is not a huge amount of public data on LNG development costs, what little exists suggests that there are some economies of scale associated with LNG production. While there have been some relatively small LNG developments overseas (e.g. 1 Mtpa production, associated with a field of approx. 1,000 PJ in size), it is possible that many of these have been associated with brownfield developments, and thus can take advantage of the significant economies associated with such brownfield status (as demonstrated by the US LNG developments, described on page 17). Thus, it is possible that a more realistic threshold size for LNG development in New Zealand would be 3-4,000 PJ (i.e. similar to the Maui field). This is consistent with statements from the likes of Shell which described “smaller” offshore gas-condensate fields suitable for LNG production as being approximately 3,000 -5,000 PJ\(^\text{15}\). However, this threshold size will be strongly influenced by the second factor.

This second factor is the cost of producing the gas (i.e. extracting it from the ground, before liquefying it). Gas which is found in challenging terrain (e.g. deepwater), and/or difficult geology (e.g. tight gas which requires a lot more production wells) will cost a lot more to produce. This high production cost will reduce the amount of money which can be spent on developing the liquefaction facilities and still be profitable against the competing sources of LNG production which will likely set the long-run price for LNG. This second factor will itself be significantly influenced by a third factor.

This third factor is the extent of any associated liquids which will be extracted at the same time. Any liquids extraction will help to offset the cost of gas production. Therefore, fields which have a relatively high proportion of liquids will have a lower effective cost of gas production.

The next factor is the cost of developing the liquefaction facility. As mentioned above, on a $/mmBtu basis, this will be influenced by the size of the facility, but it will also be influenced by the location. Until relatively recently, all LNG liquefaction facilities have been developed onshore. However, many of the Australian developments have suffered ballooning costs. As detailed on page 17, part of this relates to the greenfield nature of these facilities, but part also appears to relate to the challenge of bringing such a large (when compared to the general size of the working population) skilled workforce together – particularly for some of the more remote locations. A recent report\(^\text{16}\) suggests that these onshore facilities are resulting in liquefaction costs of US$5-6/mmBtu, compared with overseas developments including in the US Gulf coast, of approximately US$2-3/mmBtu.

It is likely that New Zealand LNG developments would also suffer this challenge of pulling together a large skilled workforce for such a major capital project. However, it is possible that this cost could be mitigated through the development of a floating LNG production facility. These have only recently been developed for a few projects, including the Prelude development off the NW coast of Australia. Although they were originally developed as a means of commercialising gas in deepwater locations, as set out in Box 1 below, they are increasingly being recognised as providing cost advantages which may make them the best option – even for close-to-shore developments.

\(^{15}\) “Browse decision highlights cost benefits of FLNG”, Gastech paper, September 2013
Box 1: Floating LNG production

In recent years one of the most significant new developments in LNG production has been the development of floating LNG-production facilities. These facilities offer significant cost advantages compared to onshore LNG production facilities, including:

- Being able to be built in locations with significantly cheaper labour costs, and being more ‘off-the-shelf’ in design. This may be particularly advantageous for locations that are remote from a large pool of engineering labour. (Such as New Zealand, and some remote Australian locations).
- Being able to be re-deployed to another location at the end of the field’s economic life, providing some additional value, and substantially reducing decommissioning costs – which can be significant.
- Not incurring the extra cost of an offshore platform and the development of a pipeline to take the gas and oil to shore

Because of these cost advantages, floating LNG production is becoming the preferred choice for developing LNG in offshore fields, rather than bringing it onshore for processing.

It is therefore possible that any LNG-scale gas finds in New Zealand would be developed via floating production, storage and offloading (FPSO) vessels. Estimating the cost of this is challenging. One estimate of a project similar to the Prelude development off NW Australia suggests costs of approximately US$2,000/t/y (≈ US$4.8/mmBtu). Another proposed FLNG project in the US has costs estimated at approximately US$600/t/y (≈ US$1.5/mmBtu). However, this is a near-shore development taking pipeline gas from the mainland, so may enjoy lower costs. (As an aside, this near-shore development shows how floating liquefaction facilities are starting to be viewed as lower cost options than onshore facilities – even when the gas is itself onshore).

On balance, it therefore appears that a FLNG deepwater development will have liquefaction capital costs of approximately US$4-5/mmBtu for a Maui-sized development.

The last factor influencing the relative economics of a gas field for LNG is transport costs to the end market – i.e. East Asia. In this, New Zealand has an advantage compared to the US Gulf coast. Whereas the cost for shipping from the US Gulf to Japan is estimated to be approximately US$2.5/mmBtu, for New Zealand it is approximately US$1/mmBtu.

Taken together, it appears reasonable that a gas find of approximately 3-4,000 PJ in New Zealand could be economic to develop for LNG. Relative to US Gulf Coast developments, the cost premium from developing in a greenfield location remote from a deep skilled engineering labour pool will be significantly offset by the transport cost advantage in terms of shipping product to East Asia. Further, the development of FLNG technology should significantly reduce any cost disadvantage that New Zealand may suffer relative to other greenfield locations.

That said, the specifics of a potential find will have a huge bearing on whether it will be economic to develop – in particular the extent to which it has characteristics which will result in a high gas production cost.

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17 "Browse decision highlights cost benefits of FLNG", Gastech paper, September 2013
18 Ibid
2.2.2 If a discovery is too small for LNG, is it too small for any production?

As set out previously, it is possible that the threshold size for fields to be economic to develop for LNG production will be approximately 3-4,000 PJ.

This raises the question of whether discoveries smaller than this will be too small to develop at all. In many cases, particularly in frontier locations distant from the existing Taranaki gas processing infrastructure, the answer will be likely to be yes. As set out in Section 3, it is likely that the price at which gas could be sold to new sources of demand in New Zealand, such as a petrochemical producer, will be approximately NZ$3-4/GJ. For new, smaller, gas fields – particularly in offshore locations – it is likely that the development and production costs could be similar to, or greater than, this price, thereby rendering development uneconomic.

However, if the field is predominantly an oil field, it is possible that the sale of liquids could justify the field’s development. If there is associated gas, the evaluation is then around whether it is economic to re-inject the gas, or spend the money to bring it ashore\textsuperscript{19}. This evaluation is going to be very field specific, and depend on the relative costs of the options given the location of the field:

- The further offshore the field, and the more challenging the geology, the less likely it will be economic to bring it ashore
- If the field is near existing gas production and processing infrastructure which could be used, this will improve the economics of bringing the gas ashore. The Ruru prospect is an example of this, with the potential to use infrastructure built for the Maui field.
- The extent to which any liquids production is sufficient on its own to justify the field’s development, or whether there is some level of gas sales required to make the field economic.

Because these are very situation-specific factors, it is hard to generalise. However, it is highly conceivable that if a liquids-rich field was discovered which had significant associated gas, but which was too small to justify an LNG development, it could be possible to develop a pipeline to shore and gas processing for less than NZ$3-4/GJ.

If the location of such a field was distant to the existing Taranaki-based gas infrastructure, section 3 sets out that it should be possible to commercialise such gas through a new petrochemical investment such as methanol or urea production.

2.2.3 Should LNG-scale offshore gas be brought onshore?

As set out earlier, most of the exploration in the South Island is located offshore, and explorers are actively seeking gas of a scale that is large enough to justify LNG production.

It is possible that any gas that is found will be brought onshore for processing. However, for the reasons set out in Box 1 above, developments in LNG technology over the last few years mean that there is an increasing likelihood that such gas will be processed entirely off-shore in floating production, storage and offloading (FPSO) vessels before being exported overseas.

In this context, one issue that has been raised by some stakeholders is whether it may be preferable to bring all or some of the gas onshore to boost economic development in the South Island.

To achieve this would likely require some form of government intervention which would either result in the gas (and any associated oil) being brought ashore for processing in land-based LNG liquefaction plant, or the development of a pipeline from the FPSO vessel to bring already processed gas ashore. Overseas this has been achieved through measures such as ‘reservations’ policies, or

\textsuperscript{19} Improved environmental legislation means that flaring the gas is no longer an option.
direct government intervention in the field development plan in terms of how and where the hydrocarbons should be processed.

Such interventions could potentially be justified if greater overall economic benefit to New Zealand could be achieved from bringing the gas ashore, but the cost-benefit signals as seen by the developers of the field resulted in them preferring offshore processing.

This study considers at a high-level whether this could potentially be the case in New Zealand, by looking at the relative economics of offshore versus onshore options.

The two main aspects of this consideration are:

- What might be the incremental revenues from consuming gas on-shore, compared with selling it as LNG?
- What might be the incremental costs from requiring gas to be brought ashore?

**Incremental revenues from consuming gas on-shore, compared with selling it as LNG**

If it were the case that consuming the gas on-shore could earn greater returns than selling it overseas as LNG, there may be merit in bringing some of the gas ashore.

As was set out on page 18, a reasonable estimate of future LNG prices range from US$11.14/MMBtu.

Converting this to NZ$/GJ, using a long-term exchange rate of 0.7 NZ$/US$, and subtracting estimated LNG shipping costs from New Zealand to Asia, results in a price range for LNG produced in New Zealand (i.e. the ‘free on board’ (fob) price) of between NZ$13.5/GJ and NZ$17.5/GJ.

Further, there are considerable costs involved in liquefying the gas which would be avoided if it were consumed on-shore in New Zealand. Accordingly, the required on-shore price to achieve the same value as off-shore LNG sales should be the LNG fob price less these costs associated with LNG production:

- The process of liquefying the gas is estimated to consume approximately 15% of the gas. Avoiding this cost would bring the NZ equivalent price range for un-liquefied gas down to between NZ$11.5/GJ and NZ$14.9/GJ.
- Consuming un-liquefied gas on-shore should enable a smaller liquefaction facility to be built. The amortised capital component of the cost of LNG is estimated to be approximately NZ$5/GJ. If the cost of LNG liquefaction facilities scale completely with size, then the full NZ$5/GJ should be subtracted to give an equivalent on-shore value price. In reality, there are probably scale economies with such facilities. There will also be some other processing costs that will not be avoided (such as drying and removing impurities). This means that only some proportion of this NZ$5/GJ capital recovery cost will be avoided.

On balance, this very simple methodology suggests that producers would need a domestic gas price of between NZ$7.5 to NZ$13/GJ to equal the effective price they would receive from exporting LNG.

As set out later in this report, a domestic price of NZ$7.5 to NZ$13/GJ is higher than New Zealand industries would be prepared to pay:

- It is significantly greater than petrochemical producers would be prepared to pay to underpin a new methanol or urea production facility (see section 3);

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20 The free on board (fob) price represents the price of a good loaded onto a ship at the exporting country. This compares with the carriage insurance and freight (cif) price which represents the price of a good at the destination port of the importing country. i.e. it is the fob price plus the cost of international shipping.
• It is likely to be greater than the price a new combined-cycle gas turbine could afford to pay to compete with new geothermal and wind generation (see section 5); and
• It appears to be greater than the price South Island industrial consumers would be prepared to pay to switch to gas rather than coal or biomass (see section 6.2).

Further, as set out in subsequent sections, there is likely to be limited demand for gas-fired electricity generation or gas-fired industrial process heat in the South Island. This means that only petrochemical production offers the option of significant gas consumption, the products of which would predominantly be exported overseas. (As would the milk powder from South Island industrial process heat).

Therefore, there would appear to be no benefit in reserving gas to be ‘exported’ in the form of petrochemicals or milk powder, when it could be exported in the form of LNG and achieve significantly higher value.

In the case of using gas for dairy production, it should additionally be appreciated that any sub-market price gas consumed would be displacing domestic fuel sources – namely coal or biomass – with consequent negative impacts on these domestic industries.

Further, such a reservations policy is effectively a tax on LNG producers, and will lower the returns that such a producer could earn on the project. This will make it less likely that the project will go ahead at all, as the reduced returns may be less than those which oil and gas companies could earn from other potential LNG development projects in other countries.

**Incremental costs from bringing gas ashore**

If a political decision were made to bring the gas onshore for processing when the developer would have preferred to process the gas offshore, this will inevitably result in a higher processing cost – because why would a developer choose a more expensive development option?

Based on overseas experiences in places such as Australia, it is entirely feasible that an on-shore processing plant could cost at least 10% more than an off-shore facility. Given that an LNG production facility is likely to cost of the order of $10 billion, this equates to a $1 billion increase in the project costs. This may jeopardise the project’s economics.

In this it is noteworthy that a number of overseas LNG developments (e.g. East Timor, and the Browse field off North Western Australia) have stalled because the developer wants to pursue a cheaper floating LNG development option, but the local government wants a land-based liquefaction facility, because of the economic development it would bring to the region. There appears to be a real possibility that, the extra cost and delays caused by the local governments may cause the projects to be cancelled, and the LNG demand they were going to service will instead be met from developments in the US and Africa. As a result, in seeking to get a larger economic benefit, the governments of East Timor and North Western Australia may end up with no economic benefit.

Given the likely high development costs for a greenfield (and internationally remote) on-shore LNG production facility in New Zealand, there is a risk of similar outcomes occurring if government intervention sought to mandate on-shore development instead of floating production.
3 New petrochemical plant

As well as being used as a fuel, hydrocarbons are used as a feedstock to make a wide variety of different petrochemical products. The most common end products include fertilisers, plastics, resins, fibres, elastomers, lubricants, gels, solvents, detergents, and adhesives.

Through breaking down and recombining various molecules, these petrochemical products can be produced from a wide variety of the different hydrocarbons which form natural gas and petroleum.

Such hydrocarbons range from ‘light’ molecules such as methane and ethane which occur as gases at atmospheric pressure, through to heavier molecules which occur as liquids at atmospheric pressure.

This section focusses on the petrochemical options to commercialise methane and ethane in New Zealand. This is because, as set out in Box 2, the heavier hydrocarbons (propane and above) form the smaller proportion of the raw gas stream, and are able to be extracted and sold in their own right to customers in New Zealand or overseas. Indeed most of these liquids are currently extracted and sold in this fashion in New Zealand.

Thus, they do not face the same constraints that methane and ethane currently face in terms of needing to be consumed within New Zealand in order to be commercialised.

Methane has been converted to petrochemical products in New Zealand for many years, including for the production of methanol, urea, and synthetic petrol (synfuel).\textsuperscript{21} Section 3.2 considers the likely economics of possible new methane petrochemical processing facilities.

However, section 3.1 first considers whether petrochemical production options exist for converting ethane in New Zealand.

3.1 Petrochemical options for ethane

The principal petrochemical option for ethane is the production of ethylene.

This is a primary petrochemical feedstock which is used in the manufacture of a large number of intermediate petrochemical feedstocks and ultimate end-use products. It is an internationally traded commodity, transported by ship.

\textsuperscript{21} As discussed in section 4, synfuel production has been discontinued in New Zealand.

\textbf{Box 2: Extraction of liquids from the gas stream}

‘Raw’ natural gas in a gas field consists principally of methane (CH\textsubscript{4}), but also contains smaller proportions of heavier alkanes, often referred to as ‘natural gas liquids’ which are: Ethane (C\textsubscript{2}H\textsubscript{6}); Propane (C\textsubscript{3}H\textsubscript{8}); and Butane (C\textsubscript{4}H\textsubscript{10}).

For many of New Zealand’s gas fields, the propane and butane are extracted and sold as liquefied petroleum gas (LPG). LPG is principally used as a fuel – both for heating and transport. Much of the LPG is consumed within New Zealand, but a significant amount is exported.

Currently the ethane is not extracted in New Zealand, but is included within the gas stream reticulated to end consumers (along with any propane and butane which hasn’t been extracted from some fields).

The gas extracted from a field often includes even heavier alkanes such as pentane (C\textsubscript{5}H\textsubscript{12}), hexane (C\textsubscript{6}H\textsubscript{14}) and above. These are extracted from the gas during processing as liquid condensate. This condensate is principally used for production of automotive fuel. It is mostly exported from New Zealand to be refined overseas, although some may be sold to the New Zealand Refinery for production of fuel for consumption in New Zealand.
Ethylene is produced in processing plants known as steam crackers. As the figure below shows, a variety of different input hydrocarbons can be used to create ethylene:

- Natural gas liquids (i.e. ethane, propane, and butane) which are extracted from gas processing plants;
- Naphtha and Gas Oil from a petroleum refinery.

![Diagram of ethylene production](image)

Which input hydrocarbons are used to produce ethylene varies according to the specifics of different countries’ situations. For example, in the Middle East a large amount of ethylene (and other primary petrochemical feedstocks such as propylene, benzene, etc.) is produced from steam crackers attached to petroleum refineries using liquid feedstocks as the principal input. In the United States a number of crackers are being developed which use the large amounts of the ethane being produced in shale gas. Typically, these so-called ethane-based crackers are also located in oil refineries and use some of the liquid streams for cracking.

However, for New Zealand, it is considered that the production of ethylene does not represent a realistic option to commercialise significant proportions of any new gas that is found. This is largely because of the small proportions of ethane involved.

For example, ethane makes up approximately 10% of the natural gas for both the Kapuni and Kupe fields. Public data on the proportion of ethane for the other fields has not been found. However, 10% is understood to be a relatively high proportion compared with other gas fields overseas.

