# Commercial and policy issues, challenges and opportunities that exploration success in the Taranaki Basin or Great South Basin could present to New Zealand

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enerlytica independence | intelligence | insight

# About this report

OMV with its joint venture co-investors has commenced a major offshore exploration drilling campaign targeting the Taranaki Basin and Great South Basin. Four committed wells will initially be drilled with the likelihood of further wells in the event of exploration success. The programme represents a major new investment of international capital into New Zealand and has potentially major implications for the domestic energy sector.

OMV has engaged Enerlytica to prepare an independent analysis and assessment of the key commercial and policy issues, challenges and opportunities that substantive exploration success in the Taranaki and/or Great South basins could present to New Zealand.

The objective of the analysis is to provide energy sector stakeholders and the wider community with an independent perspective on the implications of the drilling campaign and what exploration success could mean for New Zealand.

The analysis and views presented in this report are those of Enerlytica. OMV has reviewed a draft of the report however the analysis, views and conclusions presented are those solely of Enerlytica.

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Enerlytica counts most of the largest upstream, midstream and downstream energy companies active in the New Zealand energy sector as current clients of its services. Most government and quasi-government entities involved in the New Zealand energy sector are also Enerlytica clients.

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# EXECUTIVE SUMMARY

OMV has commenced a major investment programme that includes a four well offshore exploration drilling campaign targeting prospects in the Taranaki and Great South basins. OMV has also committed to an extended late-life drilling campaign to extend the life of the near-depleted Maui field. In total, OMV and its co-venturers will invest more than $400m in NZ over the next 12 months.

The purpose of this report is to provide energy sector stakeholders and the wider community with an independent perspective on the implications of the drilling campaign and what exploration success from it could mean for New Zealand.

The programme that is now underway represents a defining fork in the road for the NZ E&P sector. Success from it would serve to stabilise domestic fuel availability and, therefore, energy affordability. It would also add a potentially substantial new layer to NZ's tax base and economic growth. If the programme isn't a success however then supply margins are likely to continue to fall with an onward risk of significant demand and GDP destruction as major users with the optionality to do so choose to exit their NZ interests. Of these, it is NZ's largest single energy user – not Tiwai Point but in fact Methanex – which is the most at risk.

## Programme risk

The campaign will see the Gladstone-1, Toutouwai-1 and Maui-8 exploration wells drilled in the Taranaki Basin and Takawhai-1 drilled in the Great South Basin. Gladstone-1 is already underway and is likely to be completed by the end of the current month. The COSL Prospector rig will then relocate to drill Tawhaki-1 before returning to Taranaki to drill Toutouwai-1 and Maui-8.

Each well is likely to present a probability of commercial success of between 15% and 35% and cost between US$20m and US$70m. Committing to a multi-well programme means a greater chance that at least one of the wells will be commercial and able to be developed.

## Commercialisation

What commercial success would mean in terms of resource scale and composition is highly uncertain. Best estimates suggest that the Gladstone and Toutouwai prospects could yield recoverable resource of up to 100 million barrels of oil equivalent (mmboe) while Maui-8 is likely to be considerably smaller at around 20 mmboe.

In the event of a oil- or condensate-rich discovery at either of Gladstone-1 or Toutouwai-1 it is likely that fields would be developed around a floating production, storage and offload (FPSO) concept without a physical connection to shore. A gas-rich discovery at either of Gladstone-1 or Toutouwai-1 would likely be tied-in via an undersea pipeline to the existing Pohokura wellhead platform with production relayed to shore to be processed at the Pohokura production station. Gas would be sold into the domestic wholesale gas market.

Success at Maui-8 would be tied-in to the Maui-A platform and production relayed to the existing onshore Maui production station at Oaonui. Tawhaki is a special case. Due to its remoteness from existing markets and its potential scale, a discovery at Tawhaki would likely be developed as a remote sea-based operation irrespective of whether the resource is liquids-rich or gas-rich. A liquids-rich resource would likely be developed as FPSO and a gas-rich resource around a floating liquefied natural gas (FLNG) concept. Indications are that a success case could involve a recoverable resource of between 500 mmboe and 1 billion boe. This is comparable in scale to the Maui field which to date has produced more than 900 mmboe of condensate, gas and LPG.

## Stakeholder returns

If successful, the return on investment for the programme's stakeholders would be substantial. This is particularly the case for the Crown which would benefit from the royalty and corporate tax income streams that development would generate without being required to contribute any of the up-front development capital that the project's equity participants would be required to fund. Largely because of this, the present value (PV) of the income stream the Crown could expect to receive from a development is broadly triple what equity investors could themselves expect.

For unrisked, success-backed developments of the Taranaki Basin prospects, the PV of direct Government take is assessed to lie in a range of $512m (Maui-8) to $1.6 billion (Gladstone and Toutouwai). The outlier however is Tawhaki where, due to its scale, the assessed unrisked PV of Government take totals $11.6 billion. Royalty and tax receipts are made directly to the Crown's general fund from where the funding of core Crown services including health, education, welfare, housing, law and order, Working for Families contributions, Government Superannuation Fund contributions and operating the public service are made. The value-equivalent of a development at Tawhaki alone could approximate the annual cost to the Crown of funding the entire NZ education sector.

Government take estimates do not account for the secondary macroeconomic benefits that one or more developments would deliver including adding new and highly skilled jobs to the regions, higher export receipts and therefore balance of payments benefits, higher GST and PAYE tax bases, a stronger currency and higher economic growth. Past independent analyses of comparable projects suggests these benefits to be at least as valuable as the primary benefits to Government Take.

### Policy considerations

The programme comes at a time of significant political, regulatory and commercial change in the NZ exploration and production (E&P) sector. The Government's April 2018 announcement of its decision to stop granting new offshore exploration permits with then immediate effect came as a deep shock to energy sector investors. A number have since exited their NZ interests at least in part due to the perceived increase in country risk that NZ now presents.

With the Government having committed to further fundamental reform of existing regulatory arrangements with to date only tacit indications of the extent and scope of such change there is currently deep uncertainty as to what the future rules of engagement will be. Assurances provided by the Government to industry in the wake of its April 2018 announcement that "all existing permit rights remain intact" is of no material commercial significance given that a successful explorer would need to go through the process of applying for an entirely new permit to be able to bring a discovery into commercial production.

The direction of climate change regulation is another area that could prove problematic in the case of exploration success. A large development would be likely to incorporate carbon capture and storage (CCS) into its field development plan (FDP) which would reduce fugitive emissions to minimal levels, however it is unclear whether even this would serve as sufficient mitigation against the future potential for consideration of climate change impacts to be accounted for in regulatory processes and decision making.

Moreover, despite international consensus among major multilateral energy agencies and NGOs that CCS is a critical enabler of decarbonisation, it is not currently explicitly accounted for in NZ law and there currently appears little appetite from Government to prioritise it.

### Security of physical and economic energy supply

Additional again to direct and indirect stakeholder and economic benefits is the support provided by (in particular) gas to security of domestic energy supply. Two significant unscheduled outages at the Pohokura field during 2018 have focussed the energy sector's attention on gas system deliverability. Gas typically contributes 20-25% of primary energy supply and is an essential fuel and/or feedstock to the petrochemical, electricity generation, industrial, commercial and residential sectors. Gas also continues to provide critical support to the electricity system to cover the intermittency of renewable fuels – particularly water, the wind and the sun.

NZ has not had a new gas discovery since 2006 and the supply-side of the national portfolio is under increasing singular and collective pressure. The 50-year old Kapuni field and 40-year old Maui field are each deeply mature and nearing the end of their economic lives. More recent additions have either passed (Kupe) or are approaching (Pohokura and multiple others) the end of their production plateaus ahead of deliverability decline.

The supply constraints experienced during 2018 have continued into 2019 and are likely to continue again into 2020 and beyond. Spot and forward gas and electricity markets have factored this and are indicating pricing >80% higher than pre-2018 levels. Increases in the wholesale cost of energy are being passed through to end users including households which can expect their energy bills to increase materially in 2020.

Gas users exposed to deliverability constraints have had no option but to seek alternative supply lines where they are able. Of those, Genesis Energy is the largest and is able to substitute gas for coal to support the availability of its Huntly power station. The availability of domestic coal is however also constrained which has left Genesis with little option but to buy large volumes of imported coal from Indonesia to cover its commercial position and protect security of electricity supply. With coal imports that NZ Steel also brings into the country to supplement insufficient local supplies, the result is that over the past year NZ has imported more than one million tonnes of thermal coal – and with that more than two million tonnes of $CO_2$ – into the country to cover domestic fuel supply shortages.

