Woodward Partners

Discussion Paper: Commercialisation issues, opportunities and challenges in the event of substantive gas-rich exploration success in New Zealand

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Key points

In the context of an improving gas supply outlook and an unprecedented pending period of oil and gas exploration activity, Gas Industry Company (GIC) has engaged Woodward Partners to consider the first-order commercialisation issues, opportunities and challenges that would likely accompany a substantive new gas discovery in New Zealand.

Our key conclusions:

1. Offshore-only the most likely South Island 'big gas' development scenario: A large gas or gas-condensate discovery in the South Island would likely only be commercially feasible as a gas export operation, probably in the form of liquefied natural gas (LNG). In the absence of a compelling alternative, in our view it is more likely than not that project owners would favour development concepts that would involve all extraction, processing and export handling activities being undertaken at sea without requiring any physical connection to shore.

2. Range of potential onshore demand-side options to support other significant new gas discoveries: In the case of both the North and South Islands, relay to shore could support a number of new potential demand-side direct gas and energy transformation development options. The viability of different new-build demand-side options would depend largely on resource scale and delivered gas price. In the North Island there is a risk that relaying a large new gas stream to shore as part of an onshore LNG export development could result in domestic gas prices rising towards import-parity benchmarks, as has been seen in other countries, particularly Australia. This risk is not valid in the South Island as there is no existing gas market and a number of existing low-cost alternative fuel choices already exist, principally coal and LPG. Relay of gas to shore in the South Island could provide a significant new layer to that region's energy markets by adding a new and environmentally friendlier fuel option.

3. Legislation provides basis for engagement over development options: In the event of exploration success, the Crown Minerals Act (CMA) provides for government to engage with project developers towards evaluating and approving a final field development plan (FDP). The CMA specifies that any mining of Crown-owned minerals must be "for the benefit of New Zealand". Although open to interpretation, there is at least the potential for a national benefit test to be applied as part of government approval of a final FDP. Within this there is clearly scope for a natural tension between the standalone commercial test applied by a project's developers and a national benefit test that may be undertaken by government. In any case, compared to a number of other comparable government administrations internationally, the skills and experience that would be required to engage meaningfully with developers in FDP discussions is not currently present within New Zealand government agencies.

4. Policy objectives different between North and South Island settings: We see clear separation in potential public policy objectives that could follow substantive gas-rich exploration success depending on whether a discovery is made off the North or South Island. In the case of a substantive North Island discovery, policy discussion would likely balance economic development with the risk of disturbance to existing energy markets and, in particular, the risk of an import parity-induced gas price shock to that region. Experience of other countries, particularly Australia, suggests that policy programmes and responses would need to be considered with great care. In the South Island the focus would likely be much broader and centre on options to maximise overall benefits to NZ.

5. Significant downside risk to existing North Island gas market: Offsetting upside-themed discussion of potential benefits and opportunities that could accompany a substantive new gas discovery, we also consider there to be increasing downside risk in the North Island gas market. In particular, the potential near- to medium-term risk of losing significant demand-side capacity from the electricity generation sector would, if realised, result in a substantial reduction in market size and a commensurately material increase in market concentration. Supply-side downside is also a risk, although in our view to a significantly lesser extent currently than is the case than with the demand-side. More likely is a scenario where reserve replacement continues to remain the main near- to medium-term supply-side theme.