If a 1,000 PJ gas field (i.e. similar to Pohokura) were found which had 10% ethane, and an extraction profile of 20 years, this would equate to approximately 5PJ of ethane being produced per annum. This is not considered to be of a scale which is large enough to invest in a steam cracker for the production of ethylene. Further, because the Northland location of the New Zealand refinery is distant from the location of gas processing in New Zealand (i.e. Taranaki), it would not be practicable to undertake steam cracking at the refinery and take advantage of the co-location benefits with the other petroleum refining activities there.

A significantly larger field could justify the development of a steam cracker for ethylene production. However, once a field reaches such a scale, it is likely to be more economic to develop it to produce liquefied natural gas (LNG) for export.
3.2 Petrochemical options for methane

3.2.1 Options for consideration

The principal petrochemical conversion options for methane are:

- **Methanol.** This is a primary petrochemical feedstock used for a variety of applications. It is also increasingly being used as a fuel source. There are two methanol production facilities in New Zealand located in Taranaki: the single production train Waitara Valley facility, and the dual train Motunui facility. Operating at full capacity the annual consumption of gas for each site is approximately 20 PJ and 70 PJ, respectively.

- **Ammonia.** This is a primary petrochemical feedstock used for the manufacture of a variety of end products, including fertilizer, cleaners, and various nitrogenous compounds.

- **Urea.** This is a fertilizer. It is generally produced in integrated ammonia-urea production plants, and accounts for the majority of ammonia produced worldwide (≈ 85%). There is a single urea production facility in New Zealand – the Kapuni plant – which consumes approximately 7 PJ of gas annually.

- **Synthetic fuels** used as petrol or diesel substitutes. Synthetic petrol used to be produced in New Zealand at the Motunui site from 1986 until it was closed in 1996.

Section 4 considers the issues in relation to the prospects for another Synfuels production facility in New Zealand.

The report Long Term Gas Supply and Demand Scenarios\(^\text{22}\) considered in depth the factors likely to affect gas demand for existing petrochemical facilities in New Zealand (Methanex’s methanol-producing plants and Ballance’s urea production facility). This section considers whether methanol, ammonia, or urea production provide attractive options for the construction of new facilities to commercialise a new gas find in New Zealand, including what price and scale may be achieved, and what other factors may drive outcomes.

3.2.2 Factors driving the relative economics of different petrochemical options

Around the world, all three commodities represent realistic options for commercialising significant new parcels of gas.

They are all internationally traded, requiring the same basic input (natural gas), and similar production processes. They all require production facilities of broadly similar scales to achieve reasonable efficiency levels (albeit with some differences between the commodities). Thus, depending on the quantity of gas available, relatively ‘small-scale’ facilities consuming 20-30 PJ/yr appear to be feasible, through to much larger scale facilities consuming ≈ 90 PJ/yr.

Which commodity is likely to be most appropriate for commercialising new gas at a particular time and place will depend on three factors:

- **Where each of the commodities is currently located on its ‘cycle’ of fluctuating supply and demand.**

  If the world price for one of the commodities is particularly high, it will increase the likelihood of owners of gas resources investing in producing that commodity rather than the other options. This will have the effect of bringing supply and demand for that commodity back into balance,

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and reducing prices. These supply / demand pressures should mean that, over the long-term, the gas net-backs from methanol, ammonia and urea should be roughly the same.

However, in the short-term there can be significant differences between the commodities as they are all characterised by highly capital intensive production facilities, which have significant lead-times to build. This can mean there can be significant lags between the level of demand changing, and the available supply capacity changing to meet the changed demand. This can give rise to cyclical pricing swings as the supply / demand balance moves between situations of relative supply scarcity and relative supply surplus.

At the moment, it does not appear that any of the three commodities is particularly highly priced relative to the others. Prices for all three appear to be at a level high enough to support the development of new world production capacity – as is indeed happening, with several new production facilities for all three commodities being developed around the world.

- **Scale issues.**

  Although the efficient scale of production is similar between the different commodities, it appears that the required scale for modern methanol plant may be somewhat larger than the required scale of a modern ammonia or urea plant. Thus, if the amount of gas needing to be commercialised is relatively ‘small’ – i.e. 15 to 20 PJ/yr, this may favour ammonia or urea, rather than methanol.

  In the specific situation of New Zealand, another factor that may favour a new urea production facility if a relatively small quantity of gas needed to be commercialised, is that there is an existing relatively small scale (7 PJ/yr) facility at Kapuni for ammonia urea production. This plant was commissioned in the 1980s and it is not clear when major capital expenditure will be required to extend its life. If it were to be replaced, a (say) 20 PJ/yr new facility would represent additional gas consumption of 20 – 7 = 13 PJ/yr.

- **Whether there is a significant local demand for the product.**

  International freight costs can be a significant proportion of the end product price for all three commodities - approximately 10-15%.

  Any local demand for the product will avoid these freight costs, giving a significant cost advantage.

  In this respect, New Zealand has significant local demand for urea (and indeed imports approximately two thirds of the urea it uses), whereas it has relatively little demand for methanol and ammonia. This is likely to substantially favour the relative economics of developing a new urea production facility in New Zealand. Further, Australia is a significant consumer of urea and is a likely demand source for any production of urea that exceeds New Zealand demand. (At the moment, both Australia and New Zealand source a significant proportion of their urea from the Middle East and Canada.) In contrast, the main export markets for any methanol and ammonia would likely be the more distant markets of China and other Asian countries. The existence of local demand will give urea freight advantages.

  This situation of a new urea production facility having a significant advantage over new methanol and ammonia production is likely to continue, even if material amounts of methanol start to be used to meet New Zealand’s vehicle fuel demand. This is because, as set out in 4.7.2, the scale of any local transport-based methanol consumption will likely be only slightly more than the output of the smallest of Methanex’s three production trains under a generous uptake scenario. Accordingly, any new methanol production train will effectively be producing all its output for export to offshore markets.

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23 Noting that there is ship borne trade in methanol (export) and urea (import) between New Zealand and offshore markets.
Based on the above, it would appear that the petrochemical option which could achieve the highest gas netbacks would be a new urea facility. This is principally because of the significant amount of domestic New Zealand consumption of urea and the associated cost advantage of avoiding freight costs. It also appears to be better suited to commercialising smaller parcels of gas than a modern new methanol train.

3.2.3 Estimating the potential scale and gas net-back for a new Urea facility

The left hand half of Figure 9 below illustrates the scale associated with current Australasian urea consumption and production, and the right hand of the graph translates this into the equivalent quantity of gas associated with its manufacture. The equivalent gas quantity figures are shown both for:

- a potential modern new production facility located in New Zealand set at a size to exactly meet the combined Australasian demand for urea; and also
- for the existing Australasian production facilities. (One in New Zealand at Kapuni, and one in Australia).

Figure 9: Estimates of Australasian urea consumption and gas equivalent associated with its manufacture

As can be seen, the current Kapuni urea facility consumes approximately 7 PJ of gas per year. If a new facility was developed to meet the entire NZ and Australian demand for urea (displacing the existing NZ and Australian production facilities), this would consume approximately 40 PJ of gas per year.

Source: Concept analysis

24 In the absence of regional consumption data, an estimate of the split between North and South Island urea consumption has been made based on reported milk production statistics for the two islands.
It is understood that there are some scale economies in production facilities, although little information is available on the extent of such economies.\textsuperscript{25} Therefore the optimal sized plant will depend on any trade-off between:

- the quantity of gas available (noting that investors in new petrochemical production facilities generally seek surety of gas for approximately 15 to 20 years);
- any scale economies; and
- the relative size of the New Zealand and Australian markets.

\textit{Shipping cost impacts}

With respect to this last point, any local consumption of New Zealand produced urea would avoid international shipping costs. A reasonable reference point for international urea that is imported for New Zealand consumption is Middle East Granular Urea. Currently urea shipping costs from the Middle East to New Zealand appear to be \textapprox US$35/tonne. Using a long-term exchange rate of 0.7 US$/NZ$, and the conversion of efficiency of gas to urea in a modern plant, equates to a gas-equivalent cost of \textapprox NZ$2.5/GJ. This is a considerable cost advantage which would likely be reflected in any urea producer’s willingness to pay for gas in New Zealand.

However, production above a certain scale will exceed the demand from the local New Zealand market and the urea will need to be shipped overseas. This will significantly reduce the cost advantage from avoided shipping. In this respect, inter-island shipping costs (i.e. between the North and South Island) are understood to be almost as significant as between New Zealand and Australia. Nonetheless, shipping from the North Island to the South Island or to Australia is likely to be less expensive than shipping urea from the current sources of urea for import into Australasia – namely the Middle East or Canada. The scale of relative cost advantage is not known, but high-level analysis suggests it could be of the order of US$10/tonne \textapprox NZ$0.7/GJ.

Looking at Figure 9 above, it appears that a North Island located new urea production facility would avoid international shipping costs (worth approximately US$35/tonne) up to a gas-equivalent scale of approximately 10 PJ/a. Production above this level would need to be shipped to the South Island or Australia, and have a US$10/tonne price advantage compared to Middle East or Canadian sourced Urea.

It is understood that a large number of ‘generic’ urea plants are being built overseas whose urea production capacity is approximately 1,350 kt/a. It is understood that manufacture of a plant of this scale could achieve some scale economies. A plant of capacity 1,350 kt/a equates to gas consumption of approximately 27 PJ/a.

Assuming that shipping costs of NZ$2.5/GJ are avoided for the first 10 PJ gas equivalent of production, and NZ$0.7/GJ for the remainder, it appears that such a facility could enjoy a weighted average avoided gas equivalent shipping cost benefit of approximately NZ$1.35/GJ.

There has also been discussion that Ballance may invest to bring the current Kapuni plant up to world efficiency standards. This may substantially increase Urea output by 40-50%, but with only a relatively small increase in gas consumption.

If this happens, it will mean the upgraded plant will provide approximately 85% of the North Island’s urea requirements. It is unlikely that it would be cost-effective for such an upgraded new plant to be displaced by a brand new, and much larger, urea plant built on the back of a significant new gas find.

\textsuperscript{25} There were differences of view between individuals spoken to in the petrochemicals sector regarding the extent of scale economies for different sized production facilities. One individual suggested the scale economies were significant, whereas another suggested they were not that material.
Accordingly, it would mean that any such new plant would need to supply a greater proportion of its output to the Australian market or the South Island market, where the shipping cost advantage relative to international sources of urea is only NZ$0.7/GJ.

**Influence of alternative international locations for new petrochemical production facilities**

Other than this avoided shipping cost benefit, the price which a urea producer would be willing to pay for gas would be set with reference to the marginal source of new global urea production. A urea producer would be unwilling to pay more for gas in one location than it could pay for gas to produce urea in another location – factored by the benefit (or cost) of reduced (or increased) shipping costs associated with different locations.

The marginal source of new urea (and other petrochemical production) currently appears to be North America. The shale gas revolution has unlocked vast quantities of new gas reserves and led to a significant fall in North American gas prices. This lowered gas price has unleashed a significant amount of new gas projects, including gas-fired power generation, various forms of petrochemicals manufacture (including methanol, ammonia, and urea), and LNG export.

It is therefore likely that North American gas prices will set a ceiling on parties’ willingness to pay for gas to manufacture the above commodities in other locations around the world – except to factor in the effect of relative shipping costs.

To get an understanding of the possible scale of such prices, Figure 10 shows the current forward curve for two key North American trading hubs: Henry Hub (located in the Gulf Coast of the United States), and Alberta (a western Canadian province).

*Figure 10: Forward curves for North American Gas prices*

Source: Concept analysis using CME and GasAlberta data

The key points from this graph are:

- North American gas prices are projected to rise over the next five to six years. This is understood to be the effect of a significant number of new gas consuming facilities coming on
line and reducing the extent of surplus in the North American gas supply / demand balance. New LNG export facilities are understood to be particularly significant in this respect.

- Gas prices for Alberta are currently projected to be approximately US$0.8/mmbtu lower than Henry Hub prices for at least the next 4 to 5 years. This is understood to be due to the relative surplus of gas in Alberta relative to the US Gulf Coast and the impact of gas pipeline costs between the two locations. Coincidentally, to get to the Canadian West Coast, it is understood that gas transmission charges are approximately US$0.8/mmBtu. Accordingly, Henry Hub prices are likely to be a reasonable proxy for gas prices at the Canadian West Coast.

It is estimated that shipping costs from New Zealand to East Asia are roughly the same as from the Canadian West Coast to East Asia, whereas shipping costs from the US Gulf Coast to East Asia are approximately 2.5 times greater.

Overall, therefore, for the purposes of estimating a petrochemical producer’s willingness to pay for gas in New Zealand to underpin a new petrochemical production facility, it is suggested that forward Henry Hub prices would represent an appropriate ceiling. Based on the forward curve shown in Figure 10, it would appear reasonable to estimate that the price of a ten year gas deal would be approximately US$4/mmBtu. Using an implied 10 year forward exchange rate of 0.7 US$/NZ$, and converting from mmBtu to GJ, gives an estimated 10 year gas price of NZ$5.3/GJ.

When the NZ$1.3/GJ avoided shipping that was estimated earlier on page 29 is added, this gives a ceiling on a urea producer’s willingness to pay for new gas of 5.3 + 1.3 = NZ$6.6/GJ.

This is likely to be an upper bound – particularly as it is possible that petrochemical producers may apply a risk discount to the price they are willing to pay for gas from relatively small and isolated gas markets as opposed to very large gas producing areas such as North America.

This is because a small market may be heavily dependent on just one or two fields, with significantly greater ‘reserves risk’ associated with reserves turning out to be less than expected. There is little public data to enable estimation of the extent to which this reserves risk will translate into a lower willingness to pay from petrochemical producers, plus it is likely to be relatively situation-specific. However, a few statements from international petrochemical manufacturers – albeit in reference to international petrochemical developments generally, rather than New Zealand specifically – suggest that it could be significant in some situations.

Another factor which may influence the price that a urea manufacturer may be willing to pay is if, as mentioned on page 29, the existing Kapuni plant is upgraded to world efficiency standards. This will mean any subsequent new urea plant will need to sell a much greater proportion of its output to Australia or South Island. In this case, the avoided shipping cost advantage would be closer to NZ$0.7/GJ than the NZ$1.3/GJ that could be achieved from a plant which displaced the existing Kapuni facility.

Taking these two factors into account lowers the price a urea producer may be willing to pay to about NZ$4-6/GJ

3.2.4 Conclusion for new petrochemical options

In summary, it appears that new petrochemical production represents a ready avenue to commercialise significant new gas finds in New Zealand.

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26 “Canadian LNG: The race to the coast”, September 2012, Macquarie Capital Markets Canada Ltd.
27 Concept has estimated this exchange rate based on current 10 year government bond yields for New Zealand and the United States.
The most attractive initial option appears to be new urea production, due to the extent of New Zealand and Australian urea consumption and the consequent ability to avoid significant shipping costs.

It also appears that urea offers the ability to commercialise smaller quantities of gas than methanol due to the relative scale of modern new urea and methanol production facilities.

If new gas is found of a scale that is in excess of the amount that could be commercialised by a new urea production facility servicing the Australasian market, there appears to be no reason why additional petrochemical production facilities could not be developed for exporting to the wider Asia Pacific region. It is likely that the gas netback they would receive would be set based on the relative cost of producing petrochemicals in the marginal source of new petrochemical production in the world. At the moment North America can be considered to be the marginal petrochemical producer. Thus, the price of new petrochemical production using North American gas – factored by any difference in shipping costs to get to the Asian market – is likely to set the ceiling on the price a petrochemical producer would be willing to pay for gas for petrochemical production in New Zealand.

It is possible that petrochemical producers may apply a risk discount to the price they are willing to pay for gas from relatively small and isolated gas markets such as New Zealand as opposed to very large gas producing areas such as North America.
4 Gas for transport

4.1 Introduction

The transport sector is a major user of energy, accounting for 37% of energy consumed in 2013, and a significantly greater proportion of New Zealand’s non-agricultural greenhouse gas emissions. Petrol and diesel are currently the dominant energy sources. However, there is an increasing interest internationally in natural gas for use as a transport fuel.

There have been two key drivers for the development of natural gas-based fuels around the world:

- **Economic**: natural gas based fuels can be a significantly lower cost than oil-based fuels such as petrol and diesel, and can help reduce reliance on oil imports. This is particularly the case in countries where local gas prices are materially lower (on an equivalent energy basis) than oil prices.

- **Environment**: natural gas-based fuels are significantly less polluting in terms of sulphur and particulate emissions, and have therefore been promoted to address problems with human health and acid rain. Natural-gas based vehicles are not materially different in terms of carbon dioxide emissions (indeed, as set out on page 38, some gas-to-liquid fuel options result in greater greenhouse emissions), but some of the gas-to-liquid fuel options have sometimes been promoted as a stepping-stone towards biomass-derived fuels which have similar properties.

This section considers the extent to which significant amounts of gas discovered in New Zealand could be commercialised through substitution for oil-based transport fuels.