### Stabilising energy markets

Stabilising the domestic gas market – and therefore also the domestic electricity market – requires the commitment of substantial reinvestment capital to extend the lives of existing gas fields and, ideally, bring new fields to market. The decline in international investor interest in NZ's E&P sector makes the challenge of committing risk capital to NZ now much more difficult to justify than it was prior to 12 April 2018.

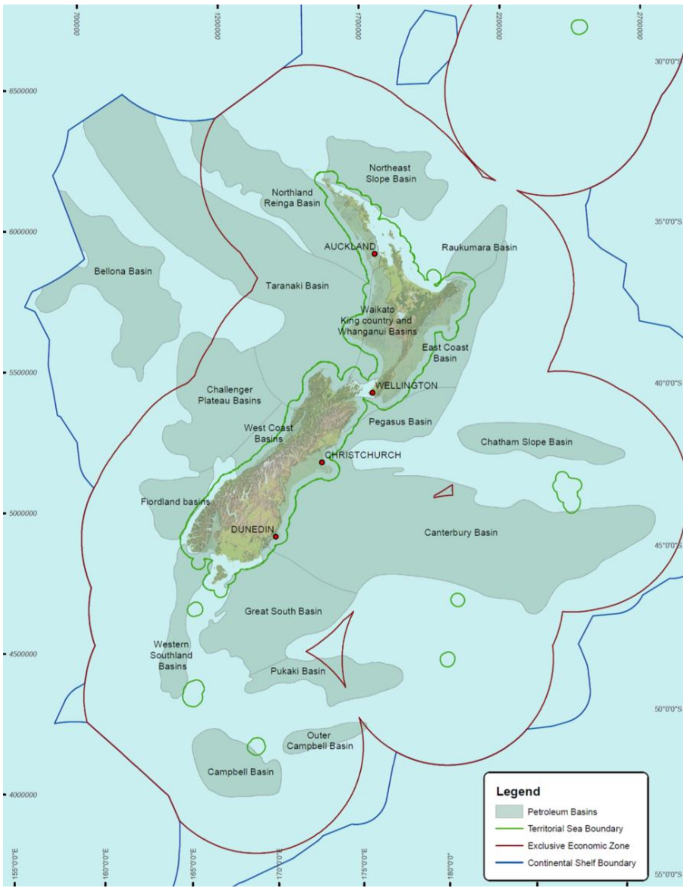
# 1. BACKGROUND

## NEW ZEALAND

Due to the remoteness of its landmass, New Zealand's 5.7 million km$^2$ of territorial waters occupy an area larger than Europe and is one of the largest in the world. Within its sovereign territory, 18 sedimentary basins have been mapped. To date however only the Taranaki Basin has successfully been brought to commercial production. Of the other 17, fewer than half have exploration histories of any significance.

Despite the sparseness of activity, each frontier basin to have previously been explored has posted encouraging initial results. Oil and/or gas shows have been registered in every basin that has been drilled, often at significant initial flow rates. All indications to date point to active petroleum systems in and between most basins. Geologically, the potential for further development of the Crown mineral estate is very significant.

**NZ sedimentary basins**




Source: GNS

**E&P activity histories of NZ sedimentary basins**

| Basin[1] | Area 000 km2 | Onshore or offshore permits? | Wells drilled | Producing fields |
|---|---|---|---|---|
| Canterbury | 360 | Both | 14 | - |
| Taranaki | 330 | Both | > 400 | > 20 |
| Reinga | 170 | Both | 4 | - |
| Great South | 130 | Offshore | 8 | - |
| Challenger | 120 | Offshore | - | - |
| East Coast | 120 | Both | > 40 | - |
| Bellona | 80 | Offshore | - | - |
| Northeast Slope | 80 | Offshore | - | - |
| Pukaki | 60 | Offshore | - | - |
| Campbell | 40 | Offshore | - | - |
| Chatham Slope | 40 | Offshore | - | - |
| WKW[2] | 40 | Onshore | 19 | - |
| Western Southland | 40 | Both | 4 | - |
| Raukumara | 36 | Offshore | - | - |
| Fiordland | 35 | Offshore | - | - |
| West Coast | 25 | Both | 21 | - |
| Pegasus | 25 | Offshore | - | - |
| Outer Campbell | 20 | Offshore | - | - |

Notes
1 Ordered by surface area
2 WKW = Whanganui, King Country and Waikato Basins

Source: GNS, Enerlytica

## NZ'S BELOW-GROUND OFFERING

In respect of what it presents to E&P investors, NZ's oil and gas sector can be thought of as comprising two distinct subsets: (1) the Taranaki Basin and (2) frontier basins. Each comprises a number of sub-categories.

### Taranaki Basin

The Taranaki Basin opportunity set can be thought of as representing increasing positions on a risk / reward continuum. Occupying the positions closest to the origin (meaning lower risk and lower reward) are Taranaki Basin onshore plays. This reflects the basin's proven below-ground prospectivity and the above-ground presence of existing infrastructure and markets. This is not to understate however the challenges involved both below- and above-ground with exploring and producing from the Taranaki Basin. While below-ground the Taranaki Basin offers abundant prospectivity, it is also geologically complex and comprises a large number of distinct plays ranging from shallow conventional onshore oil through to deep tight offshore gas-condensate fields. In the North of the basin there is also a biogenic gas play that includes a discovered but undeveloped gas field.

Hydrocarbons are organic compounds that consist entirely of hydrogen and carbon and are the principal constituents of raw petroleum (oil and gas). The origin of hydrocarbons date back millions of years to prehistoric times when dead organic matter became trapped under layers of sediment. As time passed and sediment accumulated to bury the trapped matter under deeper and deeper cover, increasing heat and pressure ‘cooked’ the trapped matter, from which hydrocarbons were formed. Hydrocarbons can reside as a solid (coal), as a liquid (oil or condensate) or as a vapour (as gas). Generally the higher the heat the lighter the hydrocarbon. Some hydrocabon deposits, such as coal, often lie very shallow to the surface and can be easily accessed while others lie many kilometres below the Earth’s surface.

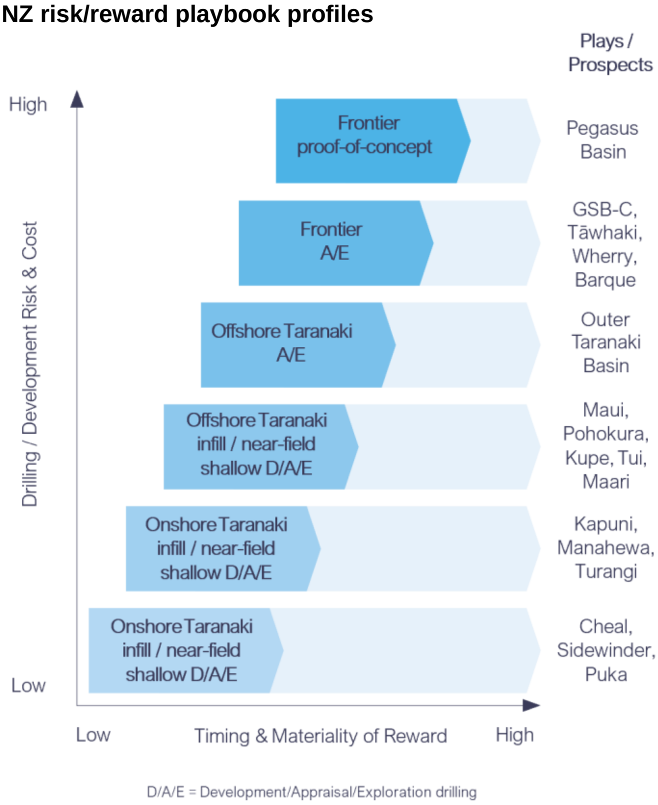
Hydrocarbon deposits are not uniform and tend to contain various other compounds and impurities. Initial processing and separation is usually required to remove impurities and inert matter before product can be sold as a bulk commodity.

The chemical composition of the raw well stream plays a major role in commercialisation decisions. A liquids-rich reservoir can be commercialised as an oil field with lighter hydrocarbons including natural gas and LPG separated off and reinjected back into the reservoir and/or used onsite as process fuel. Gas reinjection can provide the benefit of increasing recovery factors by helping to maintain reservoir pressure which tends to decline as liquids are produced. In the case of a gas-condensate field the LPG and gas cuts can be significant which could allow for them to be separated and sold as distinct product lines.