Summary

- International agencies are of the view that gas will play a significantly greater role in the future global energy mix. Recent reporting from the Intergovernmental Panel on Climate Change (IPCC) has also highlighted the role of gas as a transitionary fuel for replacing oil- and coal-based alternatives towards meeting climate change policy objectives.
- Recent experience in overseas markets, particularly in North America, has demonstrated the dramatic extent of economic, social and environmental benefits that increased gas supply can deliver. Equally however, experience in other regions, including in Australia where a major expansion of the supply-side of the sector is resulting in substantially higher local energy prices, provides a basis for caution.
- Other more mature markets are also increasingly adopting technology that is changing the nature of direct gas use. The clearest example is liquefied natural gas (LNG). Until recently LNG has been deployed to trade gas between markets, however increasingly LNG is being consumed directly within markets. LNG may now be viable down to very small operations, providing new market opportunities along the full length of the scale continuum.
- In both physical and commercial terms, the North and South Islands represent entirely separate gas markets. In gas terms, the two islands may as well represent separate countries. Whereas the North Island has an established and extensive gas infrastructure network that connects a mature market of industrial, commercial and residential users, the South Island is currently entirely devoid of natural gas supply or demand. In terms of potential gas planning, commercialisation and public policy scenarios therefore, the South Island represents a blank sheet of paper.
- A large gas-rich discovery in the South Island could potentially deliver a transformational mix of economic and social benefits to that region. It could also add a significant new and environmentally friendlier layer to the South Island's existing coal- and liquid fuels-intensive energy markets.
- The choice of field development concept in the South Island would be a function of below-ground (resource scale, field profile and physical setting) and above-ground (technology, infrastructure, economics and politics) decision factors. In the event of a substantive discovery, even an initial development would require billions of dollars of investment capital.
- The extent to which national benefits could be maximised from a major new South Island discovery will depend in part on the development concept decided on by the discovery's would-be owners. In general, due to the potential for a material downstream sector to develop, our view is that an upstream field development concept that would involve production being relayed to shore for processing and possible consumption would likely deliver greater national benefits than what would be the case under an offshore-only development.
- Advances in technology mean that, even in the event of a very large gas discovery, there is no certainty that production would be relayed to shore for processing and handling, let alone consumption. In our view, this could deliver outcomes that, while economically efficient, could result in lost opportunities to New Zealand. In the event of substantive frontier basin exploration success, we think there would be a public policy case for considering options for increasing the capture of national benefits beyond what market outcomes alone might otherwise deliver.
- Existing legislation provides government with potentially substantial influence over the design of any field development. However, key government agencies are not currently resourced to engage in such discussions, increasing the risk of development outcomes that could result in opportunities being missed.
- In Taranaki, the benefits of a comparable discovery would likely be less pronounced, but only because the region already has an established oil and gas industry and, therefore, a higher starting baseline. A substantive discovery would still have a material impact and serve to open up a large number of new industrial and commercial options.
- Regardless of its location, a substantive gas discovery would, if relayed to shore, serve to support a potentially broad array of commercialisation options including petrochemical and fertiliser manufacture, transport fuel, industrial heat, electricity generation and reticulated gas. In all cases, delivered gas price would be a key determinant of economic viability.
- Offsetting potential growth scenarios, in the North Island market we see significant downside risk to the status quo. If realised, the implications for existing market size and structure are substantial. To manage this, efforts to broaden the existing Northern gas market should be progressed irrespective of any potential supply-side growth. A number of direct gas and energy transformation options exist to achieve this, however most would rely on securing dedicated long-term tranches of gas, which in the current market context is difficult.
- In our view, urea and transport fuel are conceptually the gas deployment options that present the strongest fit with NZ's commercial and situational context. Further work is required to understand the economics and viability of these and other options, however we consider that each could already be viable on the basis of existing and known resources alone.

Background

The gas industry remains a key contributor to NZ's energy supply and economy. After a period of substantial change to existing market arrangements during the mid-2000s which saw the gas market contract materially, in recent years there has been a strong rebound in both supply- and demand-side capacity. The domestic market is now supplied from 15 producing fields and in recent years has shown growth in terms of volumes, pipeline kilometres and connections.

The industry appears poised for significant further expansion. Investment in exploration in NZ is at an all-time high, with up to 100 wells potentially to be drilled over the next couple of years. This is in the context of a rapidly increasing role for gas internationally and a strong growth outlook in global supply and demand. A large new discovery would present NZ with a number of issues, opportunities and challenges. Much has changed since the country successfully set out to exploit the Maui field, including the potential for gas supply to be extended beyond the Taranaki region for the first time. There is also a possibility that new production could be exported in its entirety as LNG, unless there is a compelling case made otherwise. There is a spectrum of possible scenarios for how development of the next significant NZ gas discovery could unfold. Although post-discovery planning and development timeframes could easily take 5-10 years before first production, the critical investment and policy decisions on which commercialisation could proceed would be made very much sooner.

There is much we can learn from local and overseas experience and it is important that stakeholders have a baseline of starting information and understanding in the event of a large gas discovery. To that end, this paper serves to discuss the key first-principle commercialisation issues and opportunities that NZ would need to consider in the event of substantive, gas-rich exploration success. Towards informing this paper, a number of discussions and interviews were undertaken with industry players from different parts of the NZ energy supply chain.

Gas: the global equation

A number of international agencies have forecast an extended period of growth in global gas supply and demand. The International Energy Agency has signalled a "golden age of gas" where rising supply is met by strong demand growth. In North America, where since the mid-2000s when the deployment of horizontal directional drilling and hydraulic fracturing has enabled the bringing-to-market of relatively cheap and abundant new supplies of unconventional shale and tight gas, a structural shift in energy production and consumption is already well underway.

Economic growth and energy prices present a strong negative correlation: the higher that energy prices are, the lower that economic growth will be, and vice versa. It is unsurprising therefore that economists are crediting low North American gas prices for supporting US economic growth during a period when oil indices have averaged around US$100 per barrel. Employment in the already deeply mature US oil and gas industry has risen by more than 40% since 2007 (the same year the GFC commenced), compared to the overall US economy which declined 3% over the same timeframe. Increased domestic production since 2008 has seen US oil imports fall by around 50%, delivering a commensurately dramatic improvement in US balance of payments. By 2020 the IEA forecasts that the US will become a net exporter of gas – a status it has not held since 1957.

The de-linking of oil and gas price indices in the North American market since around 2005 has seen a number of players, including at least two of the largest incumbent companies in the New Zealand sector (Todd Energy and Methanex), take steps towards building or re-locating new petrochemical processing plant in North America to take advantage of the gas-oil price arbitrage on offer in that market.