4.2 Scale of energy use in the transport sector

Figure 11 shows an estimated breakdown of consumption of oil-based fuels in New Zealand for 2013.

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In total, approximately 230 PJ of oil-based fuel was consumed in New Zealand in 2013. This is 25% more than the entire production of gas in New Zealand in 2013.

While this represents a sizeable volume in aggregate, it also represents a huge number of individual vehicles and owners. Figure 11 shows that there are over three million light transport vehicles in New Zealand. Substituting fuels would have to be implemented fairly widely for the transport sector to prove a meaningful source of new gas demand.

Figure 11 also introduces the concept of distinguishing between different types of end-use. For land transport, the key distinction is between light vehicle transport and heavy vehicles. This distinction is important because heavy vehicles require engines which can deliver a lot of power, and they are often associated with dedicated routes. Both characteristics have implications for the suitability of different types of fuel.

4.3 Description of gas-for-transport fuel alternatives

There are two broad options for utilising natural gas as a vehicle fuel:

- Fuelling a vehicle directly with natural gas, with the gas stored in the vehicle in either liquid form (i.e. LNG) or compressed form (i.e. CNG).
- Fuelling a vehicle with a liquid fuel that has been synthesised from natural gas in one form or another, particularly:
  - methanol – either alone, or blended with other traditional fuels
  - dimethyl ether (DME) – which has similarities to both LPG and diesel
  - other synthetic fuels (a.k.a. ‘synfuels’) – which captures a number of different fuels, but primarily refers to synthetic petrol or diesel.
All options have their inherent advantages and disadvantages.

The advantages of fuelling a vehicle directly with gas as either CNG or LNG are that they can generally be delivered at lower cost than petrol and diesel, given the significant historical difference between New Zealand gas prices and world oil prices on an energy equivalent basis. However, CNG and LNG necessitate engine modifications, are difficult to store, and have a low energy density, resulting in heavier and larger tank sizes, and/or a reduced vehicle range.

The advantages of most synthesised fuels are that, being liquid at ambient temperature and pressure, they are functionally more similar to conventional oil-based fuels, and more easily integrated into existing fuel distribution networks. In some cases they can be used in existing vehicles with little or no engine modification. However, the additional processing required to create the liquid fuel from the gas feedstock increases the cost of the delivered fuel, and can negate any carbon emission savings because of the losses in the transformation process.

These relative advantages and disadvantages will be the key determinants of the extent to which natural gas-based fuels are likely to displace petroleum-based fuels. This is discussed in detail in subsequent sub-sections.

However, section 4.3.1 below first provides more background description of the different types of fuels.
### 4.3.1 Characteristics of the different natural gas-based fuels

Appendix A sets out a detailed description of the properties and applications of the different gas-for-transport fuel options. This is summarised in Table 1 below.

<table>
<thead>
<tr>
<th>How it’s made</th>
<th>How it works in a vehicle</th>
<th>State of vehicle/fuel technology</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CNG</strong></td>
<td>On-site(^{29}) compression of natural gas</td>
<td>Spark-ignition engines, either factory-produced or aftermarket conversions of standard petrol or diesel vehicles. Can alternatively be used in dual-fuel vehicles with diesel, which allows for heavy-duty application. Requires a high-pressure fuel tank (~200+ bar).</td>
</tr>
<tr>
<td><strong>LNG</strong></td>
<td>Refrigeration of natural gas, either on-site, or at a central location, distributed via tanker to satellite locations.</td>
<td>Spark-ignition engines. Can be retrofitted in existing engines requiring moderate modifications, or used in a dedicated LNG engine, which allows for increased efficiency and duty. Can alternatively be used in dual-fuel vehicles(^{30}) with diesel, which allows for heavy-duty application. Requires a thermally insulated and pressurised (~8 bar) fuel tank in order to store the gas in liquid form. After around 1-2 weeks without use boil-off will require venting of some gas to maintain pressure within acceptable limits. The implications of such venting, in terms of cost, environment, and safety typically makes LNG inappropriate for mass-market, light-duty operation.</td>
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</tbody>
</table>

\(^{29}\) E.g. At a petrol station, or bus depot.

\(^{30}\) A dual-fuel vehicle is a compression-ignition engine that retains some amount of diesel to act as an ignition source for a secondary, generally more volatile, fuel. Explained further in Appendix A.
<table>
<thead>
<tr>
<th><strong>Methanol</strong></th>
<th>Converted from natural gas</th>
<th>Generally blended with petrol. Low % blends can be used in unmodified vehicles. For higher % blends, slightly modified, or dedicated engines are required. Can be used unblended in dedicated factory-produced engines, or specific dual-fuelled diesel engines. These options allow for increased efficiency and duty.</th>
<th>Well-established for light-duty vehicles. Used in motor racing for many years. Methanol blending used historically in Europe but was phased out. Methanol blending very common in some Chinese provinces, with a range of blends available. Dedicated high-methanol blend vehicles produced by a number of vehicle manufacturers – particularly those in China.</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>DME</strong></td>
<td>Converted from methanol through dehydration, or directly from natural gas</td>
<td>Can operate in existing diesel vehicles with low to moderate modifications, or dedicated engines. Either option allows for heavy duty operation. It can also operate in LPG vehicles as a blended fuel. Fuel stored in liquid form, but requires a moderately pressurised fuel tank (~5 bar). (Similar to LPG).</td>
<td>Emerging Only beginning to be utilised commercially. Some engine manufacturers have announced plans to develop dedicated DME trucking engines, and are working with DME producers to develop re-fill infrastructure along high-volume routes.</td>
</tr>
<tr>
<td><strong>Other synfuels</strong></td>
<td>Converted from natural gas or methanol/DME</td>
<td>As synthetic petrol or synthetic diesel are virtually identical to their petroleum-derived counterparts, they can be used in existing petrol or diesel vehicles with no modifications required.</td>
<td>Synthetic petrol previously produced in NZ during the 1980s, but no longer, and not produced anywhere else. Synthetic diesel produced at large scale in a handful of countries with significant natural gas volumes where LNG is not a practical option.</td>
</tr>
</tbody>
</table>
The properties of the different fuels are further summarised by Figure 12 below.

**Figure 12: Bubble diagram showing well-to-wheel carbon intensity, energy density, heavy-duty capability**\(^{31}\) and physical state of fuel\(^{32,33}\)

Figure 12 shows that:

- There is a range of suitability for heavy duty applications as indicated by the size of the bubble:
  - Petrol and LPG are not suitable because their engines produce less torque, resulting in inferior power to weight ratios compared to diesel
  - DME and synthetic diesel are equally as suitable as normal diesel
  - LNG, CNG and Methanol can be used, but with some performance drawbacks relative to diesel.

- Most gas for transport options are more greenhouse intensive than their conventional alternatives
  - Methanol and synthetic petrol are 10% and 20%, respectively, more greenhouse intensive than petrol
  - DME, LNG, and CNG are approximately 10% more greenhouse intensive than diesel, and synthetic diesel is almost 20% more greenhouse intensive

- All natural gas-based fuels are less energy dense than petrol and diesel (with the exception of the synthetic equivalents), meaning that vehicles will require larger and heavier fuel tanks, or won’t achieve the same distance between refuelling

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\(^{31}\) Based on the approximate average compression ratio, and hence torque that could be produced by engines operating exclusively on the different fuels.

\(^{32}\) Well-to-wheel carbon intensity based on US Department of Energy GREET model data. See [https://greet.es.anl.gov/](https://greet.es.anl.gov/)

\(^{33}\) Higher Heating Value (HHV). While the Lower Heating Value (LHV) is more appropriate for the energy consumed by a vehicle, the fuels are priced based on their HHV. This analysis therefore relies on HHV.
With regards to the environmental aspect of natural-gas-vehicles, Figure 12 shows that some options produce less CO\textsubscript{2} emissions than petrol, but some produce more. Those options which produce more are generally where the natural gas is synthesised into a liquid form. This is because of energy losses in the process of synthesis.

CNG and LNG options in particular result in approximately 80% less nitrogen dioxide emissions than petrol and diesel, and near to zero sulphur dioxide and particulate emissions. These significantly reduced emissions are a key driver behind China’s move to vigorously promote these types of natural gas vehicles, given the major human health problems associated with smog in many of its cities.

### 4.4 Framework for considering the potential for gas-for-transport fuel options

A key aspect of considering the potential for gas-for-transport options is considering the economics of such fuels relative to their alternatives – i.e. could natural gas-based fuels transport people or goods more cheaply than petrol and diesel?

Section 4.5 considers the supply side of this equation. i.e. how much does it cost to produce the different fuels and distribute them to end consumers?

Section 4.6 considers the vehicle cost side of this equation. i.e. even if a natural gas-based fuel can be produced and delivered more cheaply on a $/GJ basis than petrol or diesel, that advantage may be overturned if vehicles running on that fuel cost significantly more to purchase or operate.

Section 4.7 draws this analysis together to summarise which gas-for-transport options appear to show the greatest potential for New Zealand. In doing so it considers other likely drivers of transport fuel outcomes, such as range anxiety associated with new fuels.

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**Box 3: Range Anxiety**

Drivers of petrol or diesel-fuelled vehicles can travel wherever they like in New Zealand in the knowledge that if they get low on fuel, they can call in on any garage in the country to re-fill.

However, drivers of vehicles that will only run on fuels other than petrol or diesel (e.g. CNG, LNG, DME or even electricity) are currently extremely limited in their options for re-filling. Until such alternative fuels have a similar level of blanket coverage of the country, drivers of such alternative-fuelled vehicles will suffer ‘range anxiety’ – i.e. the concern that they may not be able to re-fill their vehicle if they travel farther than expected and/or to unfamiliar locations.

Such range anxiety is likely to dissuade a large number of consumers from purchasing alternative-fuelled vehicles until there is a similar level of blanket coverage of the country.

This creates a chicken and egg situation for alternative fuels. Companies will be unwilling to invest significant amounts in fuel distribution infrastructure until they have reasonable surety that there will be sufficient demand for their fuel, yet consumers will be unwilling to invest in such alternative-fuelled vehicles until there is significant fuel distribution infrastructure in place.

Such range anxiety issues are significantly reduced for dedicated commercial vehicles undertaking ‘return-to-base’ operations. i.e. they will only travel on a particular route and/or within a well prescribed range, and thus be close to a dedicated re-fuelling station. This typifies the mode of operation for vehicles such as buses, rubbish trucks and some specialised vehicles such as dairy tankers.

Dual fuel vehicles that can run on conventional petrol or diesel and an alternative fuel will also largely overcome such range anxiety issues (e.g. CNG + petrol, or Plug-in hybrid electric vehicles)
4.5 Estimating the cost ‘at the pump’ of the different fuel options

Analysis was undertaken to estimate the likely cost of delivering fuel to end consumers on a $/GJ basis.\textsuperscript{34} This analysis was undertaken on a ‘bottom-up’ basis considering the various cost components of the different fuels:

- **The fixed costs** of new fuel production facilities (being the amortised capital costs and any fixed operating costs). The $/GJ value for this cost element assumes that sufficient sales volumes can be achieved in order to spread the fixed costs over an efficient scale of sales. Appendix C sets out detailed discussion on these costs.

- **The variable operating and maintenance (O&M) costs** associated with producing the fuel.

- **The distribution and retail costs** associated with getting the fuel to the end consumer. Appendix C sets out detailed discussion on these costs but key points to note are that:
  - Both synfuels and low-% methanol blends could utilise existing distribution infrastructure at minimal additional cost – however, the lower MJ/litre energy density of methanol will increase the $/GJ distribution costs.
  - The need for cryogenic temperatures makes distributing LNG a high-cost activity. Similarly, the need to maintain DME under pressure makes the costs of distribution quite high. However, it may be able to benefit from existing LPG distribution infrastructure. CNG requires very high pressure, but compression is performed on site using gas supplied from the pipeline network, so production and distribution are essentially one and the same.
  - High-% methanol blends would require new storage and pumping facilities at existing forecourts, but these would be similar in cost to those required for conventional fuels.

- **The wholesale cost of the raw fuel.** For gas the central assumption is NZ$6/GJ\textsuperscript{35}, whereas for petrol and diesel it assumes US$75/bbl and a 0.70 USD/NZD long-term exchange rate. A key aspect of the wholesale fuel cost of the different gas-based fuel options is the energy conversion efficiency from gas to fuel for those options where the gas is converted into another chemical form. For example, the energy content of methanol is only 60% of that of natural gas\textsuperscript{36}. This contrasts with CNG which has not been converted and thus has 100% of the energy content of natural gas. Accordingly the wholesale fuel cost component of CNG is only 60% of methanol.

- **Any carbon costs**, based on the tCO\textsubscript{2}/GJ emissions intensity of each fuel, and the price of CO\textsubscript{2}. (Central assumption = NZ$25/tCO\textsubscript{2})

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\textsuperscript{34} Although petrol and diesel are currently sold on a $/litre basis, the different energy densities of the different fuels makes $/litre an inappropriate metric to compare the cost of the different fuels.

\textsuperscript{35} This is the wholesale cost of gas (i.e. excluding any transmission costs) for a flat profile.

\textsuperscript{36} i.e. the energy density (measure in MJ/kg) of methanol is only 60% of the energy density of natural gas.
Table 2 summarises the production and distribution investment requirements for the different fuels

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>LNG</th>
<th>CNG</th>
<th>Methanol</th>
<th>Methanol blends</th>
<th>DME</th>
<th>Synfuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production</td>
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<td>Distribution</td>
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Road taxes and GST are excluded from the analysis because, although some fuels may currently have lower tax advantages to end consumers, such ‘artificial’ price advantages are a result of government policy that could change in the future – particularly if there is a significant amount of uptake of those fuels.

For petrol and diesel, although distribution and retail and carbon costs are separately identified, the costs of shipping and refining have been incorporated into a single ‘product cost’ line item. i.e. this is the cost of refined petrol or diesel at the refinery gate.

Separate analyses were undertaken for heavy-duty and light vehicle transport requirements given the significant differences between the two. For heavy-duty applications, distinction was also made between:

- ‘return-to-base’ applications – i.e. where dedicated re-fuelling infrastructure can be developed to fuel vehicles that operate distinct routes (e.g. buses, rubbish trucks, and some specialised transport options such as dairy tankers and logging trucks)
- ‘widespread distribution’ where it is assumed that the fuel will need to be distributed via the existing network of service stations.

### 4.5.1 Heavy-duty applications

The results of the analysis is shown in Figure 13, which gives an estimate of the fuel cost at the pump for each of the potential fuel options, excluding all taxes. Petrol and LPG have been excluded from the analysis because their fuel characteristics make them not suited to heavy duty applications.

For some options to be efficient, they would probably need to be rolled out progressively. In this regard, they would likely first be adopted by return-to-base applications. Return-to-base applications often achieve the scale required with a smaller number of vehicles because they are high-use consumers, can bypass range anxiety issues, and can be served by a single custom-sized filling station, thereby avoiding the need for widespread infrastructure and ensuring a predictable number of returning vehicles. For this reason, the analysis has assumed a return-to-base set-up for LNG, CNG and DME. These assume micro-scale production facilities at the base, rather than the macro-scale facilities that have been traditionally associated with LNG and DME.

Synfuels will also need to be produced using smaller-scale production facilities, however, even smaller-scale production facilities for synfuels are significant in size, requiring the use of widespread distribution to achieve sufficient sales volumes. The production facilities for these fuels are discussed in more detail in Appendix A.

As discussed in Appendix A, methanol has a significant advantage because it is already produced here, and therefore no new investment in a manufacturing facility is required. The methanol option
considered for heavy duty applications is pure methanol – i.e. not a methanol blend. This is because methanol blending is only feasible with petrol (not diesel), which practically limits its use to only light duty applications. Methanol could be used in a dual-fuel heavy-duty vehicle with diesel, but in that case, the fuels would not be blended together.

*Figure 13: Estimated cost per GJ for existing and potential fuel options for heavy duty applications (excluding taxes)*

The analysis shown in Figure 13 suggests:

- A return-to-base CNG operation provides the lowest-cost fuel option by some margin. It benefits from moderate infrastructure costs, relatively low operating costs, and the advantages that would arise from having a custom-sized filling-station, serving a fleet of high-mileage vehicles such as buses or rubbish trucks.

- LNG and DME fuel costs also appear competitive compared to diesel for a return-to-base operation. However, it should be noted that these prices assume the efficient scale for investment is achieved, which would require around 100-300 heavy duty vehicles travelling around 100,000 km/year each. There are likely only a few parties that would be able to meet this scale on their own. One potential example would be a dedicated fleet of trucks servicing large dairy factories.

- Methanol could present a competitive alternative to diesel if distributed widely. However, widespread roll-out of distribution infrastructure would be practically very difficult to achieve, as the customer base needs to be in place to support each additional fuelling station. The fixed costs for pure methanol assume unloading facilities are required at the methanol production plant, and an additional forecourt pump (at similar cost as for petrol) for every 1,000 vehicles. It is interesting to note that the price of methanol is strongly influenced by the distribution and retail costs. This is because of its much lower energy density compared to diesel (around 18 MJ/l HHV compared to 37 MJ/l). Distribution and
retail costs are assumed to be largely driven by weight or volume, and are hence considered to be approximately double on an energy equivalent basis.