### Hydrocarbon varietals

| Hydrocarbon | | State | Sales product |
|---|---|---|---|
| Methane | $CH_4$ | Gas | Natural gas |
| Ethane | $C_2H_6$ | | |
| Propane | $C_3H_8$ | Liquid (pressurised) | LPG |
| Butane | $C_4H_{10}$ | | |
| Pentane | $C_5H_{12}$ | Liquid | Petrol, naphtha, jet fuel |
| Hexane | $C_6H_{14}$ | | |
| Heptane | $C_7H_{16}$ | | |
| Octane | $C_8H_{18}$ | | |
| Nonane | $C_9H_{20}$ | | |
| Decane | $C_{10}H_{22}$ | | |
| | ↓ | Liquid / solid | Kerosene, diesel, fuel oil, bitumen, coal |

### NZ risk/reward playbook profiles




Source: Enerlytica

All existing offshore producing fields are located relatively close to the Taranaki coastline and lie in shallow water. The two most distant from the coast – Maari at 80km and Tui at 50km – are each oil fields where all production and export operations are undertaken via separate FPSOs. The Basin’s three other offshore fields – Maui, Pohokura and Kupe – are each gas-condensate fields which connect via undersea relay pipelines to separate onshore production facilities. Maui, Pohokura and Kupe are each important supply components of the North Island gas market and have over the past five years have together contributed around 70% of total market supply.

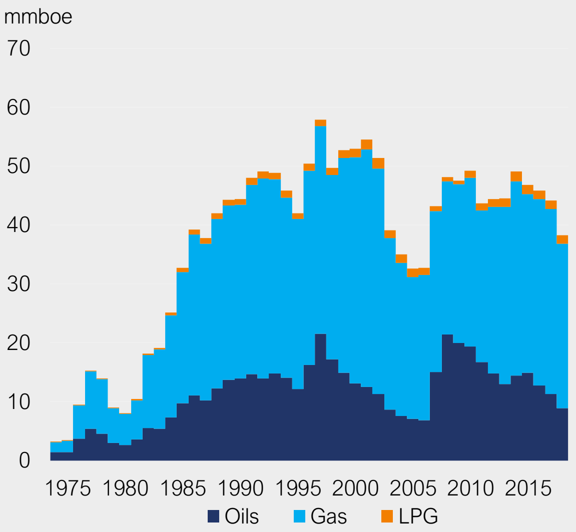
The Taranaki Basin’s oil production history has also been dominated by liquids separation from gas-condensate fields. Over the past five years, the Basin’s six offshore producing fields have accounted for 80% of total NZ oil production.

While more than 20 new fields have been developed since Kapuni entered production in 1970, the Taranaki Basin does not enjoy a high success rate. Including the successful drilling of Maui-1 in 1969, 69 offshore Taranaki Basin exploration wells have been drilled with only five yielding a discovery that have subsequently resulted in a commercial development, inferring a success rate of only 9%. The most recent success was the Tui-1 well drilled in 2003 which led to the development of the Tui field.

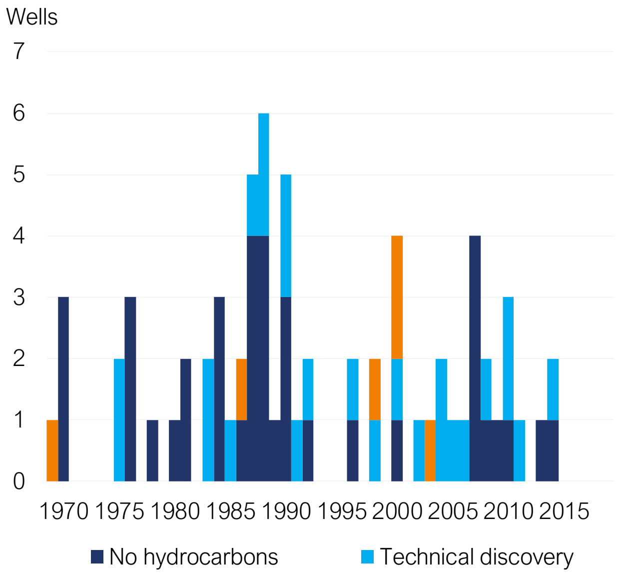
[The Taranaki Basin](#) has a producing history that can be traced to the 1860s when shallow oil was discovered onshore near where Port Taranaki is now located. It was however the discovery of the offshore Maui field by a Shell/BP/Todd consortium in 1969 that transformed the domestic energy sector and supported the development of a large export industry. At the time Maui was one of the largest discoveries in the world however without an existing gas market there was no obvious route to commercialise the field. Maui entered production in 1979 underwritten by government support that included guaranteed gas offtake agreements, the construction of a 1,000 MW dual-fuel coal/gas power station at Huntly, a gas-to-gasoline plant at Motunui, a chemical grade methanol plant at Waitara Valley, an ammonia/urea plant at Kapuni and the North Island reticulated gas network. A central aspect of the agreements was a low gas price intended to encourage gas market uptake.

The 1990s and early 2000s saw users draw heavily from Maui. In the 1990-2002 period, 2,300PJ of gas was produced from Maui at an average 177PJ pa. Boosted by near-capacity operation from Methanex's three plants and the Huntly power station, in 2001 Maui produced a record 204PJ. Until 2003, in a normal year Maui accounted for around three-quarters of all gas market supply. A downwards revision of remaining Maui reserves in 2003 shocked gas users which had been accustomed to low-priced and flexible gas being available as they required it. Negotiations to allocate remaining Maui gas settled on a gas price that was more than double existing levels which with Maui's decline encouraged explorers to invest in exploration and development to bring new gas to market. New gas fields to have since been developed include Pohokura, Mangahewa, Kupe and Turangi.

**Taranaki Basin production history**




**Taranaki Basin offshore exploration wells since Maui-1**




Source: Enerlytica

## Frontier basins

Despite their number and their collective scale compared to the Taranaki Basin, exploration activity in frontier basins has been minimal. By a significant margin the frontier region to have attracted the greatest explorer attention is the Great South and Canterbury basins off the Eastern and Southern coast of the South Island.

Unlike the Taranaki Basin where each commercial discovery has been made in shallow-to-mid water of not deeper than 125m, most frontier basin acreage lies in deep water of >1,000m. The geographic location of some regions, in particular the most Southern basins can also make for more severe weather events and sea-state conditions. These factors require that explorers procure deep-capable drilling and servicing equipment.

As well as deep water MODUs being significantly more expensive than their shallow water peers, the additional distance involved in locating equipment to remote frontier basins makes for higher mobilisation and, therefore, exploration costs. Atop this, the high exploration risk involved makes for an investment proposition that involves a high capital investment with a low likelihood of commercial return.

Because of this it has typically been only major international oil companies with diversity in their production and exploration portfolios that have been involved with frontier basin campaigns in NZ. Companies to have led and/or been involved in past offshore frontier basin campaigns have included BP, Shell, Aquitaine and Hunt Oil.

The Great South Basin is a discrete frontier basin within the Great South-Canterbury Province (GSB-C) which incorporates the contiguous Great South and Canterbury basins. Past exploration efforts have demonstrated each of the basins to house working hydrocarbon systems, however commercial production has yet to be established in the GSB-C province.

The GSB-C has a drilling history that dates back to 1970 and comprises 14 wells. Of these the most positive result was produced from Galleon-1 drilled in 1985 which encountered a 21m hydrocarbon-bearing sand and yielded a gas-condensate discovery which on test produced a material 11.2 TJ/day of gas and 2,240 bbl/day of condensate at a condensate-gas ratio of 200 bbl/TJ. The Clipper-1 well drilled in 1984 also encountered 18m of gas/condensate pay. Of the 14 wells to have been drilled, 10 have encountered hydrocarbons, of which three were concluded as non-commercial discoveries.

The GSB-C has been relatively well mapped with 2D seismic but has had only two 3D seismic surveys completed. The largest 3D survey was completed by OMV and its then JV partners in 2012 acquiring 4,400km$^2$ of data at a reported cost of $50m. Prior to its 3D programme, OMV had acquired 19,000km of 2D data.

Only two of the 14 GSB-C wells have been drilled since 1985 and only one drilled with the backing of 3D seismic. That well, Caravel-1, was drilled in 2014 by a JV led by large US independent E&P company Anadarko Petroleum and yielded moderate but non-commercial gas shows from its secondary target. Anadarko has since exited the permit along with its other remaining interests in NZ.

GSB-C drilling history

| | Well | Spudded | MD | Result |
|---|---|---|---|---|
| 1 | Endeavour-1 | Oct-1970 | 2,741 | dry |
| 2 | Takapau-1 | May-1971 | 1,059 | dry |
| 3 | Resolution-1 | Jul-1975 | 1,963 | dry |
| 4 | Toroa-1 | Apr-1976 | 4,552 | shows |
| 5 | Pakaha-1 | Feb-1977 | 3,389 | shows |
| 6 | Kawau-1A | Jun-1977 | 3,826 | gas/condensate |
| 7 | Hoiho-1C | Apr-1978 | 2,387 | dry |
| 8 | Tara-1 | May-1978 | 4,416 | gas/condensate |
| 9 | Rakiura-1 | Oct-1983 | 2,408 | shows |
| 10 | Pukaki-1 | Nov-1983 | 3,717 | shows |
| 11 | Clipper-1 | Mar-1984 | 4,742 | gas/condensate |
| 12 | Galleon-1 | Sep-1985 | 3,086 | gas/condensate |
| 13 | Cutter-1 | Oct-2006 | 2,930 | gas shows |
| 14 | Caravel-1 | Feb-2014 | 2,692 | gas shows |

## Risk vs Uncertainty

The management of risk and uncertainty is a fundamental aspect of participating and investing in the E&P industry. The two concepts are commonly thought of as being one of the same, which they are not. While nuanced, the distinction between risk and uncertainty is extremely important, particularly when it comes to explorers comparing options to invest financial and non-financial corporate resource towards pursuing growth opportunities.