The environmental benefits of increased gas supply are also rapidly becoming evident. Again this is no more the case than in North America where gas is increasingly displacing coal in heavy industrial applications. Over the past decade coal-fired generation has fallen from more than 50% of total production to around one-third while gas-fired generation has doubled its share from 17% in 2003 to 34% in 2013. With gas the cleanest burning of all fossil fuels and gas-fired generation being up to 70% cleaner than its coal equivalent, the result has been a dramatic reduction in greenhouse gas emissions in one of the world's most carbon-intensive economies, falling to levels last seen in the early 1990s. There is a strong argument to suggest that, in respect of Kyoto Protocol targets, technology has achieved significantly more than politics towards reducing US carbon intensity.

Similar but to date less dramatic trends are evident in the transport fuel markets where gas-based alternatives to liquid fuels are also seeing strong growth, delivering similarly positive microeconomic, macroeconomic and environmental benefits.

The global gas expansion story however is not without its fishhooks. In Australia, a A$65 billion wave of capital investment in new-build LNG export capacity on Curtis Island near Gladstone is transforming the East Coast gas market, which serves more than 85% of the Australian population. The effect is one of internationalising that market, transforming it from a state of internal subsistence where domestic supply meets domestic demand, into a structural net-export situation where local gas users are competing directly with sellers supplying the global LNG export market. Once the last of the three plants currently under construction is commissioned in mid-2015 the East Coast gas market will have nearly quadrupled in size in little more than a year. Although none of the plants is yet operating, price indices have already rapidly ascended towards LNG benchmarks. For major local users, energy input prices have at least doubled in the space of just a couple of years, from A$2-4/GJ in 2009/10 to A$6-8/GJ today. With gas being the main industrial fuel in the eastern region, the competitiveness of the Australian manufacturing sector is suffering at the hands of dramatically higher input costs.

Gas: the local equation

NZ's natural gas industry was built out of the Maui and Kapuni gas-condensate discoveries. Although the onshore Kapuni field was the first to be discovered (in 1959) and commissioned (1969), it was the discovery (1969) and arrival to market (1979) of the much larger Maui field that defined the subsequent development of the local sector. A central aspect of the arrangements that ultimately saw each of Kapuni and Maui developed was deep involvement by the Crown by agreeing to assume much of the commercial risk involved with placing very large quantities of gas into a then non-existent NZ gas market. To establish a demand base, a substantial network of midstream (high pressure and local distribution pipelines) and downstream (power generation, petrochemicals and fertiliser) infrastructure was built. A central component of Maui's commercial arrangements was agreement between gas seller (the Maui Mining Companies, including at that time the Crown with a 50% interest) and buyer (the Crown) to a low base gas price that was prescribed to rise at only half the rate of annual inflation over the 30-year term of the contract. Much lower demand than was forecast during the 1980s and 90s saw the Crown (as buyer) agree to further contractual concessions with the result that large volumes of very cheap gas remained in the market until the early 2000s.

The abundance of Maui gas and long-term Maui and Kapuni gas supply contracts that featured low delivered gas prices served to substantially reduce the incentives for companies to explore for oil and gas in NZ. This situation changed in the early 2000s as Maui entered its production decline. A field determination in 2003 served as the catalyst to redefine the commercial arrangements to apply to remaining Maui reserves and marked the start of a period of structural upwards gas price adjustment. At around the same time, in what was then a market context dominated by fears of supply-side shortfall, the Pohokura and Kupe gas-condensate discoveries were each being progressed towards development. The developers of each field were able to secure long-term gas sale agreements containing gas tariffs at least double existing benchmarks and imposing very much more onerous non-price uplift obligations on gas buyers. For major gas users, dominated by electricity generators (particularly Contact Energy and Genesis Energy) petrochemical manufacturers (Methanex and Ballance Agri-Nutrients) and major industrial customers (NZ Steel, Fonterra, Refining NZ et al) this adjustment phase was both very difficult and very expensive. A number of these players took steps to reduce their gas use with the result that the gas market contracted very sharply over the 2001 to 2006 period. The more recent development of the onshore Mangahewa field has underwritten a sharp recovery in wholesale gas market volumes, albeit due almost entirely to Methanex re-starting previously idled capacity at its Motonui and Waitara Valley sites.

Within this background, the NZ gas sector today is defined by a small number of dominant physical and commercial characteristics:

- The NZ market for natural gas is in fact a North Island-only market. There is no existing gas supply into the South Island.
- Although Methanex does provide a significant export outlet for manufactured product, NZ remains the only country in the OECD that does not have existing direct gas market interconnection to that of another nation or nations, either by way of a cross-border pipeline or LNG import/export. In energy terms therefore, NZ's gas market remains one of structural internal equilibrium.
- Although now in parts more than 40 years old, the transmission infrastructure that serves the North Island market has been well maintained and remains in generally very good condition.
- Existing major gas demand-side installations (examples being the Huntly power station, petrochemical plants, gas-fired electricity generation and a number of major industrial sites) are generally mature and typically operated, at least in part, on a short-run cash margin basis.
- After completing its plant restart programme, Methanex is expected to be running near full capacity during 2014, with the consequence that the wholesale gas market will likely become topped-out on existing demand-side capacity. If and when this occurs, Methanex would account for 40- 45% of the total NZ gas market. Further organic market growth options beyond Methanex appear limited. In recent years, thermal generators have moved increasingly towards relegating CCGT to a mid-merit hydro-firming role, with a consequent reduction in gas demand.