- It may be possible to produce synthetic diesel competitively at the assumed crude oil and gas prices.

### 4.5.2 Light duty applications

The same analysis has been performed for light duty applications. This is shown in Figure 14. The costs for synfuels, diesel and methanol are the same as those in Figure 13.

LNG has been excluded because, as discussed in Table 1, boil-off issues make it an inappropriate fuel for mass-market applications. DME is also excluded for light-duty applications, purely because there is currently no precedent for light-duty DME engines, and no suggestion of development in this area.

Electric vehicles have been included because natural gas-based fuels will be competing with them for a place in the light vehicle market. This is discussed further in Appendix E. The assumed electricity price for re-charging an electric vehicle is 12 c/kWh (incl. GST). This assumes the EV is predominantly re-charged overnight.

**Figure 14: Estimated cost per GJ for existing and potential fuel options for light duty applications (excluding taxes)**

The analysis shown in Figure 14 suggests:

- Electricity is likely to be the most competitively priced fuel option, followed by CNG. Section 4.6 discusses the extent to which this delivered fuel price advantage may be offset by higher vehicle costs. For CNG, it is assumed that sufficient scale is achieved, in terms of the number of CNG vehicles over which to spread the investment in re-fuelling infrastructure at the forecourt. This is discussed in detail in Appendix C which demonstrates that this is likely to
be of the order of 1,000 vehicles per re-fuelling station. If significantly fewer vehicles convert to CNG, the fixed costs of CNG will be much greater.

- Methanol to be used for blending is a lower cost option than petrol for the central assumptions of gas and oil prices. It will require an extra cost to ship the methanol to Marsden for blending, but can then use the existing fuel distribution infrastructure. The cost of using this existing fuel distribution infrastructure is assumed to be roughly double that of petrol because methanol has half the energy density of petrol and diesel, and distribution and retail costs are assumed to be largely driven by weight or volume.

- Higher-% methanol blends could also be a cost-competitive fuel option. The analysis assumes that there will need to be some investment in specific distribution infrastructure (i.e. unloading facilities at Methanex’s plant, and storage tanks and blending infrastructure at re-fuelling stations), and that an efficient scale is achieved. However, it would avoid the need to ship the methanol to Marsden to be blended.

- Synthetic diesel could be produced slightly cheaper than normal diesel at current oil and gas prices. Section 4.5.3 below discusses how sensitive this cost advantage is to oil and gas price differentials.

- The cost advantage that LPG currently has at the pump is an artifice of the lower taxes charged relative to petrol and diesel, as the analysis shows that the underlying costs are higher.

### 4.5.3 Sensitivity to oil and gas price changes

One of the key drivers for considering opportunities to utilise natural gas in the transport sector has been the considerable differential that, until recently, existed between oil and gas prices. This difference can provide an opportunity for arbitrage.

However, as the recent collapse in oil prices has demonstrated, investing to take advantage of such arbitrage is vulnerable to significant changes in the relative prices of the two commodities. This is particularly true where significant capital investment is required, either by producers or consumers, and the subsequent risk of stranding assets is high.

Based on Figure 13, synthetic diesel would be most at risk from changes in oil or gas prices, because of the significant capital investment required to develop synthetic diesel, and because of the 56% energy conversion efficiency associated with gas to synthetic diesel production.

Methanol is the next most exposed option to oil and gas price changes due to its 60% energy conversion efficiency and high distribution costs.

In contrast, CNG with its low capital investment and 100% energy conversion efficiency seems little exposed to the risk of oil and gas price changes.

To demonstrate this risk, Figure 15 shows the maximum gas price that would allow synthetic diesel and methanol to be competitive, under a range of oil prices and exchange rates.
Figure 15 highlights that synfuels require a lower gas price to be competitive than methanol does, across the range of oil prices and exchange rates. For example:

- At an oil price of $US100/bbl and exchange rate of 0.7 USD/NZD, synfuels could withstand gas prices up to NZ$9.5/GJ, while methanol could withstand prices up to NZ$13.5/GJ.

- At current gas prices of around $6.0/GJ, and an exchange rate of 0.75 USD/NZD, methanol would be out of the money at an oil price of less than $US52/bbl. However, synfuels would be out of the money at oil prices below $US75/bbl.

Production of synfuels in New Zealand would require capital investment of around $US 100-150 million (for a comparatively small-scale facility relative to those currently operating internationally). Given the relatively narrow band of oil and gas prices and exchange rates within which synfuels would be able to compete against conventional diesel, this would represent a significant investment risk.

Because there is no need to invest in new methanol production facilities in New Zealand, methanol is likely to remain competitive against conventional petrol for a significant range of future oil and gas prices and exchange rates. Further, because there is a low need for investment capital – particularly for low-level blending – there is a much lower penalty to it becoming uncompetitive. If oil prices dropped significantly, methanol blending could be halted for some period and then resumed when prices became more favourable.

As LNG, DME and CNG have higher energy conversion efficiencies than methanol, they could be expected to withstand greater price movements. Their competitive advantage is therefore likely to be relatively insensitive to changes in oil and gas prices, and exchange rates.

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37 As discussed in Appendix A, these small scale facilities are beginning to be developed overseas.
Table 3: Summary of natural gas-based fuels’ ability to remain competitive against conventional fuels with changes in the price of oil and gas, and exchange rate movements

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>LNG</th>
<th>CNG</th>
<th>Methanol</th>
<th>Methanol blends</th>
<th>DME</th>
<th>Synfuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sustainable fuel price advantage</td>
<td></td>
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</tbody>
</table>

4.6 Estimating the vehicle costs of the different fuel options

While it appears that natural gas-based fuels could be delivered to consumers at prices competitive with conventional fuels, the displacement of existing fuels with natural gas based alternatives will depend on the degree to which consumer investment in ‘special’ vehicles is required.

Displacement is much more likely where the investment cost and effort for the consumer is low, including with regard to:

- any price premium for vehicles, driven by the need for different engine and fuel-system requirements
- the ability to access appropriate vehicles and on-sell them as required
- any trade-offs in terms of range, performance, utility or safety
- the need for consumers to change their behaviour.

These issues can affect both the ultimate level of uptake, and the rate at which it occurs. The latter factor is important because even if the economics are viable, it may be very difficult to achieve sufficient scale because the rate of uptake is constrained by vehicle replacement cycles.

The issues are discussed in depth in Appendix C. The different engine and fuel system requirements are discussed in Appendix A.

Modifying a conventional light-duty vehicle to operate on CNG reportedly costs around $3,000. Using the fuel-price advantage of CNG for light-duty vehicles shown in Figure 14, and assuming: a 10% discount rate; that a consumer drives 10,000 km/year; and that vehicle efficiency is not impacted; it would take around 8.5 years to make a return break-even on this investment.

This suggests that a modest price premium for a vehicle will take a relatively long time for a mass-market consumer to recoup, even for the most price-competitive natural gas-based fuel option. This is a key issue currently dictating the economics of electric vehicles.

For many consumers, paying an up-front capital premium will in itself be enough of a disincentive to invest. However, some of the most significant investment barriers for consumers are subjective or ‘soft’ barriers like range anxiety, which are very difficult to quantify.

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38 10,000 km/year is close to being the median distance travelled by light passenger vehicles in New Zealand.

39 For example, if a vehicle travels significantly further than 10,000 km/yr, the payback period for higher capital cost vehicles is less. However, it is likely that such high distance vehicles may suffer more from range anxiety, and uptake will be impacted unless there is widespread re-fuelling coverage across the country.
In this regard:

- Synfuels will be the natural gas-based fuel that will be most easily accepted by consumers, as it is functionally identical to conventional diesel, and there will be no range anxiety issues.

- Low-% methanol blends will also avoid most barriers to consumer uptake as there are similarly no range anxiety issues, but is complicated by the need for vehicle manufacturers to provide warranties for the use of methanol blends – discussed more in section 4.7.2.

- Higher-% methanol blends have some barriers to investment for light-duty applications (larger barriers for heavy-duty). However, if fuel-flex vehicles were made available in New Zealand with no price premium (as is the case in other markets), then some uptake could occur. However, penetration of new vehicles in the market may be slow because of consumer uncertainty as to the extent to which this technology will be a long-term winner compared to technologies such as electric vehicles.

- LNG and DME have significant barriers to uptake, particularly given the current state of these technologies. Because of the upfront price premium for appropriate vehicles, uptake of these technologies in the near term will require a commercial consumer who has a relatively long investment horizon, and who finds particular value in fuel cost savings. This is similarly true for CNG.

- CNG is likely to be the least-preferred option from a consumer utility perspective, as it has particularly low energy density and hence reduced range, and the heavy, high-pressure tanks take up significant space and may have some minor additional compliance requirements in response to safety implications.

In addition to barriers associated with the different natural gas-based technologies themselves, there is also the need to consider the impact of competition from other technologies. In particular, electric vehicles are likely to begin competing strongly in the light-duty vehicle market within the next decade. This will affect the potential for uptake of light-duty CNG and high-% methanol blends in particular.

As is discussed in depth in Appendix E, although the capital cost premium for electric vehicles is currently higher than gas-based vehicles, the rate of cost reduction for electric vehicles is significant. Further, electric vehicles enjoy a number of other significant advantages over CNG and high-% methanol blends:

- As is illustrated in Figure 14, electricity is a considerably cheaper fuel;

- electric vehicles generally enjoy lower maintenance costs because of their simpler drive trains;

- plug-in hybrid electric vehicles (PHEVs) and range extended electric vehicles (REEVs) do not suffer from the range anxiety issues that CNG and high-% methanol blends have. As such PHEVs and REEVs are likely to be ‘bridging’ technologies to mass uptake of all-electric battery electric vehicles (BEVs).

Accordingly, electric vehicles appear likely to be more cost-effective in the long-run for light vehicles than CNG and higher-% methanol blends. There would therefore appear to be significant stranding risk associated with investing in the infrastructure required for CNG and higher-% methanol blends.

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40 This is as much a function of the significantly greater energy conversion efficiency of electric motors compared to internal combustion engines (with electric motors being approximately 3 times more efficient) as it is relating to the delivered price of the two fuels on a $ per unit of energy basis.
However, as further discussed in Appendix E, electric vehicles may be less prospective for heavy duty applications.

A summary of the barriers to consumer uptake of natural gas-based fuels is given in Table 4.

**Table 4: Summary of barriers affecting consumer uptake of natural gas-based fuel options**

<table>
<thead>
<tr>
<th></th>
<th>High barrier</th>
<th>Moderate barrier</th>
<th>Low/no barrier</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Heavy Duty Vehicles</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vehicle price premium</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Availability of vehicles</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Range/performance/utility/safety</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Behavioural changes</td>
<td>Yellow</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Competition with other options</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td><strong>Light Duty Vehicles</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Vehicle price premium</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Availability of vehicles</td>
<td>Yellow</td>
<td>Red</td>
<td>Yellow</td>
</tr>
<tr>
<td>Range/performance/utility/safety</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Behavioural changes</td>
<td>Yellow</td>
<td>Yellow</td>
<td>Green</td>
</tr>
<tr>
<td>Competition with other options</td>
<td>Red</td>
<td>Yellow</td>
<td>Green</td>
</tr>
</tbody>
</table>

4.7 Summary of the potential of the different gas-for-transport technologies in New Zealand

There are a large number of permutations between the different fuel options and transport markets. Some of the options may hold some promise, while others are clearly less attractive.

4.7.1 Options which do not appear promising in the New Zealand context

Many gas-for-transport options can be ruled out qualitatively due to the state of the technology, difficulties in establishing it in a small market, or obvious economic barriers. Specifically:

- Some technologies are inappropriate for some uses. For example:
  - LNG is not appropriate for mass-market, light-duty vehicles because of the likelihood of fuel-tank boil-off issues, with associated safety, cost and environmental issues.
  - The energy density of CNG makes it impractical for marine use.
  - Synthetic petrol (as opposed to synthetic diesel) has no current international precedent. It was previously manufactured in New Zealand, and the process used has since been improved upon. However, it was not a competitively priced option, and was eventually abandoned.

- Some of the fuels are at an early stage of development, and the availability of the vehicle technology is limited. For example:
There appears to be little development activity in alternative-fuelled agricultural vehicles, with the exception of bio-diesel, or potentially bio-ethanol vehicles.

DME vehicles are at an early stage of development, and bespoke vehicles are not yet available. However, Volvo has suggested that of seven alternative fuel options it investigated, it has prioritised DME as a preferred development option. Interest appears to be exclusive to heavy duty vehicles at this stage. The advantages of DME vehicles are that they utilise similar technology to existing diesel engines and have comparable performance, while avoiding the need for expensive exhaust treatment. They also require simpler tank technology than LNG or CNG, and could be suitable for both short and long-haul trucking. While it is unlikely that New Zealand could be a technology-leader for a DME application given our relatively small scale, use of this option may become a more feasible in the future if the technology proliferates overseas.

Some of the fuels would require significant investment with risk of stranding. For example:

- At first glance, synthetic diesel appears to be a promising option to commercialise a significant gas find. It would support an existing consumer base, and requires no additional investment in downstream infrastructure. However, as illustrated in Figure 15 on page 45, any investment in the production facilities is open to significant stranding risk from a drop in oil prices, or increase in gas prices, which is likely to deter any would-be investors. Indeed, at current world oil prices, it is likely that such an investment would be uneconomic.

- Methanol may be an option for marine transport. One possible candidate for such an option is the Cook Strait ferries, whose existing ships could be retrofitted for methanol use. However, it is not clear whether the volume of fuel for the Interislander or Bluebridge would justify the cost of conversion for the ferries and the development of fuelling infrastructure at either or both of Wellington and Picton. This would carry an investment risk, as the ferry owners would be concerned about possible movements in world methanol and gas prices, which may cause methanol production in New Zealand to cease altogether (as came close to happening in 2005 with the mothballing of most of Methanex’s capacity). Investment risks may also arise because of the need to be able to accommodate stand-in ships if there are mechanical problems. Further, whereas overseas the key driver for the move to methanol fuels has been a desire to reduce sulphur emissions, there is not the same focus in New Zealand.

Some technologies require a degree of consumer buy-in that evidence suggests will not be overcome easily. For example:

- CNG for light vehicles is popular in a number of overseas markets, and at first glance, the fuel cost advantages seem compelling. However, conversion costs and effort, maintenance costs, and range anxiety from limited refuelling infrastructure will likely result in it being an unpopular option amongst drivers. New Zealand already has experience with CNG vehicles (discussed further in Appendix A). At the height of its use in the mid-1980s, CNG vehicles consumed 5.85 PJ of gas per year. However, their popularity declined after government subsidies were withdrawn, and they have now largely been phased out, with much of the refuelling infrastructure removed. LPG serves as another example of an alternative fuel for which demand has been reducing over time despite fuel-price advantages, and which is now largely confined to use by taxis. Furthermore, CNG for light vehicles appears unlikely to be able to compete against electric vehicles whose capital costs are coming down, and which additionally promise: cheaper fuel,
lower maintenance costs, and reduced range anxiety issues compared to CNG for EVs such as PHEVs and REEVs.

- At least one party has reportedly considered using LNG for factories whose trucks operate around the clock on a return-to-base basis. However, they have not sought to take the option forward at this stage. It is understood that, while there were likely fuel cost advantages, the option was disadvantaged by the difficulty involved in acquiring appropriate LNG tractors in New Zealand, exacerbated by:
  - the absence of a secondary-market for the vehicles when they were retired, resulting in high depreciation and disposal costs (noting that the life of a tractor for such round-the-clock operations is approximately 2 years)
  - considerable costs in terms of vehicle maintenance, due to moving to a new manufacturer and new technology for which expertise is limited.

- Some fuels require scale that would be challenging to achieve with coordinated decisions. For example, LNG or DME would probably require the equivalent of around 100 heavy duty vehicles for fixed costs to be recovered, while remaining competitive with conventional options. It is unlikely that use solely by marine or rail would provide the scale necessary to justify the investment in infrastructure. However, investment may be more appealing if different transport options were able to coordinate their activities to collectively achieve the necessary scale. For example, if marine, transit buses and trucking companies were all able to utilise a single return-to-base LNG facility or point-to-point set-up (or similar), this would likely improve the feasibility of such a development.

These conclusions are summarised by Table 5. This highlights that there are no “easy options”. However, there are some options which may have development potential, if some of the hurdles impacting them can be overcome. These are discussed in turn.

Table 5: Summary of potential development opportunities

<table>
<thead>
<tr>
<th>Fuel type</th>
<th>LNG</th>
<th>CNG</th>
<th>Methanol</th>
<th>DME</th>
<th>Synfuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transport type</td>
<td>Light vehicles</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
</tr>
<tr>
<td></td>
<td>Heavy vehicles</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
</tr>
<tr>
<td></td>
<td>Buses</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
</tr>
<tr>
<td></td>
<td>Marine</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
</tr>
<tr>
<td></td>
<td>Rail</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
</tr>
<tr>
<td></td>
<td>Agriculture vehicles</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
<td>✅</td>
</tr>
</tbody>
</table>
4.7.2 Methanol fuel blending presents the most immediate opportunity

Methanol blending appears to be an option that could have net benefits to NZ. Methanol blending, if done at low levels, would have few barriers to implementation because:

- methanol is already produced in NZ, so there is a minimal need for supply-side investment
- it could be distributed using existing infrastructure, so there is minimal need to invest in distribution
- it could be implemented without the need for investment from consumers
- it would have fuel cost advantages
- it would reduce New Zealand’s dependency on overseas oil for its transport needs, improving its fuel security.