Risk describes potential future events that can be both discretely identified and readily quantified. As a result, the expected impact of any particular risk can be managed or mitigated. At its simplest, risk can be thought of as flipping a coin - the probability of success is 1-in-2, but so is the risk of failure. In the E&P industry the most visible example of risk is with exploration drilling, where the probability of success can be estimated as can the rewards and costs of success and failure respectively. Explorers have a number of ways to manage their risk exposure including portfolio diversification (spreading risk across multiple permits and/or jurisdictions to reduce exposure to the outcome of a single well or single jurisdiction), partnering (selling-down permit equity to co-investors) and procurement (minimising the cost of necessary equipment by sharing costs with other operators and participants). OMV has employed each of these strategies in ahead of its upcoming NZ programme.

Uncertainty describes potential future events that can neither be discretely identified or readily quantified. In other words, uncertainty is where future events - let alone their probabilities - are not known. Uncertainties are therefore unpredictable and, therefore, uncontrollable. An explorer's ability to manage uncertainty is very much weaker than it is for managing risk, which makes explorers far more sensitive to and aversive of it. Locally, the Government's April 2018 announcement of its decision to stop issuing new offshore exploration permits with immediate effect is a particularly strong example of uncertainty because of the confusing signals that it sent and continues to send to investors and the sharp increase in concern that participants now have towards the security and status of their existing operations and assets in NZ. Beyond this immediate uncertainty, investors that hold exploration permits and have already invested significant risk capital on the assumption of regulatory stability face now far greater levels of uncertainty over the operating environment in which they will make - or not make - future investment and reinvestment decisions.

### Below-ground risk vs above-ground uncertainty

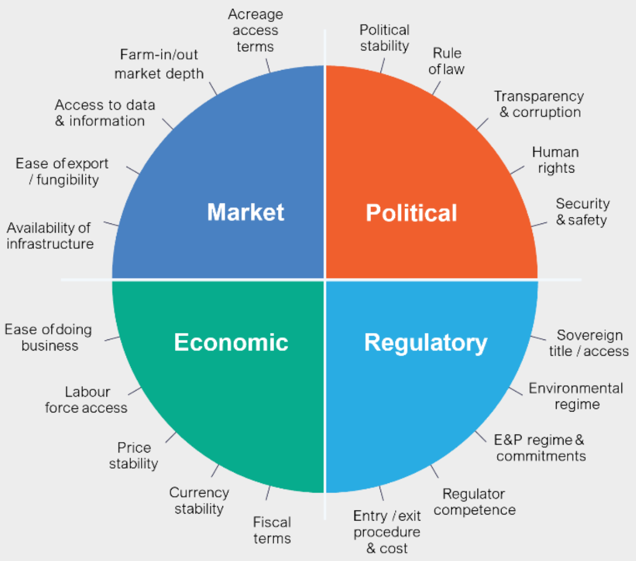
In E&P, the distinction between the concepts of risk and uncertainty can be best characterised by distinguishing between below-ground (risk) and above-ground (uncertainty) settings respectively.

Below-ground risk involves concluding probability-based assessments of key geological aspects of the subsurface being investigated. This requires the input of geoscientists and engineers to analyse data and samples to reach conclusions on the extent of likelihood that key success components of a oil and gas reservoir are present in the target geology. Those components are typically:

1. Source rock – rock charged with organic material which, if heated sufficiently, will generate oil and/or gas
2. Reservoir rock – rock that houses accumulations of oil and/or gas after migration from source rock
3. Migration – the process by which hydrocarbons move between source and reservoir
4. Trap – a configuration of rocks suitable for containing oil and/or gas and which is sealed with impermeable rock, creating a 'trap' for oil and/or gas to accumulate.
5. Seal – impermeable rock layer that forms a barrier which hydrocarbons cannot pass through.

Above-ground uncertainty covers non-technical aspects of the investment case. Areas of uncertainty include political, regulatory, economic and market features of the jurisdiction in which an investment is being considered. Within these are a series of specific uncertainties. Assessing for above-ground uncertainty is less science- and evidence-based than assessing for below-ground risk, therefore requiring a greater degree of judgement in decision making.

**Constituents of investor above-ground uncertainty**




## Above-ground infrastructure & markets

The Taranaki Basin and GSB are polar-opposites in terms of existing oil and gas infrastructure and markets. Whereas the Taranaki Basin has a mature and diverse portfolio of upstream producing infrastructure and a substantial existing network of midstream and downstream assets, the GSB has no existing production and its onshore midstream and downstream infrastructure is focused entirely on importing finished petroleum products from other markets including from Taranaki Basin producers and suppliers.

### Taranaki Basin

While the Taranaki region has a producing history that dates back more than 150 years, it is only in the past 50 years since the development of the Kapuni and then Maui fields that supply-side capacity has been sufficient to support the development of demand-side infrastructure and wider market consumption.

The fields that have been developed in the offshore Taranaki Basin represent one or both of two generic formats:

- Offshore relay – where hydrocarbons are produced from offshore wells and the raw oil and gas stream is relayed to a shore-based production facility where processing and separation is undertaken. Sales products are then dispatched to market typically by pipeline or by road or rail. Maui, Pohokura and Kupe are each examples of offshore relay formats.
- FPSO – where oil and gas is produced from offshore wells and the raw oil and gas stream is received and processed entirely on board a FPSO without any physical connection to shore. Oil is stored in the hull of the vessel and offloaded to shuttle tankers. Gas is typically used to fuel onboard processes with excess volumes either reinjected to the reservoir or flared. The Maari and Tui fields are each FPSO formats.

For relay fields product lines are sold into the North Island wholesale fuels market:

- Condensate is stored onsite before being transported either by pipeline or road to handling and loadout facilities at Port Taranaki.
- LPG is also stored onsite before being dispatched either to local market wholesale buyers or to a LPG export terminal at Port Taranaki.
- Gas is sold into the North Island gas market to petrochemical users (by some distance the largest of which is Methanex), electricity generators and other wholesale gas buyers.

**Taranaki Basin offshore fields**

| | | | | | | Ultimate Recoverable Reserves | | | | Production capacities | | | | Storage | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Format | Field | Operator | WHP? | Discov-ered | Prdn start | Cond. mmbbl | LPG kt | Gas PJ | Total mmboe | Cond. kbbl/day | LPG t/day | Gas TJ/day | Total kboe/day | Cond. kbbl | LPG kt |
| Relay | Maui | OMV | Yes | 1969 | 1979 | 227 | 3,363 | 4,176 | **937** | 25 | 265 | 235 | **66** | 101 | 2.2 |
| | Pohokura | OMV | Yes | 2000 | 2006 | 62 | - | 1,563 | **317** | 18 | - | 230 | **56** | 47 | - |
| | Kupe | Beach | Yes | 1986 | 2009 | 21 | 1,860 | 441 | **108** | 7 | 315 | 77 | **22** | 9 | 1.9 |
| | | | | | | **309** | **5,223** | **6,181** | **1,362** | **50** | **580** | **542** | **144** | **157** | **4.1** |
| FPSO | Tui | Tamarind | No | 2003 | 2007 | 47 | - | - | **47** | 50 | - | 25 | **54** | 700 | - |
| | Maari | OMV | Yes | 1998 | 2009 | 44 | - | - | **44** | 40 | - | 35 | **46** | 600 | - |
| | | | | | | **91** | **-** | **-** | **91** | **90** | **-** | **60** | **100** | **1,300** | **-** |

Reserves as reported by field operators at 1 January 2019

Source: Enerlytica

### GSB-C

Coal is the only indigenous hydrocarbon available in the South Island and underpins most industrial and commercial demand for heat and/or process fuel. All crude (e.g. LPG) and refined (e.g. petrol, diesel, fuel oil) petroleum products are imported either from the North Island or from international markets. Major petroleum-based products such as urea and methanol are also imported either from the North Island or from international markets. There is a mature network of handling infrastructure to service these markets that includes port terminals and storage, roading, depots and a number of small localised LPG reticulation networks.