Determinants of gas commerciality

Oil and/or gas field commerciality is a concept that is often misunderstood as binary: either an exploration well strikes pay and is therefore a success and reveals a resource that will always be commercial, or it is a failure and will always be plugged and abandoned as a dry hole. In reality, exploration outcomes sit on a continuum bounded by two extremes. At one extreme is the type of world-scale discovery that would transform even the largest of exploration companies (as a reference point, the South Pars/North Dome gas-condensate field in the Persian Gulf, is considered to be the world's largest conventional gas discovery, thought to contain around 1,800,000PJ of gas - equivalent in size to around 450 Maui fields). At the other extreme is a well that fails to encounter even the target geological formation, let alone reveal oil and/or gas shows.

It is common, even in New Zealand, for discoveries to reveal significant oil and gas quantities but not to be developed due to the economic case to do so not being strong enough to reward the capital and risk outlay that the would-be developers would be required to assume if they committed to developing the field. The commercial decision not to develop such discoveries represents the difference between a technical discovery (where a well delivers to prognosis by encountering the expected formation(s) and revealed hydrocarbon charge) and a commercial discovery (where the resource encountered is of sufficient scale and market conditions of sufficient attractiveness to justify a positive development decision). Examples in New Zealand include the offshore Karewa field (discovered in 2004 in the northern Taranaki basin) and the onshore Kauhauroa field (discovered in 1998 in the onshore East Coast Basin). Even the Kupe gas-condensate field, which was discovered in 1986, was deemed non-commercial for more than 20 years. It was not until 2006 when a decision to develop Kupe was made that the field's owners agreed that the field was commercially viable to develop. Kupe now forms an important cornerstone to the North Island's gas supply network, and is one of the upstream sector's most valuable assets.

The technical/commercial success continuum is also evident in NZ frontier basins. In the offshore Canterbury and Great South basins where Anadarko Petroleum and Shell are leading work programmes on behalf of joint ventures, 14 wells have been drilled since 1970. Of these, five were unsuccessful and registered no oil, condensate or gas shows, a further six (including Anadarko's recent Caravel-1 well) registered oil and/or gas shows but not flows, and two (Clipper-1 and Galleon-1) yielded material hydrocarbon flows and were declared as technical gas-condensate discoveries. None have been developed.

Decisions regarding whether or not to develop discoveries are usually extremely complex and comprise a great many decision variables. We think of these variables as being able to be classified as either below-ground or above-ground:

Below-ground factor	Generic context	NZ context
Geology	Formation characteristics (faulting, closures etc), permeability and porosity, which can only be accurately gauged and modelled by surveying and/or drilling target formations.	Moderate understanding in Taranaki Basin. Very shallow or no understanding in frontier regions where drilling and/or seismic surveying have not been undertaken.
Hydrocarbon profile	A raw wellstream that has a liquids (ie oil, condensate and LPG) component is generally more valuable than a gas-only wellstream. A high CO_2 content increases handling complexity.	New Zealand wellstreams tend to be gas-rich, both in the Taranaki Basin and, as far as is known, elsewhere (eg Canterbury Basin). High CO_2 content also a common feature.
Physical setting	Offshore exploration and production is very much more expensive to undertake than onshore and technical challenges more difficult to overcome.	Largest NZ prospects are offshore. NZ's seabed is known to be complex, particularly in transition zones from deepwater to shoreline. Pipeline and relay issues would likely prove challenging to address and overcome.

Above-ground factor	Generic context	NZ context
Political	Political factors impact project commerciality both directly (via fiscal terms of royalty and tax rates) and indirectly (policy and regulatory).	NZ rates very highly in both generic favourability surveys and in international oil and gas-specific benchmarking surveys.
Technology	Identify and execute the best field development plan. Advances continue to deliver dramatic improvements in success and recovery rates.	NZ a technology-taker, supported by presence of a number of large multinational companies already present in NZ sector.
Market context	Local market factors including access to infrastructure and the existing presence of functional wholesale energy markets.	North Island mature but capacity-constrained wholesale gas market. South Island absent of a natural gas market of any kind.