Introducing a 15% methanol blend to New Zealand’s petrol, if it had widespread uptake, would consume about 25 PJ of gas a year. This is slightly above the consumption of Methanex’s Waitara Valley methanol train. At current oil and gas prices, blending all of New Zealand’s petrol with 15% Methanol would deliver fuel cost savings to New Zealand of approximately $150m per year.

As set out in more detail in Appendix B, international markets have experience with methanol blending that New Zealand could utilise in implementing it here. Both the USA and European Union allow methanol blending at low levels (up to 5% in USA and 3% in Europe), although neither has implemented it to any significant degree – in large part because of the issues relating to vehicle warranties. In the USA, blending with 10% ethanol is already common, which introduces practical limitations to additionally blending in methanol.

China is the largest user of methanol blends in the world, with a range of percent-blends available in various provinces. The Shanxi Province in China allows up to 15% blending, which is being considered for a national program.

However, although methanol blends could deliver considerable fuel cost savings to New Zealand, the key issue for whether it is likely to be practicable for New Zealand is whether vehicle manufacturers will issue warranties for standard vehicles using low-% methanol blends. A few vehicle manufacturers provide a warranty for use of fuel with some amount – usually 10% - of ethanol. For example, BMW appears to allow (or has allowed) blending with up to 3% methanol + co-solvents (the European Union allowance) under warranty. However, all other vehicles specifically recommend against use of fuels with methanol, and warranties are void if they are used.

It is generally suggested that modern vehicles, having sophisticated fuel injection systems to ensure consistent fuel injection, and improved corrosion-inhibitors, have some degree of flexibility regarding the amount of alcohol blended into fuels. This has supported China’s adoption of 15% methanol blends, and blends of up to 25% by volume of ethanol in Brazil, with little impact on drivability or vehicle performance degradation. However, vehicle manufacturers have successfully opposed proposed changes to methanol allowances in the USA in the past. Vehicle manufacturers therefore represent the biggest impediment to methanol blending.

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42 As illustrated in Figure 11 on page 2 New Zealand consumes about 100 PJ of petrol a year. Given the 60% conversion efficiency of turning gas into methanol, 15% of this 100 PJ being supplied by methanol would equate to 15 ÷ 60% = 25 PJ of gas a year.
44 See http://www.ethanolrfa.org/page/-/rfa-association-site/Industry%20Resources/RFA%20Auto%20Manufacturer%20Fuel%20Recommendations%202012%202013%202014%202013.10.30.pdf?nocdn=1
The willingness of vehicle manufacturers to warrant 10% ethanol blends is a reflection of the routine blending of bio- ethanol with petrol in the USA. Currently there is little incentive for them to do the same for methanol blends. Therefore, overseas initiatives to adopt methanol blending are likely to be critical to NZ’s ability to do the same.

However, it cannot be assumed that this will happen. The main driver for fuel blending in Europe and the USA is to decrease greenhouse gas emissions, through blending ethanol produced from biomass. However, methanol produced from natural gas does not have any greenhouse gas advantages. Indeed, as illustrated in Figure 12 on page 38, compared with petrol it emits slightly more CO₂e per GJ of useful energy.

Advances on the warranty issue may therefore rely on China. If Chinese manufactured vehicles start to take market share from other vehicle manufacturers in China because they have warranties for methanol blends, this may provide a spur for the other manufacturers to also issue warranties.

The other aspect to appreciate for methanol blends as a transport fuel is that, although it could deliver considerable transport fuel cost savings for New Zealand, it would not result in any more gas being consumed in New Zealand. This is because the methanol would in all likelihood come from existing production facilities, and all that would happen is that methanol would be diverted to a domestic New Zealand market rather than being shipped overseas.

Because the amount of methanol required for the New Zealand transport market would likely be less than the output of one of Methanex’s three trains, it would not alter the economics of building any new trains. This is because the output from a new train would be entirely for export for the international methanol market.

The only potential impact of using methanol as a transport fuel on New Zealand gas volumes would be if world methanol prices fell significantly resulting in Methanex mothballing or closing its New Zealand production facilities. Although it would not alter the economics of closing the ‘first’ two trains, it could alter the economics of Methanex closing the ‘last’ train, and may result in Methanex keeping the last train open when it might otherwise have closed it.

New Zealand could also feasibly begin to adopt higher percent blends. However, this route would be inherently slower and more expensive. The primary factor influencing the rate of uptake would be the availability of fuel-flex vehicles. Fuel flex vehicles can run on a wide variety of methanol blends, including straight petrol, but are generally optimised for an 85% methanol blend. Fuel-flex vehicles are likely to become more widespread, and are already relatively common in the USA (although for use with ethanol). However, uptake of any new vehicles will be slow, given expected rates of replacement, and the high volume of vehicles bought and sold second hand. They will also be subject to competition from electric cars and other alternatives. As such, higher-% methanol blends do not appear to be a prospective option for New Zealand.

4.7.3 CNG buses or return-to-base heavy vehicles appear prospective

For the reasons set out above, it appears unlikely that CNG would become a popular option for mass-market, light-duty vehicles again. New Zealand’s experience with both CNG and LPG for light vehicles supports this view, and the advancement of electric vehicles will likely reduce this probability even further.

However, it is not immediately clear what factors may be preventing interest in CNG return-to-base heavy vehicles, given the apparent potential for fuel price advantages, as shown by Figure 13. Suggestions are that CNG is typically 20-40% cheaper than diesel to run overall.46

CNG vehicles are a mature technology, with significant uptake of CNG for municipal buses and refuse vehicles in some overseas markets. New Zealand, having had previous experience with CNG, retains much of the expertise to implement such systems. Indeed, there are New Zealand companies that manufacture CNG refuelling technology and export their products overseas.

The most likely impediments to uptake are therefore likely to be ‘soft’ barriers that could be overcome with some encouragement, targeted at the right consumer. For example:

- While mass-market adoption faltered without the generous government subsidies that supported early interest, conversion and set-up costs would be expected to be less of a barrier for commercial return-to-base operations such as buses or refuse vehicles.
- Range anxiety may be one of the impediments. However, for municipal buses and refuse vehicles that return regularly to the same place, this should not be a concern.
- The reduced engine performance of CNG engines may also concern some. International experience suggests that, while economic benefits are possible for heavy-duty vehicles, some consumers have struggled to realise these due to poor engine performance. The primary benefits have hence been environmental (particularly reduced particulate emissions) and noise benefits. However, CNG heavy-vehicles continue to be advanced and developed. Methane dual-fuel vehicles are another of Volvo’s preferred development options.\(^{47}\)

Despite this promise for these return-to-base vehicles, it should be appreciated that any realistic uptake of CNG would have a relatively limited impact on the gas market. To give an indication of the scale involved, if all buses in New Zealand, and 5% of diesel use by heavy duty vehicles was replaced with CNG, this would represent around 5 PJ of natural gas annually. This compares with the 20 to 100 PJ/yr scale that could be required to commercialise a significant new gas field.

4.7.4 LNG or DME for heavy truck applications could be viable in the future

LNG or DME appear to be options with potential for the future for niche parts of the heavy-duty industry, where the consumer barriers can be overcome. With the advent of small-scale liquefaction and DME production facilities, the development of these fuels for return-to-base or point-to-point applications becomes a feasible future option for New Zealand.

As discussed earlier, at least one major industrial company with significant return-to-base trucking operations has reportedly considered using LNG, but did not seek to take the option forward at this stage, because of the difficulties in acquiring, maintaining and on-selling appropriate LNG-fuelled vehicles.

Their decision therefore suggests that LNG is not yet feasible for NZ. However, based on the growth of such technology overseas, it is possible that LNG or DME fuelled trucking could emerge in New Zealand within a decade.

In this regard, the development of LNG for transport is more advanced, with dedicated re-fuelling facilities established along high-volume freight routes in Australia, Europe and the USA. In many instances, these are supported primarily by large-scale LNG production facilities, rather than the micro-scale facilities that would be likely here.

That said, the scale of gas consumption from such applications is likely to be relatively small compared to the scale of gas consumption required to commercialise new gas fields. For example, if micro-scale LNG or DME facilities were developed here, capable of producing 10,000 tonnes per annum, and were operated at capacity, this would represent consumption of around 0.5 PJ of natural gas per annum.

5 New power generation

The September 2014 Long Term Gas Supply and Demand Scenarios study\(^{48}\) identified that the power generation sector has historically played an important role in commercialising new gas discoveries in New Zealand. In the 1980s this was through the development of the 1,000 MW Huntly station using steam turbines, and in the 1990’s and early 2000’s this was via the development of a number of higher-efficiency combined-cycle gas turbines (CCGTs).

The October ‘14 study also presented considerable new analysis (including a downloadable spreadsheet tool) on the issues relating to the future for gas-fired power generation in New Zealand. As such, this current study does not repeat the detail of the October ‘14 study, but merely highlights the key conclusions as they pertain to the potential for any new gas discoveries to be commercialised via a new gas-fired power station.

\textit{Competition from new renewables}

The first of these issues is that a potential new CCGT will be competing against potential new renewable projects to meet any growth in baseload demand. In particular, it will be competing against potential geothermal and wind projects.

The economics of these competing renewable technologies will dictate the maximum breakeven gas price which a CCGT could incur before it becomes uncompetitive. On a global scale, New Zealand enjoys some of the lowest cost options for these renewables due to our relatively large and accessible geothermal fields in the central North Island, and our strong and consistent winds.

This translates into long-run marginal costs for many of these options of between $75-85/MWh for geothermal and $85-100/MWh for wind\(^{49}\). Given this ‘target’ LRMC which a CCGT must beat, it is possible to work out the maximum (or ‘breakeven’) gas price which the CCGT would be able to sustain.

This is complicated by the cost of \(\text{CO}_2\) emissions. As \(\text{CO}_2\) prices rise, the breakeven gas price for a CCGT to be competitive against renewables will fall. The rate of decline of breakeven gas price as \(\text{CO}_2\) prices rise will be lower for comparing CCGTs against geothermal technologies (which themselves emit almost 40\% of the \(\text{CO}_2\) of a CCGT), than for comparison against wind technologies (which emit no \(\text{CO}_2\)).

Figure 16 below shows how this breakeven gas price for a new CCGT will vary when competing against renewable technologies with different LRMCs, and for different \(\text{CO}_2\) prices.

\(^{48}\) This report can be found here: http://gasindustry.co.nz/work-programmes/gas-transmission-investment-programme/supply-and-demand/long-term-gas-supply-and-demand-scenarios/

\(^{49}\) The range is because some renewable projects have different costs than others, due to variances in the quality of the wind or geothermal resource, and variances in the civil engineering costs required to build the project. (e.g. a wind site located in a remote mountainous location will cost more to build than one located near existing roads). Further, variances in the NZ$ exchange rate will impact on the cost of new renewables (much of whose costs consist of the purchase of overseas capital).
Currently effective CO₂ prices faced by New Zealand power stations are very low (<NZ$2/tCO₂).

Looking forward, there is significant uncertainty as to future CO₂ prices. This is because, unlike other commodities, the key drivers are not so much the fundamentals of supply and demand, but rather the outcome of international political negotiations.

As an illustration of the scale of this uncertainty, one commentator has recently pointed to Treasury analysis that suggests CO₂ prices are likely to be somewhere between $10 and $165/tCO₂ during the 2020s.⁵⁰

Given this uncertainty regarding future CO₂ prices, the breakeven gas price which a new CCGT would require in order to be competitive with new renewables is likely to be between NZ$3-6/GJ.

Further, if a powerstation were to take on reserves uncertainty (i.e. the risk that reserves for a particular field turn out to be less than expected), it is likely that it would require a discounted gas price compared with a situation where the gas supplier took on this reserves risk.

**Electricity demand growth**

The other factor to consider in relation to the potential for new gas-fired generation is whether there is likely to be demand for such generation. Given New Zealand’s renewables-dominated electricity system, supplemented largely by existing CCGTs, a new CCGT would only really be able to be built to meet any growth in electricity demand, rather than displace existing generators.

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However, as the October 2014 report highlighted, the New Zealand electricity market has seen a reduction in electricity demand over recent years, due to a variety of factors including:

- Reduction in demand from the Tiwai aluminium smelter due to low world aluminium prices and the high NZ$ dollar;
- The closure of one of the Norske Skog Tasman paper mills;
- The Christchurch earthquake;
- An economic downturn following the GFC; and
- Increased energy efficiency of appliances and buildings.

It is likely that demand growth will return again at some point in the future; however, the extent of such growth is uncertain. There seems little prospect of any new energy-intensive heavy industrial demand such as an aluminium smelter, steel plant, or pulp and paper mill. It is possible that non-heavy industrial demand could return to the rates of growth seen prior to the GFC (which were approximately 2.2% per annum). However, it is possible that further energy efficiency impacts, and factors such as rapid PV uptake, may mean that the rates of grid electricity demand growth could be less than seen historically. Conversely, the emergence of plug-in electric vehicles could result in a significant increase in demand growth above, what has been seen previously.

The other factor to consider is that some of the demand growth will be growth in ‘peaky’ demand – i.e. demand at times of the morning and evening peaks, and during winter months. The capital intensive nature of CCGTs (and other renewable generators) means they are not cost-effective options for meeting this peaky demand growth. Instead, less capital intensive options such as OCGTs are more cost-effective. Based on historical data, only 70% of demand growth could be considered baseload – and thus potentially suitable to be met by a new CCGT.

Taking all of these factors together, if non-heavy industrial demand growth were to revert to 2.2% per annum, and only 70% of this could be considered to be baseload, this would result in baseload demand growth of approximately 540 GWh/yr, or 68 MW baseload.

This compares with a modern CCGT size of approximately 350 MW which, if operated at 85% capacity factor, would generate approximately 2,600 GWh/yr – and consume approximately 19 PJ/yr.

In other words, annual baseload demand growth in this scenario would only be approximately 20% of the output of a new CCGT. This will make it a lot harder for a new CCGT to ‘fit in’ to meet demand growth without causing a period of surplus generation capacity (and consequently lower electricity prices) when it is first built.

This compares with geothermal and wind plant which are much more readily built in smaller increments, and thus can be better sized to meet underlying demand growth.

The initial electricity price supressing effects of a relatively large new power station being built will tend to make the economics of new CCGTs less favourable than geothermal and wind projects which can be built in smaller increments. Accordingly, the break-even gas prices set out in Figure 16 will tend to be even lower.

In summary, it is possible that a new CCGT could be built if it could secure a long-term gas contract at a price of approximately NZ$4-5/GJ. The scale of additional gas consumption would be approximately 19 PJ/yr, growing to that level over a period of between 4-8 years.

In contrast, it is likely that the any peaky demand growth will be most competitively met by new OCGTs, which could pay a price significantly greater than that which could be afforded by a new baseload CCGT.
However, the scale of extra gas demand to meet such peaky demand growth is likely to be relatively small. Thus, if non-heavy industrial demand growth were 2.2%, and 30% of this was peaky demand, this would translate into peaky demand growth of approximately 230 GWh/yr. If this were met by new OCGTs, this would result in additional gas demand of approximately 2 PJ/yr.
6 Gas for direct use

As Figure 17 below shows, the direct use of gas for energy in the residential, commercial and industrial sectors has been a relatively small, but steady source of New Zealand gas demand.

Figure 17: Historical gas consumption in New Zealand

Source: Concept analysis using MBIE data

The October 2014 study focussed only on North Island direct use of gas – being the only existing source of such demand. It identified that the potential rates of change of gas demand in such sectors would be relatively low, due to:

- Fuel choice decisions for consumers being driven by the capital replacement cycle of boilers and heaters (which typically are of the order of decades).

- Most of the significant opportunities to switch to gas for industrial process heat have already been taken up, and what opportunities do exist (particularly for switching from coal to gas for process heat) are of a relatively limited scale.

- Relatively little ability to ‘create’ significant new demand for gas through the development of new gas-consuming industries (other than the petrochemical industries discussed earlier). This is because gas is a relatively small factor input for the vast majority of non-petrochemical industries. Therefore gas price will have limited influence on an industry’s expansion or location decisions.

Accordingly, there appears to be limited potential for additional North Island direct use of gas to facilitate the commercialisation of significant new gas discoveries.

However, although all existing gas production is from fields in Taranaki, there is considered to be significant potential for gas finds in basins near the South Island – particularly the Canterbury and Great South Basins.
Although exploration effort to-date has not yielded finds which are large enough to be commercialised\footnote{To-date, there has been gas found in the Galleon well in the Canterbury basin, but this is not considered large enough to develop (either for offshore LNG production, or onshore gas production).}, there is continued interest in these basins as potentially having significant gas resources, and some further exploration is likely.
However, without the existing gas infrastructure and ready market that exists for Taranaki gas discoveries, gas discoveries in the South Island face an even greater challenge to achieve commercialisation.