There is an active local-trade market for black and brown coal which South Island I&C users procure to support their onsite heat raising requirements. The largest coal users are dairy factories, a number of which are of world-scale. Despite this, the industrial sites that do operate in the South Island are comparatively small users of energy. The exception is the Tiwai Point aluminium smelter which is one of NZ's largest consumers of energy, albeit primarily as electricity notionally supplied from the Manapouri hydroelectric power station.

## Government Policy

Companies that choose to participate in the NZ upstream oil and gas sector must comply with a suite of legislation that regulates environmental, safety, market and fiscal aspects of E&P activity. Most of this legislation is generic in that it is not specific to the E&P sector and instead applies to all activity undertaken in NZ irrespective of the entity or individual undertaking those activities.

### E&P-relevant legislation

Acts

- Biodiversity Act 2002
- Climate Change Response Act 2002
- Climate Change Response (Zero Carbon) Amendment Act 2019
- Commerce Act 1986
- Companies Act 1993
- Conservation Act 1987
- Continental Shelf Act 1964
- Crown Minerals Act 1991
- EEZ & Continental Shelf (Environmental Effects) Act 2012
- Fisheries Act 1996
- Gas Act 1992
- Hazardous Substances and New Organisms Act 1996
- Health and Safety at Work Act 2015
- Heritage New Zealand Act 2014
- Income Tax Act 2007
- Marine and Coastal Area Act 2011
- Marine Mammals Protection Act 1978
- Maritime Transport Act 1994
- Overseas Investment Act 2005
- Resource Management Act 1991
- Wildlife Act 1953

Bills

- Climate Change Response (Emissions Trading Reform) Amendment Bill
- Maritime Transport (Offshore Installations) Amendment Bill

## Crown Minerals Act

The article of legislation that is specific to the E&P sector and which defines the overall framework for prospecting, exploration and mining Crown-owned minerals in NZ is the Crown Minerals Act 1991 (CMA). The CMA documents the arrangements under which explorers and producers can be granted access to the Crown Mineral estate and to set the framework by which any economic returns from mining would be shared between the resource owner (the Crown) and the investor seeking to explore for and extract the resource.

The purpose of the CMA in its current form centres on economic development and developing Crown-owned minerals "*for the benefit of New Zealand*". Interpretation of this is made in the Minerals Programme for Petroleum and Minerals Programme for Minerals (Excluding Petroleum) which each state that "*for the benefit of New Zealand*" is best achieved by "*increasing New Zealand's economic wealth through maximising the economic recovery of New Zealand's petroleum resources*."

## The 'offshore exploration ban'

In April 2018 the new Labour-led Government announced that it would, with immediate effect, not issue any further offshore oil and gas exploration permits (referred to hereon in as 'the ban'). The announcement had not previously been signalled, was not part of Labour Party 2017 pre-election policy manifesto and did not feature in any of the coalition agreements between Labour, NZ First and the Greens. It therefore came as a deep surprise to most energy sector participants, particularly those directly impacted in the E&P sector. For OMV, which only three weeks before the ban was announced had itself announced that it had agreed to buy Shell's NZ asset portfolio for US$578m following a two-year negotiation and sale process, the surprise will have been particularly acutely felt.

The announcement was not supported by detailed policy advice which gave rise to an array of public policy issues, the most problematic of which was that moving to reduce access to the Crown mineral estate by removing rights to apply for new offshore acreage was inconsistent with the Crown's obligation under the CMA to promote the Crown mineral estate. To remedy this, the Government decided to amend the CMA to accommodate the announcement.

Instead of the normal Parliamentary process, the Government instructed for a "truncated" timeline with very short public consultation and Select Committee processes. The justification given at the time was that the abbreviated process was necessary to enable the 2018 Blocks Offer exploration acreage marketing round to proceed. The reality however was that the announcement of 'the ban' made the 2018 Blocks Offer irrelevant in the context of the wider implications of the move to cease all future access to offshore exploration acreage.

The Crown Minerals Act (CMA) sets out the legislative framework for the granting of permits to prospect, explore and mine Crown-owned minerals.

Under the CMA, the Crown holds title to:

- all petroleum, gold, silver and uranium, wherever they exist in their natural state;
- almost all minerals that exist on Crown-owned land; and
- certain minerals that have been reserved in favour of the Crown on land which has since been sold.

The CMA came out of four existing pieces of legislation: The Petroleum Act 1937, The Mining Act 1971, The Coal Mines Act 1979 and The Iron and Steel Industry Act 1959.

Any exploration or mining of the Crown Mineral estate requires Government approval. A condition of a mining permit is that the permit holder pays the Crown a royalty for the right to extract oil and gas from the Crown mineral estate. Calculation of the royalty payable depends on when permits were awarded. Many older permits are on legacy arrangements that date back to when the respective permits were first awarded – for example 1970 in the case of Kapuni. Some also benefit from specific past benefits offered to incentivise exploration activity, such as what occurred in the mid-2000s following the Maui redetermination and decline in gas availability.

Royalty arrangements that apply to permits that account for the majority of current production see producers pay the higher of either 5% of revenue or 20% of profit.

The royalty forms part of the miner's operating costs and is payable in addition to company taxes on corporate profits. Royalties are however deductible for tax purposes.

Royalty and company taxes are together referred to in the industry as "Government Take" and typically comprises 42% of gross pre-royalty operating profit. Development of the Crown Minerals estate therefore represents a partnership under which the financial proceeds of production are shared between the Government and the operator.

Following the announcement, the E&P industry asked the Government to abandon the 2018 Blocks Offer process so that the ban could be discussed under normal Parliamentary process. That the Government responded to this request by truncating the consultation and Select Committee processes and stating that the urgency it had directed for was done for the benefit of industry to provide it with certainty ahead of the 2018 Blocks Offer was viewed by many in the sector as deeply cynical as a rationale for rushing legislation that the Government required to 'make legal' the announcement.

What little policy advice the Government did receive from its key advisors and agencies on the decision, particularly MBIE and The Treasury, was very negative. The main criticism of the announcement, which was positioned as a response to climate change, was the absence of any evidential basis to support the Government's assertion that intervening to restrict the upstream sector in NZ would deliver a downstream reduction in global or even local emissions. No formal cost/benefit analysis was undertaken however in their advice to Cabinet, MBIE and The Treasury concluded that the economic costs of the policy would be substantial and that global emissions would likely increase.

When the draft CMA Amendment Bill was tabled in Parliament its scope extended beyond the original announcement by including non-Taranaki onshore acreage as land that no further exploration acreage would be granted on. The result was that only onshore Taranaki Basin acreage was to be made available in future block offers. While this extension does not impact investors involved with offshore acreage, the signal it sent to industry and investors was again alarming.

The truncated Select Committee hearing process was no more than symbolic in the way it heard submissions from stakeholders and the draft Crown Minerals (Petroleum) Amendment Bill was returned to the House materially unchanged. On 7 November 2018 the bill was passed into law.

## Full CMA review

On announcing the ban, the Government attempted to provide existing E&P sector participants with comfort over the status of their investments. Central to this was a commitment that "*all existing permits will be honoured*". The Government has not since however provided any explicit detail or guidance as to how the statement should be interpreted or how it will be honoured.

In August the Government issued terms of reference (ToR) to initiate a "full review" of the CMA and a draft "New Zealand Resources Strategy". The two documents together serve as a position statement of the Government's intended direction of travel and signal what appears a likely fundamental recast of the CMA. The ToR signals an intention to replace the CMA's current emphasis on economic development with as-yet undefined principles of sustainability, fairness and wellbeing. Public submissions were invited on the draft Resources Strategy, with 546 responses received.

In November, a final post-consultation version of the Resources Strategy was released which was materially unchanged from the draft version. This was followed by the release of a discussion paper seeking public feedback, submissions on which close in January. The Government has said that final findings of the CMA review will be considered by Cabinet in early 2020 towards passing necessary legislation before the 2020 election.

## Investor reaction

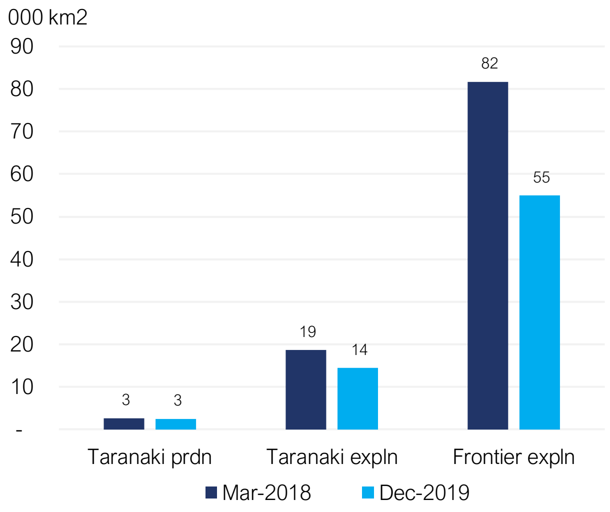
The events of the past 18 months have been deeply damaging to E&P investor confidence, both domestically and internationally. While it is clearly investors in and around the NZ energy sector which have been the most impacted, the ban has also regularly been cited by commentators as a contributor to low generalised levels of business and investor confidence.