Generic gas commercialisation options

Typically significant gas contents within NZ's known hydrocarbon systems requires explorers to plan for the likelihood of a gas-rich resource in the event of exploration success. While gas-reinjection is usually a viable option and can enhance oil recovery, gas monetisation is preferred to support commercial viability. In generic terms, gas can be commercialised in one of two ways:

1. Direct use: Applying gas directly as a fuel, either instantly (eg for residential, commercial and industrial gas heating) or following temporary storage (typically involving gas compression or liquefaction). CNG and LNG are both forms of direct use. CNG enjoyed a period of strong growth as an automotive fuel during the 1980s on the back of widespread government subsidies, however consumption is now at negligible volumes. LNG does not currently feature in the NZ market.
2. Conversion: Using gas as a feedstock to convert into another form, often with other feedstocks and/or industrial catalysts. Examples include electricity generation, petrochemical manufacture and gas-to-liquids (GTL) options. Conversion accounts for most of the NZ gas market concentrated largely to electricity generation and petrochemicals (methanol and urea).

The importance of scale, technology and corporate materiality

The aggregating of below-ground and above-ground factors enables companies to reach a view on the significance of a new discovery to its business. This internal test for materiality is a relative (rather than absolute) assessment that is specific to each project and each corporate. For example, for a company of the global weight of Shell, even a discovery that is large in a NZ context may not be of sufficient scale, versus other projects in its global portfolio, to justify the substantial investment of capital and labour that would be required for it to lead the commercialisation of that discovery. For smaller players however the materiality test would likely be very different with the result that the same discovery could well be assessed to justify its deployment of corporate resource.

It is therefore too simplistic to conclude definitively that a discovery in the Canterbury or Great South basins would need to be of world-scale proportions (perhaps >10,000PJ, or the equivalent of more than two Maui fields) for it to be developed. Technology advances are serving to improve the economics of smaller discoveries and, as a result, increase the likelihood of being developed. In particular, the emergence of floating LNG (FLNG) technology to monetise gas discoveries that would previously have been uncommercial due to their lack of scale and remoteness from market, is changing the face of the global sector. When approved, Shell's Prelude project, currently being developed on Australia's northwest shelf, was the world's first FLNG project. Once operating in 2017, all field production activities will be undertaken from aboard a 488m long FLNG vessel moored permanently 200km off the Australian coast. The vessel when completed will be the largest floating structure ever put to sea and will be capable of producing 5.3 million tonnes per annum (mtpa) of natural gas liquids comprising 3.6mtpa of LNG, 1.3mtpa condensate and 0.4mtpa of LPG. The field that will feed Prelude's FLNG vessel is estimated to house between 3,000 and 5,000PJ of recoverable gas – very comparable in size to the Maui field – and produce at a rate of 175 to 200PJ pa plus condensate and LPG. This is also comparable to Maui's production profile when it was operating at peak levels in 2000-01.

A number of other major operators are advancing their own FLNG plans, with the most advanced being Malaysian company Petronas which has committed to two FLNG vessels, with capacities of 1.2mtpa and 1.5mtpa, for deployment to produce from separate gas fields in Malaysia. Although FLNG projects announced to date have been in relatively shallow water settings, there appears no technical reason for why FLNG could not in future be deployed to deepwater settings in the same way that floating production storage and offload vessels (FPSOs) are increasingly being deployed to deepwater environments to produce from offshore oil fields.

The two key advantages of FLNG are (1) mobility (unlike traditional land-based LNG installations, FLNG vessels can be moved and re-deployed to other sites as fields deplete); and (2) cost (construction is undertaken in a highly controlled environment providing much greater control over build costs and timelines). The benefits of these features are evident when set against the fleet of onshore Australian LNG mega-projects currently under construction which have each suffered severe time and cost overruns. Despite the attractions of FLNG, it is likely that, for the near-term at least, conventional land-based LNG installations will likely remain the preferred development option for very large offshore discoveries where processing scale is fundamental to field economics. This is the case in Mozambique where wildcat exploration, led initially also by Anadarko, has revealed a new world-scale conventional gas region. The scale of resource, estimated currently at around 200,000PJ (approx. 50 Maui fields) but with the likelihood of substantial further upside, involves plans for new-build global-scale onshore LNG liquefaction facilities, initially rated to 50mtpa. Looking ahead however, even with large offshore gas developments it seems likely that the sector will move increasingly towards deploying FLNG fleets in place of development concepts that would otherwise involve building large-scale onshore coastal facilities.

A notable trend over the past half-decade has been the emergence of very much smaller LNG development concepts. On the supply-side, micro- or mid-scale LNG liquefaction is serving to improve the development economics of smaller and/or remote gas fields. On the demand-side, the emergence of localised small-scale applications is increasingly resulting in LNG being deployed towards local market consumption instead of simply as a means of trading large quantities of gas across international borders. The result is the emergence of new applications and markets for gas, particularly in the form of LNG and CNG as road transport fuel. For users, the investment cases for LNG and CNG projects centre on substituting for liquid fuels (diesel or petrol) and distil to balancing higher initial capital costs with significant ongoing fuel cost savings (gas-based transport fuel is typically cheaper than liquids-based petrol and diesel fuel) and environment (gas combustion produces far fewer greenhouse gas emissions and particulates into the atmosphere than liquid fuel) benefits. Small-scale LNG projects being advanced in other countries include:

- A concept plant currently under construction in Indonesia will comprise multiple 0.5mtpa modular liquefaction units that will produce LNG for supply into the Asian seaborne export LNG market. The format will enable the commercialisation of a comparatively small (2P reserves approx. 175PJ) and remote gas field that would otherwise not be developed.
- In Australia developers are assessing micro-LNG concepts as a means to monetise very small and/or remote discoveries. One such project will see a modular LNG liquefaction unit installed atop a small (2P reserves approx. 20PJ) to liquefy 13TJ/day of production into 56,000tpa of LNG. Produced LNG would be deployed towards extending an existing LNG and CNG roadside refuelling network to service road vehicles, however could potentially also be supplied directly into LNG export terminals.
- A separate project operating in Tasmania since 2011 services a fleet of 125 LNG-fuelled trucks via a network of six LNG fuelling stations across the island. The liquefaction plant produces 18,000tpa of LNG (equivalent to around 25m litres pa of diesel) from gas sourced from existing Bass Strait gas fields.
- In Canada, in early 2013 Shell commissioned a LNG refuelling station network along the Queen Elizabeth II highway connecting Calgary with Edmonton to service heavy truck fleet customers.

South Island commercialisation options

The South Island has no existing gas market and is absent of either supply or demand. A substantive gas discovery in either of the Canterbury or Great South basins would serve as a catalyst for a range of potential new industrial applications to be considered. These include at least LNG and, depending on whether a new discovery is relayed to shore, other applications including petrochemical manufacture, electricity generation, heat production, GTL and mass-market applications.

Field commercialisation decisions would involve extensive consideration of both upstream and downstream development options.

Upstream options form part of the field development plan (FDP) in which the project's owners identify and evaluate technically and commercially feasible development options by integrating the above- and below-ground factors we have already summarised. Initially, the most important factor would be resource scale, an accurate assessment of which would require 1-2 years of follow-on appraisal drilling and analysis before firm conclusions could be drawn. Once scale has been determined, FDP commercialisation options would be able to be considered in detail.

In the case of the South Island, our generic assessment of the potential upstream commercialisation options along the scale continuum is summarised below.

Gas reserves scale	Potential production	Existing NZ field analogues	Potentially viable commercialisation concepts for South Island offshore discovery
Small < 500PJ	≤50PJ pa	Kupe	Probably none. Cost of commercialising, particularly in deepwater environment, very unlikely to support standalone development economics.
Medium 500-2,000PJ	30-300PJ pa	Pohokura	Smaller-scale (<2mtpa) FLNG. Onshore relay a possibility but deepwater economics likely to rule out viability of smaller fields, particularly if field presents little or no associated liquids stream.
Large 3,000-10,000PJ	200-500PJ pa	Maui	Larger-scale (>2mtpa) FLNG. Shell's Prelude FLNG project is a valid analogue. Relay to shore likely to be viable for LNG and onshore industry.
Very large 10,000-50,000PJ	>400PJ pa	None	World-scale shore-based multi-train LNG liquefaction facility plus supply to onshore gas sector. Multi-vessel FLNG fleet also potentially viable.
Global > 50,000PJ		None	Large shore-based multi-train LNG liquefaction facility plus to supply onshore gas sector. Multi-vessel FLNG fleet potentially feasible, but scalability likely to be a limiting factor.

Past analysis by GNS has indicated that the resource bases of new discoveries in the Canterbury and Great South basins could lie in the 300PJ through 10,000PJ range inferring that, in the event of a significant discovery, FLNG would be the most likely field development concept unless a viable shore-based alternative can be demonstrated.

Downstream options are only relevant to potential FDP concepts that involve a connection to shore (although similarly to FLNG, we note the likely future potential for some downstream options that have traditionally been undertaken onshore, such as petrochemical manufacture, to be undertaken in an entirely offshore setting). For larger discoveries, shore-based LNG would likely be viable on a standalone basis, however whether this option would be superior to a seaborne FLNG alternative would depend on an array of technical and commercial factors. An onshore connection could support the development of a downstream gas sector potentially similar to that in Taranaki, comprising both direct use and gas conversion components. In fact, the potential commitment of large downstream users would likely be a critical factor in the decision making towards a final FDP. In respect of scale, we consider that discrete, technically feasible downstream development options can be grouped as follows:

Scale	Discrete downstream new-build options	Analogue Taranaki plants	Indicative capex
Small <10PJ pa	• Low- to mid-merit electricity generation • Smaller urea/ammonia/nitrogen manufacture • Site-specific heat and industrial applications • Transport fuel (LNG, CNG)	• Fonterra Whareroa cogeneration • Todd Energy Mangahewa peakers • Ballance Agri-Nutrients urea •	<$200m
Mid-scale 10-30PJ pa	• High-capacity electricity generation (eg CCGT) • Larger urea and/or ammonia manufacture • Small/mid-format methanol	• Contact & Genesis CCGTs • Methanex Waitara Valley plant	$200m - $1 bln
Large-scale >30PJ pa	• Large-format methanol • GTL	• Methanex Motunui plants	>$1 bln

For potential downstream project developers, the extent to which any of these options could be progressed on normal commercial terms would distil largely to supply certainty and price. If potential developers can attain sufficient gas supply and price certainty then the likelihood of positive investment decisions is high. The exception to this is in the mass-market space where we would think it highly unlikely that the economics and risk profile of reticulation in a virgin South Island market (on the basis of a high pressure pipeline network connecting to the main urban areas) would be commercially viable on a standalone basis. Other options do exist however that could be worthy of consideration, including that of virtual pipelines to support local-supply LNG or CNG, akin to what operates for LPG in some areas of the South Island.