This section considers whether direct use of gas for South Island industrial, commercial and residential energy uses represents a significant opportunity to help commercialise any gas that is found in the South Island.

6.1 Scale of potential demand for direct use of gas in the South Island

The opportunities for direct use of gas in the South Island are process heat for industrial/commercial applications, and space and water heating for commercial and residential consumers. Gas would need to be substituted for the existing fuels used to provide these energy services.

EECA’s energy end-use database provides a very useful breakdown of the quantities of fuels used for different applications and customer segments. However, the information is published on a national level, and thus not suitable for this purpose.\(^{52}\)

Accordingly, alternative approaches were adopted to roughly estimate the scale of potential demand that could be met by gas in the South Island, considering three main fuel substitution opportunities:

- Coal-fired boilers to provide industrial process heat. As the graph on the right illustrates, this is dominated by the dairy processing sector.

  ![Figure 19: Estimated South Island coal-fired process heat industrial sectors](image)

Source: Concept estimates

- LPG currently used to provide process heat for some large industrial sites, and substituting for the LPG currently reticulated in some of the main urban centres in the South Island.

- General space and water heating demand.

In all these cases only national data is available, so simple estimates were made of the proportion of demand met by South Island consumers.\(^{53}\)

The resulting estimates of the size of demand are shown in Figure 20.

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\(^{52}\) It is understood that regional information for the Energy End Use Database will be produced in the relatively near future. However, it was not available at the time this report was being produced.\(^{53}\) In the case of industrial coal consumption, it was estimated that 2/3 of consumption was in the South Island. For LPG demand it was estimated that the South Island accounts for 60% of demand, and that 50% of that was for reticulated networks and industrial bulk consumers. For space and water heating, national data was factored by the proportion of New Zealand’s population that are located along a trunk from Nelson down to Invercargill.
Figure 20: Estimate of the size of South Island direct use demand which could theoretically be met by gas

However, it is not reasonable to expect that gas could capture all of this demand because some locations may be too distant from a potential gas pipeline network (particularly for some industrial process heat locations), and gas for space heating may find it hard to compete against heat pumps. Further, it would likely take a significant amount of time for gas substitution to occur. This is because, as set out in a previous report for the Gas Industry Co\textsuperscript{54}, the sunk cost of the existing boiler gives the existing fuel a significant cost advantage such that fuel switching will be most likely to occur when boiler replacement decisions need to occur.

Accordingly, a further set of assumptions were made as to what proportion of the potential market gas could expect to capture, and over what period of time it would achieve this capture. These are set out in Table 6.

<table>
<thead>
<tr>
<th></th>
<th>Ultimate gas market share</th>
<th>Time to achieve full market share (yrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Process heat (displace coal)</td>
<td>60%</td>
<td>15</td>
</tr>
<tr>
<td>Process heat and reticulation (displace LPG)</td>
<td>90%</td>
<td>5</td>
</tr>
<tr>
<td>Space heating</td>
<td>30%</td>
<td>20</td>
</tr>
<tr>
<td>Water heating</td>
<td>60%</td>
<td>20</td>
</tr>
</tbody>
</table>

The market share assumptions for space and water heating were simple estimates based on the analysis undertaken in the Consumer Energy Options report. This analysis revealed that gas is very competitive for industrial process heat, and water heating, but that heat pumps were often (but not always) a more cost-effective form of space heating. It is also assumed that gas would largely displace LPG except in situations where the gas network does not reach some customers.

The market share assumptions for process heat were a simple guesstimate of the proportion of such demand that could be close to a South Island gas pipeline network.

\textsuperscript{54} “Consumer Energy Options: An evaluation of the different fuels and technologies for providing water, space, and process heat”, Concept Consulting, 22 November 2012
A further assumption was made that each of these energy end use segments would have underlying growth of 2% per annum.

Combining all of these assumptions results in the gas demand projection shown in Figure 21 below.

*Figure 21: Simple projection of growth in South Island gas demand*

This projection is necessarily based on very broad assumptions. However, it is considered to be a reasonable order-of-magnitude estimate of what is possible for gas uptake in the South Island. For comparison, total industrial (excluding the power generation and petrochemical sectors), commercial and residential gas demand in the North Island for 2013 was 35 PJ.

Demand of 20 PJ/yr could be sufficient to commercialise a small to medium-sized field similar to Kupe in size – although the seasonality of the demand profile could materially reduce the value to facilitating gas production.

However, if it were to take 20 years to achieve this level of demand, it would significantly adversely affect the economics of the field’s development. Indeed, it is unlikely to provide a viable demand profile, given the need to ramp up gas production early in a field’s life to provide commercial returns. Further, 20 PJ/year would be too small to commercialise a larger field, similar to Pohokura in size.

Taken together, these facts mean that the potential direct use of gas in the South Island would likely be insufficient *on its own* to facilitate the commercialisation of a new gas field.

Accordingly, it is likely that a new petrochemical facility (most likely urea or methanol) or a new gas-fired power station would be required to play the principal role in commercialising any new gas discovered in the South Island that was smaller than LNG-scale.

### 6.2 Net-back available to gas for direct use in the South Island

Another issue that was explored was the likely gas net back available for supplying a direct use customer. For this, the analysis was solely focussed on the coal for process heat segment given that it represents the significant majority of the potential direct use demand in the South Island.
The framework is based on consideration of the price of alternative fuels to provide industrial process heat. In simple terms, the price an industrial consumer would be prepared to pay for gas will be capped by the price they could pay for an alternative fuel to deliver an equivalent quantity of heat.

The analysis works out the maximum wholesale price an upstream gas producer could hope to receive for its gas in order to be competitive with alternative fuels. This is referred to as the ‘break-even’ gas price.

Two fuels are considered to be the main feasible alternatives: Coal for existing boilers, and biomass as an alternative fuel to gas for industrial consumers seeking to switch away from coal.

There are a number of different moving parts in determining the price of these two alternative fuels. Unless otherwise stated, the values for the different components are those set out in the related GIC study, “Consumer Energy Options”.

- Delivered fuel costs (i.e the price at the factory gate) of coal and biomass. Through informal discussions with various parties, it is understood that:
  - For coal, delivered costs to some major South Island industrial sites are approximately $3.50/GJ. It is likely that this cost will be greater for some other sites which are more distant from South Island coal mines. Conversely, some parties have suggested that some industrial sites may have coal priced at less than $3.50/GJ. For this study, $3.50/GJ has been used as a central assumption.
  - For biomass, delivered costs to industrial sites would likely be approximately $10-11/GJ on average, but with significantly greater variation compared with coal depending on proximity to forests. Thus, some sites may achieve delivered biomass costs of $7-8/GJ, whereas others could face costs of $13-14/GJ. For this study, $10.5/GJ has been used as a central assumption.

- The CO₂ emissions intensity of the fuel, and associated $/tCO₂ price. As previously discussed on page 55, the CO₂ price is a key factor in the sensitivity analysis, due to the uncertainty regarding future CO₂ prices. Accordingly a range of values from $0/tCO₂ to $150/tCO₂ have been used.

- Boiler capital costs. For coal, it is assumed that no capital costs will be incurred as the plant is existing. For biomass and gas, it is assumed that a new boiler will be needed. The capital costs for a new biomass boiler are estimated to be approximately ten times that of a new gas boiler.

- Boiler efficiency. The efficiency of a new gas boiler is considered to be greater than that of an existing coal boiler or new biomass boiler.

- Non-fuel boiler opex. New gas boilers are considered to have considerably lower operation and maintenance costs than existing coal boilers. New biomass boilers are considered to have non-fuel opex costs roughly mid-way between the other two.

- Gas transport costs. The starting assumption is that gas pipeline costs (transmission-only for very large industrial consumers, transmission + distribution for large industrial consumers) are the same as that being charged for customers in the North Island. This is probably an optimistic assumption as it is likely that gas transport costs for South Island consumers will be greater than for North Island consumers because there is not the same volume of gas over which to spread the cost of transmission and distribution infrastructure. For each $/GJ increase in transmission and distribution costs, the break-even wholesale price of gas will fall by an equivalent amount.

55 “Consumer Energy Options: An evaluation of the different fuels and technologies for providing water, space, and process heat”, Concept Consulting, 22 November 2012
The figures below show the results of this analysis for two different process heat situations:

- Very large industrial process heat boilers, approximately 40MWth\(^{56}\) in size, and assumed to be directly connected to the gas transmission network.
- Large industrial process heat boilers, approximately 7MWth in size, and assumed to be connected to a gas distribution network.

The main differences between these two situations are:

- Boiler capital and operating costs, which becoming proportionately much greater for smaller boiler sizes;
- Gas transport costs, which similarly grow significantly for smaller-sized boilers.

*Figure 22: Break-even South Island gas prices for very large industrial plant*

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\(^{56}\) MWth is the thermal output of a boiler, measured in MW.
If CO₂ prices remain at their current low levels, the maximum price which gas could be sold at in order to displace coal would be approximately $3.5/GJ. This rises as CO₂ prices rise, but eventually becomes capped and falls again when CO₂ prices rise to a level where biomass boilers become cost competitive with new gas boilers.

The maximum wholesale gas price would be if CO₂ prices were around $120/tCO₂, making gas competitive for wholesale prices of between $8-9/GJ. This breakeven gas price will fall for CO₂ prices below and above this $120/tCO₂ level. Further, as stated above, these values are based on the assumption that gas transport costs are equivalent to those in the North Island. It is possible the $/GJ pipeline costs could be greater in the South Island due to South Island demand being smaller and more dispersed than the North Island. If this is the case, it will lower the price at which upstream producers could sell their gas and still be competitive against coal or biomass alternatives. For each $/GJ increase in gas transport costs, the breakeven gas price will fall by an equivalent amount.

Overall, therefore, it would appear likely that the maximum netback available to gas producers in the South Island would be in the $4-6/GJ range. Further, to the extent that the cost of building gas transmission and distribution pipelines is more expensive on a $/GJ basis than the North Island, the netback will be less by an equivalent amount.
7 Summary of new demand options

Figure 24 below presents the estimated range of netbacks which could be achieved for selling gas to new sources of demand for New Zealand.

Figure 24: Estimated range of netbacks for new gas commercialisation options in New Zealand

As can be seen, for each option there is generally a considerable range of possible prices reflecting inherent uncertainty over factors such as:

- the future price of alternatives (e.g. overseas LNG developments; overseas sources of gas for petrochemical production; renewable sources of power generation; coal, or biomass for industrial process heat; oil for transport)
- future CO₂ prices
- the development cost of the options (e.g. the cost of developing LNG liquefaction facilities)

It should also be noted that these prices are the prices that would be paid for gas for which there is no field reserves risk. It is possible that reserves risk will result in a material discount in the above prices which could be achieved by a New Zealand gas producer.

The graph also distinguishes between those options for which there is likely to be an effectively ‘unlimited’ demand for any product that New Zealand can produce, and those for which demand could be materially constrained. This is likely to be a significant issue when considering options which could help commercialise significant new gas finds.

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57 Reserves risk is the risk that the quantity of gas in a field turns out to be less than expected.
Overall it would appear that for very large gas discoveries, LNG would represent the most valuable development opportunity. For sub-LNG-scale discoveries, new petrochemical developments appear to represent the best opportunity for commercialisation. Taken together, these options mean there should be a ready source of demand for significant New Zealand gas discoveries. As such, New Zealand should not be disadvantaged for exploration investment relative to other locations around the world which are distant from the ‘core’ oil and gas markets of the US, Europe and Asia.58

Demand constraints will mean that the other options will be unlikely, on their own, to facilitate the development of significant new gas discoveries. However, for each of these options there could be opportunities for profitable development on a case-by-case basis.

58 Oil and gas produced in these core markets will always be more valuable than produced in more distant locations, due to avoided transport costs. However many of these core markets have limited indigenous sources of oil and gas, and/or have sources which are relatively high cost to extract.
Appendix A. Natural gas based transport fuel technology

The ability to utilise different natural gas fuel options is determined in part by the technology.

Engine technology

There are two broad types of engine technology: spark-ignition and compression ignition. Natural gas-based fuels utilise these well-understood technologies. From this perspective, they are considered fairly mature technologies.

The type of engine appropriate for any particular fuel is dependent on the fuel’s chemical nature. This in turn affects its application. For example:

- In a spark-ignition engine, a mix of air and vaporised fuel is compressed and then ignited by a spark. Spark-ignition engines are suited to fuels like petrol, that:
  - Are volatile, and hence vaporise easily, allowing them to be readily mixed with air in the piston cylinder.
  - Are prone to detonation. A spark-ignition engine ensures that the fuel burns in a relatively controlled way, before it gets hot enough to self-ignite and explode.
  - Can withstand significant pressure before igniting, allowing meaningful energy output.

- In a compression-ignition engine, the fuel is injected as a liquid into the engine’s piston cylinders when they are at high pressure and temperature. The high temperature ignites the fuel. Compression ignition engines are suited to fuels like diesel that:
  - Do not vaporise easily, and hence cannot be readily mixed with air.
  - Are comparatively difficult to ignite, and when they burn, do so slowly. This means that they can self-ignite without risk of premature detonation.
  - May not withstand particularly high pressures before self-igniting. Because the fuel is injected at the last minute, the engine can operate at temperatures and pressures beyond what the fuel could sustain before self-igniting.

Because compression-ignition engines can operate at higher pressures and temperatures, they generally have greater torque and are more energy efficient than spark-ignition engines. Because of this, compression ignition engines have traditionally been better suited to high-load applications. However, many natural-gas based fuels are conducive to heavier-duty spark-ignition operation.

Natural gas is a vapour, and prone to detonation like petrol. It is therefore used in spark-ignition engines. It can be accommodated in existing petrol engines with some modifications. Petrol fuelled vehicles can be converted to run on CNG through the addition of a CNG storage tank and high-pressure CNG fuel-injection line. Diesel vehicles can also be converted by additionally installing a spark-ignition system, and adjusting the engine’s compression ratios.

LNG could similarly be accommodated in modified existing engines. However, the degree and cost of modification is higher because of the need to deal with cryogenic temperatures.

Retrofit vehicles will typically be capable of operating on either petrol or natural gas – though not both at the same time.

Spark-ignition engines designed to run on natural gas can also be factory produced. A bespoke natural gas engine has the advantage of being able to operate more efficiently and at heavier duty, because the fuel can withstand comparatively higher pressures. This results in comparable or better efficiency than a diesel engine. In addition, they can come at lower cost because they require less expensive exhaust and fuel-injection systems than diesel. A number of companies offer CNG or LNG trucks and buses.
The story is similar for methanol as for natural gas. It must be used in a spark-ignition engine. Engines can be designed for operating on pure methanol, allowing for superior performance relative to petrol, and the potential for use in heavy duty applications. However, because methanol is a liquid at ambient temperature and pressure, it can also be stored along with petrol in the same tank, and used as a blended fuel.

Blends of up to 15% methanol may theoretically be used in modern petrol engines with no modifications.\(^{59}\) Because methanol has a lower energy density, more of a methanol blended fuel needs to be injected into the engine for it to function and perform as well as with pure petrol. Modern cars generally have variable fuel injection systems and a feedback control loop, which allows the injector to adjust for some variation in the fuel content automatically, while cars produced before 1990 do not. Using methanol as a fuel also produces acids that can be corrosive to an engine, and so fuel-additives are generally required in the mix to help prevent degradation. Some more corrosion-resistant materials may be required for components such as the fuel tank. Methanol is also less volatile than petrol, so a co-solvent in the fuel blend helps to ensure the methanol mixes in properly and vaporises, particularly in cold weather. Without this, methanol would sit and accumulate in the fuel tank, increasing the concentration of methanol over time.

There are also engines designed to operate on a range of other percent blends, termed ‘fuel-flex’ vehicles. These are commonly designed for use with biofuels. Modern fuel flex vehicles do not come at any cost premium internationally, though they likely would if they were brought to New Zealand. The key difference compared to modern standard petrol vehicles is improved corrosion resistance and fuel injection, which can alternatively be achieved with minor modifications to existing engines. Fuel-flex vehicles are typically optimised for blends with 85% methanol (or ethanol in the case of biofuels). Because methanol does not vaporise easily, maintaining some petrol in the mix helps with starting the engine in cold weather, and gives visibility to flames if it is set alight (since methanol burns clearly).

Alternatively for heavy duty applications, methanol, CNG and LNG can all be used in a dual-fuel engine. These are compression-ignition engines where the diesel acts as a ‘liquid spark-plug’, igniting an air/fuel mix. A dual-fuel engine therefore typically consumes both fuels at the same time, though some can also continue to operate exclusively on diesel. While not new, computerised optimisation has improved the performance of dual-fuel engines, leading to greater promise for this technology. Dual-fuel engines have the advantage of:

- the efficiency and heavy duty performance associated with diesel engines
- fuel flexibility
- in some cases, being able to be converted from existing diesel engines (though retrofits generally operate less efficiently than bespoke engines)

The disadvantage is that only some diesel is displaced in dual-fuel operation; generally between 50-70%. Engines that continue to operate on diesel also continue to require costly exhaust systems.