NZ has historically scored very favourably on international investor screening and benchmarking indices for above-ground risk assessments on factors including political and policy stability, deregulation, transparency, ease of doing business, economic freedom and corruption. For large investors, such as energy multinationals, which allocate investment capital across often dozens of countries, judgements of these and other top-down indicators of country risk to support investment decisions are very significant.

With its post-announcement messaging the Government insisted that the decision did not have any immediate implications or consequences for investors with existing interests and instead is of only long-term dimensions. The reality however is that when making decisions over extremely long-lived investment horizons (it is entirely feasible for example that a frontier basin discovery made within the next couple of years could still be producing in the year 2100) E&P investors must constantly make judgements of long-term investment risk based on the information that is in front of them.

For existing and potential investors in NZ, the 12 April 2018 announcement cut completely across established assessments of regime stability and low country risk. That the Government also said at the time that it intended to review the entire regime that applies to all acreage within the current Parliamentary term without any indication as to the terms of reference for any review added substantial further forward uncertainty. A number of investors which had previously 'screened-in' NZ to their investment subset moved quickly to review their assessments with the result that NZ has since become 'screened-out'.

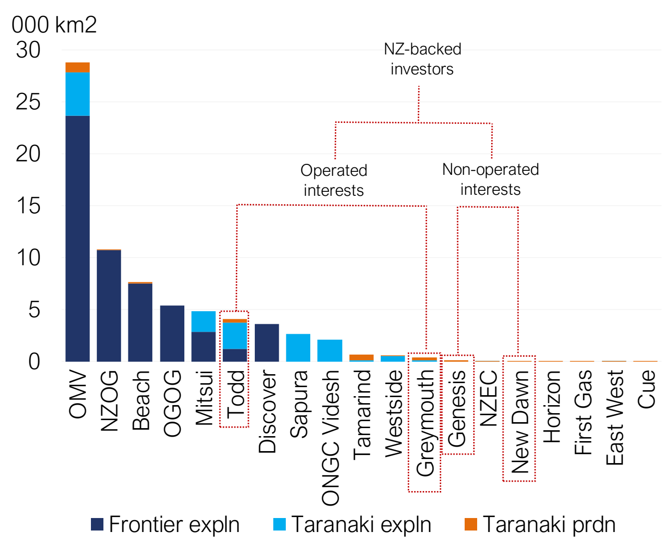
### NZ E&P acreage on issue pre- and post-ban




Source: Enerlytica

International capital has underpinned the E&P sector across most of its 50-year producing history. Before the ban was announced there were 25 companies with investment interests in NZ E&P acreage. Of these, only two were asset operators owned by NZ interests. Since the ban was announced five companies have exited their NZ positions, all of which are based outside of NZ. On-issue acreage has fallen by 30%, principally due to the exits of major multinationals Chevron and Equinor from their frontier basin interests. While each of Chevron and Equinor cited standard 'global portfolio management'-like themes in their public statements informing of their exits, 'the ban' is known to have played a significant role in each of their decisions.

### Net acreage positions by investor domicile




Source: Enerlytica

## 2019-20 MODU DRILLING PROGRAMME

For incumbents, the ban has served to refocus attention on their intentions for acreage that was on issue before the announcement.

OMV and its JV co-investors have commenced a major exploration drilling campaign targeting the Taranaki and Great South basins. The programme will comprise a minimum of four exploration wells in four separate permits. Of these, two of the permits have a drilling history that comprises only two wells while one of the permits has no drilling history. The fourth well will be drilled inside the Maui mining permit which already has an extensive drilling history with more than 35 exploration, appraisal and development wells having been drilled.

The COSL Prospector is a semi-submersible mobile offshore drilling unit (MODU) designed to operate in water depths of between 100 metres and 1,500 metres and drilling depths of up to 7,500 metres.

The rig was designed and built in Norway and commissioned in 2014. It is specifically designed for harsh environments. As a semi-submersible, the Prospector uses water as ballast and has six dynamic positioning system (DPS) thrusters that maintain its position while it is in operation. It also has the option of an 8-line mooring system.

The Prospector mobilises under its own power, meaning it does not require a tow to relocate. Before arriving into NZ waters in June 2019 the Prospector was working in the North Sea. At its cruising speed of 4 knots and with stops in Port Elizabeth and Perth the mobilisation journey to NZ took four months.

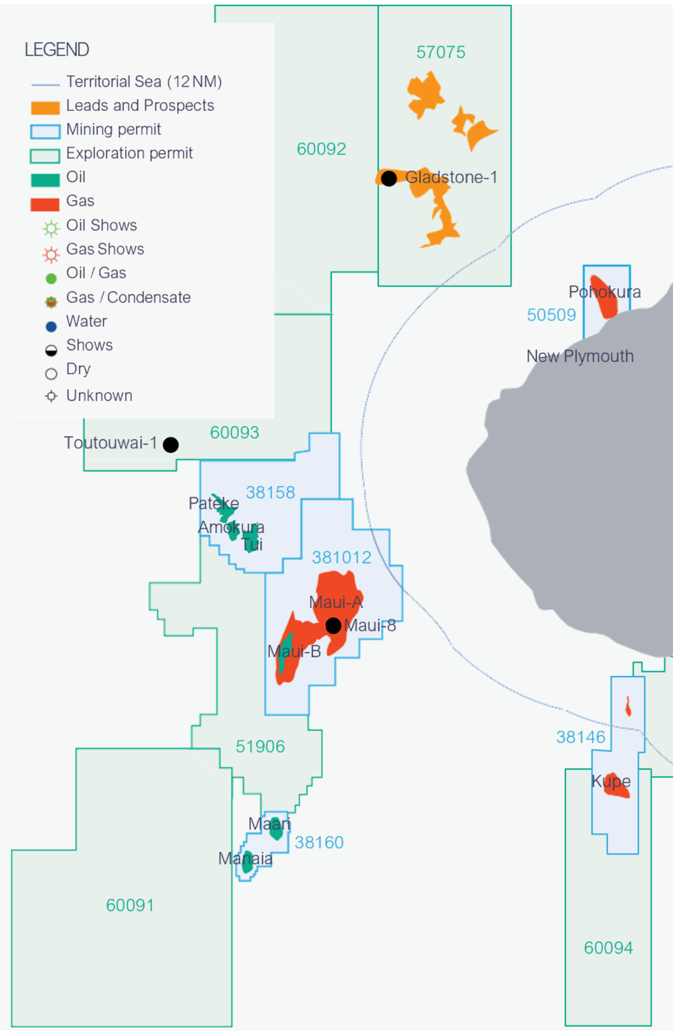
**Planned OMV-led 2019-20 COSL Prospector campaign**

| # | Well | Basin | Permit # | Permit name | Area km2 | Operator | Co-venturers | Likely spud | Permit drilling history |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gladstone-1 | Taranaki | PEP 57075 | Cloudy Bay | 1,365 | OMV 70.0% | Sapura 30.0% | Dec-19 | Arawa-1 (1991), Kanuka-1 (2007) |
| 2 | Tawhaki-1 | GSB | PEP 50119 | GSB | 16,715 | OMV 82.9% | MEPAU 17.1% | Jan-20 | Nil |
| 3 | Toutouwai-1 | Taranaki | PEP 60093 | Toutouwai | 2,135 | OMV 40.0% | MEPAU 30.0%, Sapura 30.0% | Mar-20 | Takapou-1 (2004), Kopuwai-1 (2007) |
| 4 | Maui-8 | Taranaki | PML 381012 | Maui | 785 | OMV 100.0% | | Apr-20 | ~40 |

Source: Enerlytica

Each of the wells will be drilled by the COSL Prospector semi-submersible MODU. OMV will commence its charter of the MODU at the beginning of December and will extend until mid-2020. If any of the wells prove successful it is likely that the JVs would commit to further appraisal drilling to build-out their knowledge of the extent of the discovery and to inform future decisions as to whether a commercial development of the discovery may be viable.

**Gladstone-1, Toutouwai-1 & Maui-8 exploration wells**




Source: Enerlytica

The Taranaki Basin component of the campaign will comprise, in order of sequence, the Gladstone-1, Toutouwai-1 and Maui-8 exploration wells. Each well will be drilled from individual wellsite locations that will require the MODU to mobilise and relocate between them. In between Gladstone-1 and Toutouwai-1 the MODU will relocate to drill Tawhaki-1 in the GSB.