In respect of gas price, a natural inclination would be to conclude that the economics of supplying the local market would need to provide resource owners with a netback relevant to an export LNG benchmark, which for seller could be argued to represent the opportunity cost of produced gas. In our view however this is too narrow and does not account for the benefits that a significant local demand-side gas user or users could bring to a development. There are a number of examples internationally where new-build LNG, petrochemical and other projects coexist under different pricing arrangements. The presence of existing alternative low-cost supply options in the South, particularly coal, would require that domestic gas be price-competitive to displace existing demand.

Public policy

Importantly, the Crown Minerals Act 1991 (CMA) and the Minerals Programme for Petroleum 2013 requires every application for a mining permit to be approved by the Minister of Energy and Resources. With the FDP being a central component of any mining permit application, the inferred extent of influence that government may have over a final FDP is, therefore, potentially absolute. Under the CMA the Minister must act "to promote prospecting for, exploration for, and mining of Crown owned minerals for the benefit of New Zealand". The extent to which in the case of a significant discovery a formal national benefit test and/or cost/benefit analysis could or would be applied towards approving a final FDP is not clear and is open to interpretation, however the ability of government, through its officials, to meaningfully engage with industry towards discussing and, if appropriate, challenging different FDP options is clearly provided for.

Schedule 3 of the Crown Minerals (Petroleum) Regulations 2007 sets out in detail the FDP-specific information required to be submitted with a mining permit application. Our view is that NZ government agencies involved with the oil and gas sector locally are not currently resourced to engage with the necessary confidence on FDP matters that would likely follow a major new frontier basin discovery. Even in the case of smaller or even onshore developments, the ability before and during the mining permit application process to be able to refer expertise internally would be valuable towards encouraging discussion among stakeholders and contributing to potentially stronger outcomes (on both commercial and national benefit measures) than might otherwise be the case. Government would also hold the option of undertaking a standalone cost/benefit analysis towards supporting more explicit policy options to address national interest objectives. International experience would be important towards informing cost/benefit analysis of various options (for example, West Australia's experience with domestic gas reservation policy), however any such steps would need to be confirmed before a mining permit is awarded and a development committed to by its owners.

North Island market commercialisation options

We have noted the North Island as a mature gas market with an extensive distribution network but a demand-side concentrated to a small number of large industrial users primarily in petrochemical manufacture (including urea), electricity generation and industrial heat applications. Methanex is by far the largest single user and after completing its recent restart and turnaround projects would now we estimate account for 40-45% of total gas market volume.

In the case of a medium or large discovery (as we defined in the table on page 7) a FLNG development concept may also be preferred by developers for the same reasons we have noted. If however FLNG is assessed as unviable and assuming that gas production is fundamental to field economics (ie gas reinjection is not technically or commercially feasible) in our view for a large new gas-rich discovery to be commercialised there would likely need to be substantive new onshore demand-side capacity added to underwrite an upstream development. In commercial terms this would require the development of new large-scale gas-dependent downstream plant and a commensurate commitment by plant developers to a long-term gas sale agreement (GSA) to support the upstream investment.

To a significant extent therefore, the potential onshore commercialisation options identified in respect of the Southern market, as summarised in the table on page 8, also apply to the Northern market.

Relevant past analogues in the Northern market that have seen upstream and downstream asset developers undertake to implicitly cross-underwrite each other's projects include the commitment in 2004 by Genesis Energy to long-term gas purchase agreements with its fellow Kupe partners to fuel a new-build 385MW combined cycle power generating unit at Genesis's Huntly site. Another saw a commitment by Methanex in 2012 to a long-term GSA with Todd Energy to provide feedstock to Methanex's two restarted plants from Todd's undeveloped Mangahewa gas-condensate field. These arrangements served to underwrite the respective Kupe and Mangahewa development decisions, for an aggregate ~$2bln in upstream investment capital. Genesis and Methanex's downstream components added a further ~$1 bln of investment capital.