There is much less experience with DME as a vehicle fuel. It is functionally similar to a high-quality diesel fuel, requiring a compression-ignition engine, and achieving similar engine performance. It can be used in existing engines with low-moderate modifications. These modifications primarily relate to seals, storage, and the fuel injection system, as DME is a lower energy-density gas, but exists as a liquid at moderate pressure of around 5 bar (similar to LPG). DME has poor lubricant properties, requiring special additives to avoid wear failure in engines.

DME would capture the performance benefits currently derived from diesel engines, without the severity of storage issues caused by CNG or LNG. DME has around half the energy density of diesel,

\(^{59}\) Some older vehicles may suffer issues such as degradation of seals.
so requires a larger fuel tank for equivalent range, under moderate pressure, with associated weight implications. However, it is much cleaner burning than diesel, so would avoid the need for an expensive exhaust system, which has associated weight-saving advantages.

DME can also be used in LPG vehicles as a blended fuel.

Synthetic fuels can be used in existing petrol or diesel engines without modification.

A summary of the ignition and engine requirements of the different fuels is given in Table A1.

Table A1. Ignition and engine requirements of different natural gas-based fuel options

<table>
<thead>
<tr>
<th>Ignition technology</th>
<th>Engine required</th>
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<tbody>
<tr>
<td></td>
<td>Spark</td>
</tr>
<tr>
<td>CNG</td>
<td>✓</td>
</tr>
<tr>
<td>LNG</td>
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<tr>
<td>Methanol</td>
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<td>Low-% methanol blends</td>
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<tr>
<td>DME</td>
<td>✓</td>
</tr>
<tr>
<td>Other synfuels</td>
<td>✓</td>
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</tbody>
</table>

Tank technology

Tank technology is fairly mature.

CNG tanks need to be able to contain gas under high pressure. In this regard, tank cost and weight are inversely proportional:

- the cheapest tanks have heavy solid steel walls, weigh 4-5 times that of a petrol tank with equivalent energy capacity, are three times the size, and cost around $32/litre of petrol equivalent capacity
- more sophisticated tanks have hooped carbon fibre composite wrap over thinner walls, weigh 2 times that of a petrol tank with equivalent energy capacity, and are around four times the size, and cost upward of $64/litre of petrol equivalent capacity

LNG tanks need to be double-walled, with a vacuum in between for thermal insulation, and strong enough to maintain moderate pressure of around 8 bar. LNG tanks use about 30% of the storage space of a CNG tank with the equivalent energy capacity, but are still heavy, and still require a large volume to get a meaningful range.

Furthermore, due to imperfect insulation, LNG in the tank will boil-off over time, increasing pressure in the tank. A pressure release valve will vent gas in order to maintain pressure. This would contribute to greenhouse gas emissions, leak valuable fuel, and could be hazardous in enclosed spaces like garages. To avoid these issues, LNG is best suited to applications where the fuel is used regularly – i.e. within 1-2 weeks. This issue is a key reason why LNG is not suited to light vehicle transport.

DME is liquefied at moderate pressures and it can be stored like LPG due to its similar properties.
All tanks need regular inspection and replacement after some time to prevent failure. They are generally designed to have 15-20 year lives. Stress, corrosion, over-pressurisation, fire, and other issues, can all contribute to tank failure.

Adsorbed natural gas is a future development possibility for gas storage. Adsorbed natural gas ‘sticks’ to the surface of certain materials, at relatively low pressure and ambient temperature. This overcomes both the pressure and temperature problems of CNG/LNG (though is also improved by increased pressure and/or decreased temperature). However, the energy density that can be achieved by adsorbed natural gas is currently too low for it to be a useful storage option.

To avoid corrosion, high-% methanol blends require fuel tanks made of a different material than conventional fuel tanks. Low-% methanol blends and synthetic fuels can utilise standard fuel tanks.

Production and refuelling infrastructure technology

Production and refuelling infrastructure varies significantly for the different fuel options.

CNG requires the least infrastructure. It can be supplied by existing natural gas pipelines, and then compressed on site. There are two options for refuelling; fast-fill and time-fill:

- **Fast-fill** takes the same time as refuelling a regular petrol vehicle, and is hence best suited to retail applications. The gas is compressed, and then stored at pressure in storage vessels, which dampen variations in demand relative to production. Vehicles then refuel from the storage vessels using a nozzle dispenser, which has sensors to measure quantity and pressure.
- **Time fill** stations are used primarily for fleet vehicles that refuel at a central location, and can refuel overnight. Vehicles are filled directly from the compressor. The time taken varies based on the design – ranging from several minutes to some hours. However, they can take on a greater quantity of gas, because the gas – having heated up under pressure – has time to cool down and compress further while refuelling. Slow-fill can also benefit from cheaper electricity rates by refuelling at off-peak times. At-home refuelling stations use this slow-fill approach.

LNG can be supplied from existing natural gas pipelines, but then requires refrigeration down to very low temperatures. It can be produced on a ‘micro’ or ‘macro’ scale – ranging from around 20 tonnes per day to over 20,000. Micro-LNG may be done on-site, particularly for fleet vehicles. Macro-scale LNG would likely involve distribution of the liquefied gas in ‘bullet’ storage containers via road tanker, to a number of satellite storage facilities. From there, refuelling would operate similarly to that for normal petrol vehicles, though it requires thermally insulated pipes, more advanced nozzles, and gloves to be worn. LNG refuelling can also be performed by a mobile tanker.

Methanol, DME and synthetic fuels all require specialised production facilities, but can use much of the existing refuelling infrastructure used for petrol and diesel:

- **Methanol**:
  - Is already produced in NZ at scale by Methanex, using natural gas as a feedstock.
  - Being liquid, methanol does not require substantially different refuelling infrastructure to that which exists for petrol. Low-% methanol blends could utilise existing infrastructure, while some different materials will be required for high-% blends.

- **DME**:
  - Can be produced directly from natural gas, or through a two-step process that first produces methanol. Both processes are used internationally, though the two-step process is more ubiquitous.
  - DME is generally produced in macro-scale production facilities – i.e. similar (generally larger) in scale to the Taranaki methanol production plant. However, some companies are beginning
to develop small-scale processes (~20 tonnes per day), which are supporting pilot DME trucking projects in the USA. Production as this scale could allow for regional transport developments or use by return-to-base vehicles, and support development of stranded gas fields. These facilities can also produce methanol as an alternative.

- Because DME has similar properties to LPG, the refuelling infrastructure required would be similar.

- **Synthetic fuels:**
  - Are produced using gas-to-liquids processes, which convert natural gas into longer-chain hydrocarbons. The main processes are:
  - Production of synthetic petrol using the Mobil process, though it does not appear to be presently employed anywhere. This process has the production of methanol and DME as intermediate processing steps.
  - Production of synthetic crude that can be refined into diesel, from natural gas with no intermediate products. This process has, to date, only been applied at very large scale facilities of around 15,000 barrels per day or more. The most recent investment produces up to 140,000 barrels per day, requiring around 600 PJ/annum in natural gas feedstock. However, some companies are beginning to produce much smaller-scale technology – around 1,000 barrels per day, which requires around 4 PJ/annum. Floating production technology is also being developed.
  - Because synthetic petrol and synthetic diesel is essentially identical to conventional petrol and diesel, synthetic fuels can rely entirely on existing refuelling infrastructure.
Appendix B. Overseas experience and uptake of natural gas-based fuels

Natural gas

According to the Natural and bio Gas Vehicle Associate Europe (NGVA)\(^60\), there are over 17 million natural gas vehicles on the road internationally, the vast majority of which are light-duty CNG vehicles.

The extent to which natural-gas is utilised varies from country to country, based on the natural gas position and consequent price benefits, and the extent to which the country’s government incentivises its use.

The International Energy Agency projects that natural gas vehicles will grow from accounting for 1.4% of total world gas demand in 2012, to 2.5% by 2018. More than half of that growth is expected to come from China, following recent trends – a result of air quality concerns. However, notable increases are also expected in OECD countries, driven by environmental standards, and the USA\(^61\) driven by the wide spread between oil and gas prices. Conversely, some of the countries with the highest share of natural gas vehicles – Pakistan, Argentina and Iran - are facing gas shortages, so growth in those areas is likely to stagnate. Pakistan is reportedly looking to phase out private use of CNG\(^62\).

CNG\(^63\)

Generally speaking, the CNG vehicles in use are converted petrol/diesel vehicles. However, a number of car companies, including Honda, Fiat, and Ford, have recently introduced CNG-specific vehicles.

New Zealand previously had a fairly vibrant light-duty CNG market. The government incentivised conversion to CNG to provide a demand-source for its take-or-pay agreement with the Maui gas field, and in response to high oil prices. Under the government’s program, the number of CNG vehicles doubled every year, eventually reaching 120,000 vehicles, or around 10% of all spark ignition engines at the time.\(^64\) At the market’s peak in 1985, CNG vehicles consumed 5.85 PJ, and featured an extensive North Island-wide refuelling network.\(^65\)

However, when subsidies were later removed, interest in CNG vehicles collapsed, and the market eventually died.\(^66\) There remain a number of companies in New Zealand that retain the CNG refuelling expertise, which they now export overseas.

A number of municipalities worldwide, including areas of the USA, Seoul in South Korea, and Singapore, use CNG powered buses. CNG refuse vehicles are also in use in some places. While economic benefits are possible for these heavy-duty vehicles, it appears that consumers in some countries have struggled to realise these due to poor engine performance negating any fuel price advantage. The primary benefits have hence been environmental (particularly reduced particulate emissions) and noise benefits.

\(^60\) http://www.ngvaeurope.eu/worldwide-ngv-statistics
\(^64\) http://www.btb.co.nz/article/award-good-news-nz-natural-gas-car-industry
\(^65\) Ministry of Economic Development, Energy Data File 2004, table E.5
**LNG**

LNG as a transport fuel is a more novel application, and its use is not wide-spread. On the road, it is restricted to heavy duty vehicles – i.e. LNG trucks and buses.

An increasing number of truck engine manufacturers are beginning to offer LNG options, including Volvo and Cummins Westport.

Dedicated LNG trucking lanes are being established in areas of the USA, Europe and in Australia (between Melbourne and Sydney). These go along high-volume trucking routes, and provide LNG fill-stations along the way. These initiatives are being spearheaded by a range of companies that see significant potential in LNG for heavy-duty vehicles, including the likes of Shell and BOC. In Europe, the European Union and NGVA aims to coordinate cooperation between gas suppliers, vehicle manufacturers, haulage firms, and local organisations to expand the LNG trucking network.

China operates an increasingly large number of LNG buses – both long-distance and urban transit. Refuelling infrastructure is also being rolled out in support, including a railway corridor for LNG transportation that is being developed with government assistance.

LNG is also likely to be an increasingly common fuel option for marine transport, particularly in Europe where stringent European Union environmental standards (particularly with regard to sulphur emissions) will necessitate expensive modifications for traditional fuels to remain in use. LNG (which can be retrofitted into existing ships) is suggested to be the option that will meet the standards at least cost. It is advantaged for use in the Baltic sea because LNG infrastructure already exists in some coastal areas. However, in absence of the environmental restrictions, the economic case has not yet necessarily been proved.

Pilot projects investigating the feasibility of LNG as a locomotive fuel are underway in the USA.

**Methanol**

Around 50% of all methanol sold globally goes to energy and fuel uses.

Methanol has been used in racing cars for years. It can provide superior engine performance, and is safer in a racing setting because it doesn’t explode like petrol does, and burns clear so does not impede vision of the race track if set alight. Methanol was also used as a transportation fuel in various blends until the mid-1990s in North America and Europe, when it lost popularity and was phased out.

China is now the largest user of methanol as a transport fuel. Methanol provides around 8% of the country’s fuel supply, though its availability varies between China’s various provinces. Methanol has been supported for environmental, economic, and availability reasons – since methanol is produced domestically from a relatively low cost source of coal in large volumes.

In China, methanol is available in a variety of blends, ranging from 5% to 100% methanol, and is used in a variety of ways:

- Low blends up to 15% methanol (being the most popular) are widely available for general light duty use in existing vehicles. A co-solvent is used in the mix.

- Around 80,000 taxis operate fuel-flex vehicles running on 100% methanol and 85% blends. Around 30,000 vehicles are converted to exploit this option each year.

- Hundreds of buses and commercial vehicles also use 100% methanol and 85% blends, with thousands more planned to be introduced.

- A number of Chinese automakers have rolled out cars that can run on 100% methanol or 85% blends.
There are over 1,500 service stations offering methanol blends, which is expected to continue to climb.

China has various national and local standards for methanol blending. However, there are suggestions that there is a significant amount of fuel blending that is done illegally to exploit methanol's favourable economics. 67

The European Union has approved methanol blending up to 3% with a co-solvent. At such low concentrations, this was considered to not have any potential detrimental impact on vehicles 68, and thus does not require the fuel to be identified as a methanol blend. However, blending is not yet commonly done. 69

Various other countries, including the UK, Iceland, Israel, Australia and many others, are exploring or dabbling in methanol as a transport fuel – conducting pilot programs and demonstrations of various methanol blends.

In the USA, the interest has been primarily on ethanol rather than methanol, because of the agriculture industry’s interest in bio-ethanol. While a number of fuel-flexible vehicles are available in the USA, they are generally designed to use ethanol. The USA also commonly blends up to around 10% ethanol into petrol.

Methanol blending in the USA has previously been disadvantaged by legislation relative to ethanol, but this has or is being amended. Blends of up to 5% methanol are allowed, with 2.5% co-solvents (being ethanol or higher alcohols). However, because ethanol blending is already common, this practically limits the ability to also blend in methanol.

A critical issue for the uptake of methanol blending is whether vehicle manufacturers will issue warranties for standard vehicles using low-% methanol blends. As set out in Appendix A modern vehicles are generally able to accommodate methanol blends up to 15% without issue, but older vehicles may suffer performance problems.

Currently there is little incentive for vehicle manufacturers to issue warranties, and overseas initiatives to adopt methanol blending are likely to be critical to NZ’s ability to do so: If Chinese manufactured vehicles start to take market share from other vehicle manufacturers in China because they have warranties for methanol blends, this may provide a spur for the other manufacturers to also issue warranties. Similarly, Australian initiatives may make it easier for NZ to coat-tail.

**Dimethyl Ether (DME)**

Dimethyl ether has yet to make an impact on the transport sector, though it is produced in a number of countries for other purposes. The market for DME is also growing (it is a popular alternative to LPG in developing countries), and production therefore expanding.

While it appears to be regarded as a quality alternative to diesel, particularly because it does not have any particulate emissions, its transport applications appear to be largely in the development phase.

Volvo is producing a DME version of its top-selling heavy-duty engine, which will be available in North America from 2015. It has partnered with Oberon Fuels, who have developed a process that allows production at very small scale, which would support a return-to-base fleet, or regional

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67 [http://www.iea-amf.org/content/fuel_information/methanol](http://www.iea-amf.org/content/fuel_information/methanol)

68 As set out on page 55, methanol can potentially detrimentally affect some older vehicles.

trucking for various fleets. Volvo has suggested that of seven alternative fuel options it investigated, it has prioritised DME as a preferred development option.\(^\text{70}\)

### Other synfuels

New Zealand has previously had a foray into synthetic fuels. Beginning in 1986, Mobil trialled its methanol-to-gasoline process in its world-first facilities at the Motunui methanol plant. It produced a premium unleaded petrol blend-stock, which was shipped to the Marsden Point refinery, and blended with conventional fuels for direct use by the transport sector. Annual production was around 570,000 tonnes – sufficient at the time to fuel around 1/3 of the petrol market. \(^\text{71}\)

The Mobil facility was intended to reduce NZ’s dependence on foreign oil during a period of very high oil prices. However, by the time it began producing, oil prices had dropped, making the plant uneconomic. The plant therefore switched to making more methanol, and produced its last synthetic petrol in 1997. \(^\text{72}\)

Synthetic diesel is produced in Malaysia, Qatar and South Africa. All these plants are very large in scale – the smallest producing 15,000 barrels per day -and generally have low-cost feedstock that is unsuited to development into LNG. Total production is around 0.25 million barrels per day.\(^\text{73}\) There are other plants under construction in Nigeria and Uzbekistan.

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Appendix C. Investment in new fuelling infrastructure and distribution networks

For any natural gas-based fuel to substitute existing fuels, changes will be required to fuelling infrastructure and distribution networks. The level of investment required will vary for different alternative fuel options. Specifically:

- **CNG production and distribution facilities** are one and the same. Compressor stations for CNG could be sited near any of the existing natural gas pipelines. Fast and slow-fill options exist, both of which are more expensive than equivalent petrol/diesel stations, though costs will vary based on design and size:
  - CNG compressor stations can vary from $US 10,000 to $US 2 million per station. Slow-fill stations cost less than fast-fill.\(^74\)
  - Home-fill comprises the lowest cost option of $US 10,000 + install costs. However, home-fill is disadvantaged by retail gas and electricity (for operating the compressor) prices, on top of the need to fully recover capital costs.