## Gladstone-1 exploration well

The Gladstone-1 well will test the Gladstone prospect in permit PEP 57075, known as the Cloudy Bay permit. It will be the third well to be drilled in the permit after Arawa-1 (1991) and Kanuka-1 (2007). Another well, Taimana-1 (1983), was drilled in an adjacent permit but within 1km of the Western boundary of PEP 57075. All wells, including the proposed site for Gladstone-1, sit in ~130m of water. While Arawa-1 revealed gas shows in shallow Miocene sands, none of the three wells were drilled to a depth to test the deeper Miocene sands which is the primary reservoir objective for Gladstone-1.

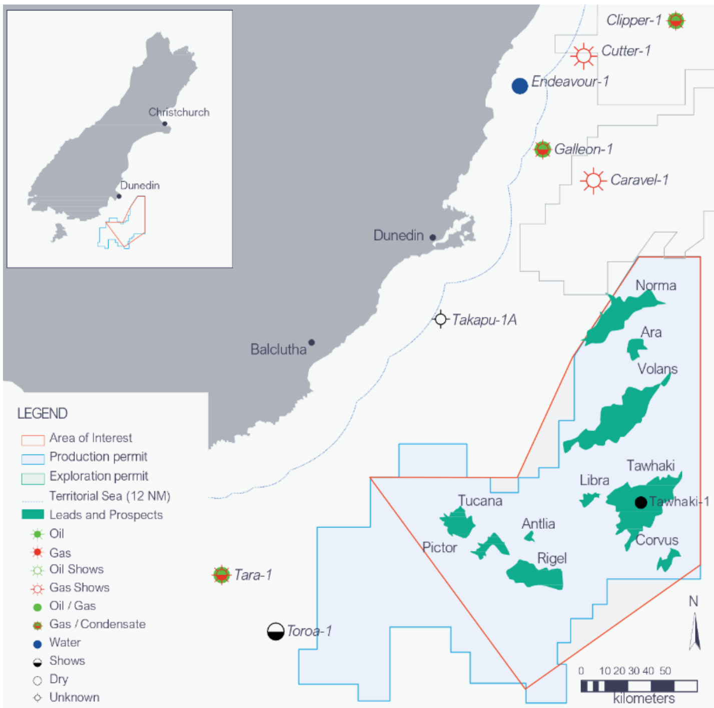
## Toutouwai-1 exploration well

Toutouwai-1 will be drilled in PEP 60093 and target a prospect directly to the North and on-trend with the Tui and Maui fields. The well will be the third to be drilled in the permit after Takapou-1 (2004) and Kopuwai-1 (2007). Neither well was a success with Takapou-1 registering only shows and Kopuwai-1 revealed as oil-bearing in poor reservoir quality rock. As is the case with Gladstone-1, Toutouwai-1 will be drilled in ~130m of water.

## Maui-8 exploration well

Maui-8 is planned to be the last of the four slated exploration wells in the programme. Located broadly equidistant between the Maui-A and Maui-B platforms, Maui-8 will be drilled ~40km off the Taranaki coastline in 110m of water. Its close proximity to the Maui field means that a discovery could be tied-in to Maui's existing infrastructure in relatively short time.

**Tawhaki-1 exploration well**




Source: Enerlytica

## Tawhaki-1 exploration well

After completing Gladstone-1 the MODU will relocate to drill Tawhaki-1 in the GSB. The main reason for allotting Tawhaki-1 as the second drilling slot in the programme is one of timing. Completion of Gladstone-1 to schedule will see the MODU become available during January. Opting to mobilise to the GSB at that time will ensure that maximum advantage can be taken of the summer weather window and with that more favourable sea-state conditions. This is not to offset any concern over safety (the Prospector is rated to handle sea conditions well beyond that which the GSB might produce) but is instead to minimise the risk of weather-related down-time which would impact not only Tawhaki-1 but also any other subsequent wells in the programme. This could include appraisal wells that OMV could commit to in the event of exploration success with any of its four scheduled wells.

OMV has concluded the Tawhaki prospect as the largest and most promising of at least 15 discrete leads within the permit.

## 2020 Maui-A crestal drilling programme

In addition to the MODU drilling programme, OMV has also committed to a multi-well sidetrack drilling programme to be undertaken from the Maui-A platform. The programme will use the Archer Emerald modular rig which will be installed on Maui-A to undertake a programme of six firm wells with an option for a further well. The duration of the firm component of the programme is slated for 13 months with the contingent component expected to run 2-3 additional months.
The rig is being mobilised from Norway and expected to arrive at Maui-A to commence drilling in March.

The Emerald is the same rig that undertook a very similar programme from Maui-A between 2012 and 2014 which targeted bypassed gas and resulted in a significant increase to Maui reserves which extended Maui’s economic life. That programme was stated by Archer at the time to be valued at US$45m however cost and time overruns incurred likely resulted in the ultimate cost significantly exceeding plan. The cost of the 2020 programme is likely to exceed NZ$200m.

As was the case in 2012-14, the objective of the programme is to upgrade current 2C contingent resource to reserves status. The 2012-14 campaign succeeded in delivering a significant net increase to Maui 2P reserves, totalling +350 PJ. Returns from the 2020-21 programme are not expected to be as strong however due to a lower 2C resource base and expected lower recovery rates as the field continues to mature.


Archer Emerald rig atop the Maui-A platform

# 2. EXPLORATION SUCCESS

## WHAT IS 'EXPLORATION'?

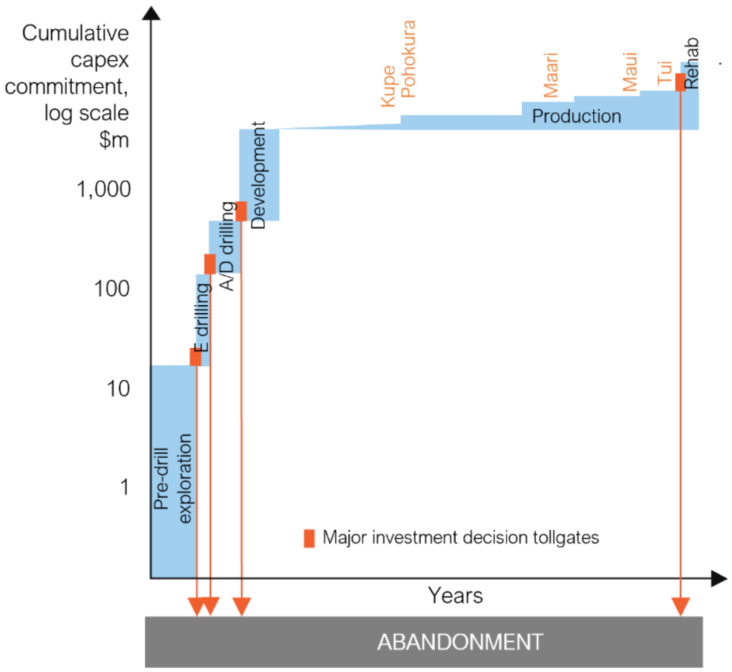
"Exploration" is a generic term that covers an explorer's work programme over the period before a commercial discovery is made, or not in the case of a failed result. This period can span many years and involve, depending on decisions and commitments made along the way, tens and sometimes hundreds of millions of dollars of capital investment.

Major go/stop decisions are made at different stages along the investment continuum. These decision points, often referred in the industry as 'tollgates', require increasing levels of corporate resource and commitment to proceed beyond. Between tollgates technical evidence is built to enable informed subsequent investment decisions to be made.

## WHAT IS 'SUCCESS'?

Industry outsiders often mistakenly interpret the term 'exploration success' as being one of binary dimensions. While it is true that a 'dry' well (meaning no trace of oil and/or gas is found) does indeed represent a clear nil result, it is common (particularly in established producing regions) for wells to encounter hydrocarbons (often referred to as 'pay') during the drilling stage, often in formations where hydrocarbons were not expected to be present

**Indicative E&P life cycle vs capital commitment**




Source: Enerlytica

### Exploration & corporate strategy

E&P is fundamentally a business of strategy, risk and portfolio management. Company positioning over the types and locations of assets to focus on to achieve its growth ambitions are guided by the company's strategy and portfolio. Execution decisions that fall from the strategy tend to fit into one of three generic categories:

1. Organic – E&P investment in exploration, appraisal and/or development asset activities in the company's own name towards identifying and commercialising new resources. In NZ, such past examples of OMV-led investments include:
   - Exploration: Acquiring the outer-Taranaki basin exploration permits in 2015 blocks offer and subsequently investing in exploration-led work programmes to de-risk the acreage to a stage where it will now be drilled.
   - Appraisal/development: In 2014-15 leading the $500m Maari Growth Project to drill four new development wells towards an objective of doubling production from Maari.