Downside risks to Northern market load growth options

Conditions in some domestic energy markets mean that the likelihood of some of the more obvious new build options being advanced towards commerciality is low. This is particularly the case with electricity generation where, unless there is a significant fall in wholesale gas prices, in our view market conditions make it unlikely that standalone gas-fired electricity generation would find favour as a marginal new-build plant option before at least 2020 (although we acknowledge that there may be a stronger commercial case for integrated upstream+downstream players). In fact, the owners of at least three large existing CCGTs and cogeneration units have signalled they continue to assess the viability of existing assets, placing at risk potential gas fuel demand capacity of up to 70PJ pa. Very much related to this is the ongoing risk of full or part closure of the Tiwai Point aluminium smelter. If Tiwai Point was to close in full, this would result in 5,000GWh of ultra-low-cost (on a short-run basis) production becoming available to contract in the wholesale electricity market. This would inevitably squeeze highest-cost generation from dispatch, being coal-, gas- and diesel-fired. The potential displacement of 5,000GWh of thermal generation approximates 30-40PJ pa of gas-equivalent load.

Similarly, another consideration is the relatively advanced age of much of the Taranaki region's industrial stock. As a result, with some new-build options we have identified, positive investment decisions could involve replacement of existing plant and therefore load substitution rather than outright load growth. In respect of net impacts, new plant build could indeed eventuate, but on a net basis growth in sector gas load may only be marginal.

Smaller-scale commercialisation options

The options we have focused on centre on a scenario where a substantive gas discovery is made that results in significant new gas volumes being able to be contracted to support new project development. We do consider there to be a number of smaller-scale options to increase downstream gas demand and, therefore, to increase (albeit with a lower direct impact) the likelihood of field commercialisation. While in the Northern market such options would be unlikely to individually underwrite the development of substantive new fields, they could serve to support the bringing to market of smaller fields and/or marginal gas which would serve to deepen the market. Of these, smaller-scale new-build urea (requiring perhaps 5-10PJ pa of gas) and LNG (potentially scalable to almost any micro- or macro-size) appear conceptually the most viable.

Further more detailed analysis is required to assess the potential viability of these options.

Glossary, technical notes

Upstream terms

Hydrocarbon is a term to describe an organic compound consisting entirely of hydrogen and carbon, the majority of variations of which occur in crude oil.

Gas, or natural gas, is a naturally occurring hydrocarbon consisting primarily of methane. The term ‘gas’ does not include LPG which comprises heavier hydrocarbons, primarily propane and butane.

Condensate refers to light hydrocarbon compounds such as pentane, hexane and heptane, that normally exist in a reservoir as gas but, due to underground pressure and temperature being higher than at surface, condense to a liquid form during production.

Oil refers to heavier hydrocarbon compounds comprising mostly alkanes, naphthenes and aromatics. Other organic compounds including nitrogen, oxygen and sulphur are also present, as are trace elements of metals such as iron, copper and vanadium.

2P or P50 or proved plus probable reserves refers to oil and gas reserves that analysis of geoscience and engineering indicate are as likely as not (ie with a 50% probability) to be recovered.

Conventional oil and gas refers to oil and/or gas produced from conventional techniques and methods, generally involving a vertical or near-vertical well that penetrates and drains oil and/or gas trapped beneath a sealing cap-rock in permeable source rock.

Unconventional oil and gas refers to oil and/or gas residing in low-permeability source rock that cannot normally be produced from at commercial rates without specialist drilling (eg horizontal drilling) and/or completion (eg hydraulic fracturing) techniques. Varieties of unconventional oil and gas include tight gas, shale gas, oil sands, coal seam gas, underground coal gasification and methane hydrates.

PJ is an abbreviation for petajoule. In the international oil and gas sector normal convention is to express gas volumetrics in imperial terms (ie cubic feet). In some countries (NZ and Australia included) convention is to express in energy terms (joules). In very broad terms, 1,000PJ approximates 1 trillion cubic feet (1tcf). The Maui field holds around 4,000PJ or 4tcf of gas.

LNG is gas that has been treated through a refrigeration process that cools the gas to -162°c condensing it to liquid form. LNG is 1/600th the mass of gaseous form making it readily transportable by ship or land-based transport to market. At the point of destination, LNG is offloaded and stored onshore and when required reheated to restore it to its gaseous form. Gas is then injected into the local gas distribution network. Major LNG producer/exporters include Qatar, Malaysia, Indonesia and Australia. Major LNG importers include Japan, South Korea and the UK. LNG is not combustible in refrigerated form.

CNG is natural gas that is compressed under pressure to occupy less than 1% of its standard atmospheric pressure enabling it to be stored and distributed, typically in cylinders. CNG can be used in traditional internal combustion engines.

GTL is an abbreviation for gas-to-liquids which describes where a refining process converts natural gas into longer-chain hydrocarbons such as petrol or diesel.

Gas reinjection describes where gas extracted from a field is reinjected back into the reservoir instead of being sold above-ground. Gas reinjection is commonly used to boost reservoir pressure to enhance oil and/or condensate recovery. Generally however producers prefer to sell produced gas to support field economics.

Downstream terms

CCGT is an abbreviation for combined cycle gas turbine.

Industrial heat is a broad term to describe heat produced for industrial process by burning fuel (eg gas, coal, fuel oil) in a furnace or boiler.

Virtual pipeline is a term to describe where the installation of distribution and storage supply chain infrastructure is put in place to supply regions that are not connected by an existing physical pipeline.