CNG filling stations will also be limited to those located close to the existing gas reticulation network. This will mean that it will not be practicable to have CNG filling stations in some parts of the country, particularly rural New Zealand and the South Island. This will significantly contribute to consumers’ ‘range anxiety’ and act as a serious barrier to mass uptake of CNG light vehicles.

- **LNG** would require liquefaction facilities, and at a minimum, storage and re-fuelling equipment. Depending on the approach, it may also require loading systems and road tankers to distribute it to satellite storage stations.
  - The cost of LNG liquefaction facilities varies considerably depending on scale. It is understood that micro-scale facilities, producing around 7,000 tonnes per annum - enough to service around 100 trucks per day - could cost around $US 3 million.\(^76\)
  - Storage could cost around $US 1.5-3/litre of capacity.
  - The mechanical systems for LNG refuelling can cost from $US 350,000 to $1 million, compared to $50,000 - $150,000 for a petrol/diesel refuelling station.\(^76\)
  - LNG tankers and loading systems are understood to cost around $US 500,000.\(^77\)

- **Natural gas synthesised fuels:**

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\(^74\) [http://www.afdc.energy.gov/fuels/natural_gas_infrastructure.html](http://www.afdc.energy.gov/fuels/natural_gas_infrastructure.html)

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Traditionally require large capital-intensive production facilities, which would require a significant gas find to support them, and an international market for the product as New Zealand’s size would unlikely absorb all production. However, technology advances have led to a number of companies starting to develop micro-scale production facilities for some fuels, which could potentially be utilised here. Production costs will vary:

- Methanol is already produced in NZ, so would not have any additional production costs.
- DME is generally produced at very large scale, but at least one company offers facilities that produce between 5-10,000 tonnes per annum, which are estimated to cost around $US 10 million.
- Synfuels are also only produced at very large scale internationally (see Appendix A). Furthermore, only synthetic diesel is in production. Smaller scale gas-to-liquid facilities (for producing synthetic crude which can be refined into diesel and naphtha) are starting to become available, with a 50,000 tonne per annum facility reported to cost around $US 100-150 million.\(^78\)
- Could be distributed in a similar manner to existing fuels. Additional storage and dispensary costs would vary depending on the extent to which they were blended with other fuels. Some alternative materials could be required for pure methanol or high-percent blends. Adding around 40 m\(^3\) of methanol storage, plus dispensers and piping, to an existing fuel station could cost around $US 100,000.\(^79\)

Companies will be hesitant to invest the necessary capital into production and distribution infrastructure and refuelling networks if the demand is not there to ensure a return.

Figures C1 and C2 show the estimated cost per litre of petrol equivalent (LPE), that would be required to recover the fixed production and distribution costs associated with alternative fuels, for a given number of light and heavy duty vehicles respectively.\(^80\)

\(^80\) [http://www.methanol.org/energy/transportation-fuel/methanol-fueling-station-costs.aspx](http://www.methanol.org/energy/transportation-fuel/methanol-fueling-station-costs.aspx)

Light duty vehicles are assumed to travel 10,000km/yr on average, with a fuel/km rate of 7.9 l/100kms. Heavy duty vehicles are assumed to travel 100,000km/yr on average, with a fuel/km rate of 40 l/100kms.
This suggests that, depending on the extent of variable costs:

- **CNG** fixed costs could be recovered most efficiently from a relatively small fleet of some 100s of light-duty vehicles, or a small fleet of heavy vehicles.
- **LNG** and **DME** would likely require closer to 10,000 light-duty vehicles. However, they are more suited to heavy-duty applications, and could be recovered from a fleet of around 100 trucks at lowest fixed costs per litre.
- **Methanol** would have the lowest fixed costs per litre at scale because it would be able to utilise existing production facilities, and can utilise existing or similar distribution facilities.
• Synfuels would require a much greater number of vehicles before the capital costs associated with the larger and more expensive production facilities, could be recouped at a price competitive with conventional fuels.

To achieve this scale, alternative fuels will need to be readily available where and when they’re required so that they are an appealing option for consumers. This can create a chicken-and-egg situation.

Some natural gas-based options will avoid this range anxiety issue. For example:

• Synfuels could achieve immediate scale, as they can be readily mixed with existing fuels and utilise all the associated infrastructure.
• Subject to addressing issues with vehicle warranties, blending methanol with existing fuels at low levels (i.e. less than 15%) would similarly overcome the need for widespread distribution, as it could be accommodated in existing distribution networks.
• Options where vehicles are able to continue using conventional petrol or diesel exclusively when the alternative fuel is not available will avoid some issues with availability. This includes bi-fuel, dual-fuel, and fuel-flex vehicles\(^{81}\).

For other options to achieve the necessary scale, they would need to be rolled out progressively. In this regard, they would likely first be adopted by return-to-base applications. Return-to-base applications often achieve the scale required with a smaller number of vehicles because they are high-use consumers, can bypass range anxiety issues, and can be served by a single custom-sized filling station, thereby avoiding the need for widespread infrastructure and ensuring a predictable number of returning vehicles.

In this regard, local and regional trucking companies are the heavy-duty applications most suited to early investment in LNG, CNG, DME or high percent methanol blends. Transit buses and refuse trucks would also be appropriate early-adopters. Taxis and couriers may be potential light-duty contenders.

Establishing refuelling infrastructure along dedicated high-volume routes would be the next step, as is occurring in Australia, Europe and the USA for LNG. Assuming a similar effort was made in NZ between, say, Auckland and Wellington, this would span 650km. It is possible that many natural gas-based trucks could make this trip one way on a single tank of fuel\(^{82}\), even accounting for the lower energy density of CNG, LNG, DME and methanol. Therefore, if the density of heavy duty vehicles who only travel along this route was sufficient, a corridor could be established with alternative fuel refuelling available at just the two end-points.

The next and most challenging step would be a more widespread roll-out of infrastructure. According to a study examining fuelling infrastructure concentration\(^{83}\), there needs to be approximately 1,000 vehicles per fuelling station for the station to be profitable. Furthermore, this study suggested a minimum of 10% of all service stations need to supply an alternative fuel before accessibility ceases to be a major disincentive for consumers.

\(^{81}\) i.e. vehicles that can switch between exclusive use of two different fuels, vehicles that typically use two fuels at the same time, but can use one exclusively if required, and vehicles that use a blended fuel.

\(^{82}\) Assuming a 150gallon fuel tank size, fuel efficiency of 36 l/100kms for diesel and equivalent energy for alternative fuels, and 20% reduced efficiency for spark ignition engines. Under these assumptions, only a CNG and methanol truck would have sufficient fuel to make the trip.

According to the AA, there are around 1,300 service stations in New Zealand\textsuperscript{84}. Therefore, to support mass market adoption, an alternative fuel would need to be available at a minimum of 130 of these, and therefore, approximately 130,000 alternative fuel vehicles would be required (assuming even distribution). This would represent approximately 5% of the light passenger vehicle fleet in NZ\textsuperscript{85}.

However, progressive roll-out may not be practical where a fuel can only be produced by large-scale facilities. For example, Synfuels, DME, LNG and methanol have traditionally been built at very large scale. Such large-scale investments would require immediate scale of distribution, or an alternative market for the products while they penetrate the transport sector, or to direct any overflow. In this regard, the potential development of Synfuels, DME or LNG for domestic transport purposes would rely heavily on the small-scale production facilities that are starting to become available internationally.

\textsuperscript{84} http://www.aa.co.nz/cars/maintenance/fuel-prices-and-types/service-stations/
Appendix D. Consumer investment in new vehicle technologies or engine modifications

As well as the investment required from suppliers and/or distributors, the ability to displace existing fuels with natural gas based alternatives will require consumer buy-in. This is much more likely where the investment cost and effort for the consumer is low. There are some specific factors to consider in this regard, including:

- The extent of vehicle modification required:
  - Options that require no engine modifications will be the most palatable to consumers, as it does not require them to invest in or do anything. Furthermore, if consumers can continue to utilise existing fuels, range anxiety will not be a concern. Both low-% methanol blends and synfuels could utilise existing engines with no modifications.
  - Higher methanol blends would require minor engine modifications, but could continue to utilise conventional petrol. This may not present a significant barrier for many consumers, particularly if modifications could be made during regular maintenance. Furthermore, fuel-flex vehicles internationally do not typically come at any price premium (although they may do in New Zealand).
  - LNG, CNG, and DME, all require moderate engine modifications or bespoke engines. This has impacts on a number of levels:
    - For light-duty CNG, converting an existing engine costs in the order of $2-5,000. The price premium on a new bespoke CNG engine is slightly higher than this at around $8,000. For heavy duty vehicles, new CNG vehicles are typically 10-15% more expensive than an equivalent diesel. It is likely that this level of investment would materially affect uptake. Uptake of CNG vehicles in New Zealand in the 1980s relied heavily on generous government incentives, and collapsed when those incentives were later removed.
    - Retrofits of existing engines are cheaper than bespoke engines, but are disadvantaged by being non-optimised for the alternative fuel. This may be a particular concern for heavy duty vehicles, where fuel efficiency has significant cost implications.
    - Consumers are also less likely to invest in new or modified engines without widespread availability of alternative fuels at service stations. They will also require confidence that the alternative fuel will continue to be available for the life of the vehicle. These issues may be particularly significant given that CNG has come and gone in NZ before. Users may therefore be wary about this happening again.
    - Maintenance costs may be higher for alternative-fuel vehicles (they may also be lower for some options – e.g. DME).
    - It should also be noted that adopting alternative fuels may have quality considerations. For example:
      - Fuel tanks for some alternative fuels can take up a lot of space in a vehicle, given their lower energy density. They are often also heavier because of the need to contain a gas under pressure, or the need for thermal insulation. These factors may be off-putting for some consumers, particularly if it requires a trade-off for storage space, or their ability to transport their product under truck weight limits.
      - There are safety concerns to consider for high-pressure or cryogenic cylinders and fuels, which may also have a significant impact on consumers’ desire to switch fuels.
Vehicles using alternative fuels, particularly if retrofitted, may also have reduced engine performance (reduced power, increased engine ‘knock’ etc.). Spark ignition engines are less efficient than compression ignition engines, so moving from diesel to CNG, LNG or methanol engines has an associated reduction in energy efficiency, and hence greater fuel use.

- Potential safety issues relating to LNG-fuelled vehicles. Even though LNG is stored in a cryogenic tank on the vehicle, some fraction of LNG will constantly be boiling-off. After around 1-2 weeks, the extent of boil-off will require venting of some gas to maintain pressure. This typically makes LNG inappropriate for mass-market, light-duty operation, as there is no guarantee that such vehicles will consistently be used within every 1-2 weeks.

- The need for consumers to change their behaviour. Uptake of alternative fuels will be easiest where the need for changes in consumer behaviour is minimal. Behavioural changes may be required where:
  - Refuelling infrastructure or mechanics are only available in some locations, requiring consumers to drive further or go out of their way to access them.
  - The refuelling process is different. For example:
  - Alternative fuels with a lower energy density may require more frequent refuelling stops.
  - LNG refuelling requires the use of special gloves, and may necessitate greater reliance on forecourt attendants.
  - CNG slow-fill stations would require that vehicles are left overnight or for long periods in order to refuel.

- The availability of alternative-fuel vehicles in NZ. Again, this has a number of limbs:
  - NZ is a technology taker on the world vehicle markets, so widespread availability of alternative-fuel vehicles is unlikely before they are more ubiquitous elsewhere.
  - The small size of the market in NZ may mean that price premiums for alternative fuel vehicles are higher here. The key markets pioneering alternative fuel vehicle technology (Europe, US and China) have left-hand drive vehicles. In the absence of a large right-hand drive market for alternative fuel vehicles, this effect may be exaggerated.
  - Maintenance costs will be higher where the necessary expertise is more specialised and scarce.
  - The resale value of vehicles will also be a significant factor. Commercial fleet vehicles will generally only be in service for a hand-full of years, after which the operators rely on a liquid second-hand market to on-sell them. Furthermore, a large proportion of household vehicles are purchased second-hand. Uptake amongst these consumers is therefore likely to be inherently slow.
  - A critical issue for the uptake of methanol blending is whether vehicle manufacturers will issue warranties for standard vehicles using low-% methanol blends. Although low % methanol blends are unlikely to cause any issues for vehicles\textsuperscript{86}, particularly vehicles produced

\textsuperscript{86} Specifically in terms of operating performance or degradation of fuel-system materials (particularly aluminium). Modern vehicles use more corrosion-resistant materials, and have fuel injected engines with automatic feedback control, which ensure sufficient fuel-flow to maintain consistent power and drivability, and cold-start performance.
after 1990\textsuperscript{87}, vehicle manufacturers have shown little or no interest in issuing warranties that cover such fuels. Currently there is little incentive for them to do so, meaning that overseas initiatives to adopt methanol blending are likely to be critical to NZ’s ability to do so: If Chinese manufactured vehicles start to take market share from other vehicle manufacturers in China where methanol blending is widespread, because they have warranties for methanol blends, this may provide a spur for the other manufacturers to also issue warranties. Similarly, Australian initiatives may make it easier for NZ to coat-tail.

Appendix E. Competition with other emerging transport alternatives

The interest in vehicles running on natural gas based fuels, and their ability to gain some market share, will also be impacted by other emerging transport options.

Advances in battery technology mean that electric vehicles (including hybrids) are getting closer to cost parity with petroleum-based vehicles. Electric vehicles are suggested to be well suited to New Zealand’s largely renewable-based electricity system. Uptake of electric vehicles in New Zealand is still marginal, but is expected to build as the technology expands internationally and vehicle prices come down.

Electric vehicles (and hybrids) could impact natural gas-based vehicles’ ability to gain market share. The natural gas-based options that might conceivably face competition from electric vehicles are bespoke CNG, LNG, methanol and DME vehicles, as well as fuel-flex vehicles for use with methanol blends. There are factors that would both advantage and disadvantage natural gas-based vehicles relative to electric vehicles, including:

- **Fuel costs.** Assuming electric vehicles are charged overnight, and can access cost-reflective night tariffs, electric vehicles would have fuel costs of around 30c/LPE. This would be the lowest fuel cost of all the fuel options considered by some margin. Vehicles using natural gas based fuels may struggle to compete with electric vehicles because they are less competitive on this basis. New cars purchased in NZ tend to be bought by ‘high users’, for whom operating costs will be a significant consideration (low users tend to purchase second-hand cars).

- **Upfront and maintenance costs.** Electric vehicles and natural gas-based vehicles will both come at a price premium. In the short-term at least, the premium for natural gas-based fuels is likely to be lower. Fuel-flex vehicles in particular do not typically have an associated price premium internationally. However, continuing advances in battery technology mean the rate of cost reduction in electric vehicles could be faster than for natural gas-based vehicles. Furthermore, electric vehicles will likely have lower maintenance costs because they have a simpler drive train.

- **Range anxiety:**
  - This will be a significant concern for battery-only electric vehicles (i.e. electric vehicles with no secondary fuel source), and will likely remain so pending advances in battery and/or recharge technology, and roll-out of recharge stations. On the other hand, they could be charged at home, so for light-duty applications there may be fewer limitations in terms of the need for distribution infrastructure, particularly in the early stages of uptake/roll-out. Further, plug-in hybrid electric vehicles, and range extended electric vehicles may act as ‘bridging’ technologies that overcome the range anxiety issue for consumers.\(^{88}\)
  - Many natural gas-based options that would be relevant to the new-vehicle market (e.g. LNG, CNG, and DME) would also likely suffer some range anxiety. The exception to this is vehicles that can continue to use existing fuels, such as fuel-flex vehicles, or return-to-base vehicles where the need for widespread distribution infrastructure is avoided.

\(^{88}\) Plug-in hybrid electric vehicles (PHEVs) have two drive trains: an electric drive train, and one powered by the internal combustion engine. Range extended electric vehicles (REEVs) only have an electric drive train, but have an internal combustion engine whose sole purpose is to top up the battery when it gets low. This ability to use petrol to extend the range of both PHEV and REEV vehicles may eliminate range anxiety concerns for consumers.
• Application. Generally speaking, natural gas-based vehicles may be a preferred option relative to battery-only electric vehicles for heavy duty applications – particularly long-haul applications. This is because high-load applications would necessitate electric vehicles with very large and expensive battery banks, which may take a long time to recharge. Hybrids may be appropriate for heavy-duty however. Electric vehicles may be preferable for light-duty vehicles, for which LNG is generally not an appropriate technology option, and CNG has been tried before in New Zealand and since been withdrawn. Fuel-flex vehicles are the only natural gas-based, new-vehicle option that would likely compete in the light-duty market.

• Environmental factors: Electric vehicles will have significantly lower associated greenhouse gas emissions (assuming night-time charging) – particularly in New Zealand’s renewables-dominated electricity generation fleet. This may give their uptake comparatively greater impetus.

If electric vehicles look likely to have significant uptake it creates a risk for those natural gas-based fuels requiring significant investment in fuel production and distribution infrastructure. In this respect, it appears that light vehicles appear to be well suited to electric vehicles, but heavy vehicles will be less-suited.