2. Acquisition – Acquiring established E&P assets from their owners. Investment decisions can involve assets that are either or both of asset and corporate in nature. In NZ, such past examples of OMV-led investments include:
   - 1999: Acquired Cultus Petroleum and with that a 30% interest in the Maari field.
   - 2002: Acquired a further 49% interest in Maari from Shell NZ.
   - 2018: Acquired the upstream asset portfolio of Shell NZ including operated interests in the producing Pohokura and Maui fields and onshore terminal and handling facilities.

3. Disposal – Exit of assets that are deemed surplus to the company's strategy. In NZ, past examples of OMV-led divestments include:
   - 2002: Sold a 10% Pohokura stake to Todd.
   - 2003: Sold a 10% Maari stake to Horizon Oil.
   - 2016: Sold its 10% interest in the Maui pipeline to First Gas.
   - 2019: Sold (subject to conditions) its 69% operated interested in the Maari field to Jadestone Energy.

It is similarly common for wells to encounter pay in multiple formations while en route to a well's ultimate target depth, often referred to as 'stacked pay', which can provide developers with optionality over which formation or formations to commercialise, or not.

If a discovery is made, initial flow and pressure test readings mean that it often becomes quickly apparent when the discovery is material. Just as common however are readings that are not immediately conclusive and which require further analysis and testing to determine the extent of the discovery. In NZ there have been numerous examples of non-commercial discoveries, with one recent example being the Ruru discovery made near the Maui permit in 2014. An earlier case is Kupe which despite being first discovered in 1986 was deemed non-commercial for more than 20 years until 2006 when the new JV agreed that the field was commercially viable to develop. Kupe now contributes an important cornerstone of supply into the North Island gas market.

There are also multiple examples where what were considered as high-probability appraisal and/or development wells have been drilled but have been determined as non-commercial, with the recent Tui-3H well drilled by Tamarind probably being the highest profile such Taranaki Basin example.

Further South, three of the 14 wells drilled in the GSB-C have been assessed as "non-commercial discoveries". Of these the most positive have been the Clipper-1 (1984) and Galleon-1 (1985) wells which each registered material but not commercial gas-condensate discoveries.

## Below-ground risk

In the early stages of an exploration work programme, the risk of a non-commercial outcome is extremely high. Depending on the extent of commitment an explorer has already made to the programme – in particular, whether a commitment has been made to fund the drilling of a well – the cost of failure can also be very high.

### Singular probabilities and costs

The programme wells will carry differing levels of pre-drill estimated geological ($P_g$) and commercial ($P_c$) success. The lowest-probability wells are likely Tawhaki-1 and Gladstone-1 with a $P_c$ estimate of approximately one-in-five. The highest-probability wells are likely Maui-8 and Toutouwai-1 with a $P_c$ of approximately one-in-three.

Drilling costs will depend on an array of input factors and costs including drilling contact time, MODU mobilisation and demobilisation, drilling support and service costs. As most service providers including MODU operators charge on a daily rate basis, time overruns can be extremely costly.

### What does "discovery" actually mean?

When exploring for oil and gas the investor's objective is to make a commercial discovery which can be developed and a return on investment made.

Whether the result of a well can be regarded as a discovery does not usually reflect the Eureka!-like moment that many believe. Instead, there are typically two lenses that are applied to measure the extent of success of any well:

1. Technical discovery describes a drilling outcome where a hydrocarbon accumulation has been encountered and the oil and/or gas is moveable, broadly meaning that the hypothesis of the exploration team has been validated.

2. Commercial discovery describes where the discovery is assessed to have characteristics and be of a scale to justify the commercial development of the resource.

Under these definitions it is therefore possible (and in fact very common) for an exploration well to be concluded as a non-commercial discovery, meaning that the well succeeded as a technical discovery but post-completion testing concluded its characteristics (including but not limited to scale) as not being sufficiently positive to justify development.

To support portfolio screening and capital allocation processes, exploration teams typically deduce a probability-based approach to assessing individual prospects. That approach usually calculates a probability of success (PoS) by compounding individual probabiltiy assessments for the noted five geologic markers of success: (1) Source; rock; (2) Reservoir rock; (3) Migration; (4) Trap and; (5) Seal. From these assessments, two distinct measures of success are defined:

1. Probability of geological success ($P_g$) describes the likelihood of a technical discovery as deduced by compounding a series of geologic success/fail probability assessments.

2. Probability of commercial success ($P_c$) describes the likelihood of identifying a techical discovery that exceeds the pre-drill assessment of the minimum economic field size (MEFS) required to support the commercial development of the discovery.

**Programme well $P_g$, $P_c$ and cost range estimates**

| Well | 3D? | Likely Pg range | Likely Pc range | Likely cost range |
|---|---|---|---|---|
| Gladstone-1 | Yes | 30-40% | 15-25% | US$20-30m |
| Tawhaki-1 | Yes | 20-30% | 15-25% | US$50-70m |
| Toutouwai-1 | Yes | 40-50% | 25-35% | US$20-30m |
| Maui-8 | Yes | 40-50% | 25-35% | US$20-30m |

Note: Cost indication is on dry-hole basis excluding MODU mobilisation and shared costs

Source: Enerlytica

Direct well cost estimates also tend to exclude shared programme costs such as rig mobilisation and demobilisation to and from NZ. Due to the transit times involved these costs are substantial and, depending on the length of the programme, can serve to double direct drilling costs.

At its extreme therefore, Tawhaki-1 presents a greater than 75% likelihood of a non-commercial outcome and a full write-off of its NZ$100m drilling cost. Including indirect programme and MODU mob and demob costs could increase this to as much as NZ$150-200m.

### Compound probabilities and costs

While on a standalone basis the $P_g$ and $P_c$ estimates are each singularly low, as a programme of four wells the rule of compound probabilities means that the likelihood of at least one well being successful is much higher. At an assumed average $P_g$ of 40% across the four-well programme, the probability of at least one well being declared a technical success increases to 87%. On a $P_c$ basis, assuming a average programme $P_c$ of 25%, the probability of at least one well being declared a commercial success increases to 68%.

## Scale, Materiality

Resource scale is the most significant constituent of geological and commercial success. It is also one of the major components of explorer capital screening and decision making. If an opportunity is assessed as not sufficiently material to the explorer's business or portfolio to justify the risk and resource commitment involved then the explorer will be unlikely to undertake further work on it. For OMV, which reported group production of 427 kboe/day and reserves of 1.3 bln boe for its most recent financial year, the opportunity in NZ will need to be significant in scale.

Analysis by GNS in 2015 estimated it as likely that, on a 2P basis, six undiscovered oil fields of between 100 mmbbl and 1 bln bbl reside in the GSB-C region and two fields within the same range remain in the Taranaki Basin. GNS also estimated seven undiscovered gas fields of between 300 bcf and 3 tcf in the GSB-C and four within the same range in the Taranaki Basin.

**Estimates for undiscovered oil & gas fields**

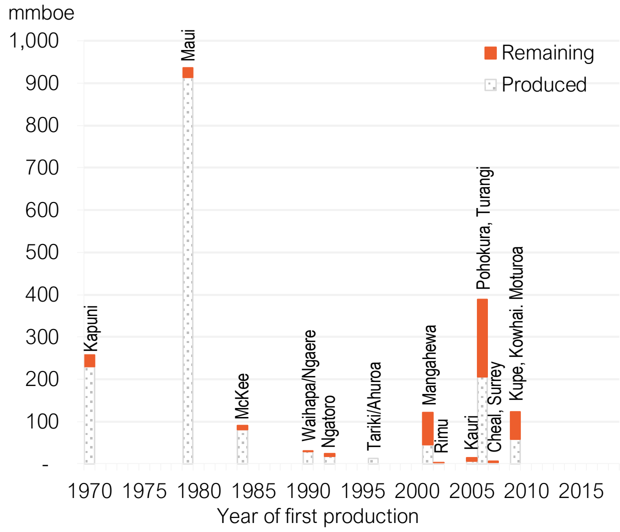
| P50 basis | | Taranaki Basin | GSB | Canterbury Basin |
|---|---|---|---|---|
| Oil | | | | |
| 301 - 1,000 mmbbl | # | - | 1 | 1 |
| 101 - 300 mmbbl | # | 2 | 2 | 2 |
| 31 - 100 mmbbl | # | 4 | - | 1 |
| Gas | | | | |
| 3.1 - 10 tcf | # | - | - | - |
| 1.1 - 3 tcf | # | 1 | 1 | 1 |
| 0.3 - 1 tcf | # | 3 | 3 | 2 |

Source: GNS estimates, Enerlytica

If OMV and its co-investors were to strike success by discovering a field consistent in scale with GNS's estimates then materiality would not be an issue. This is particularly the case in the GSB-C where an oil-rich discovery at the top-end of GNS's scale estimate (ie within a range of 500 mmbbl to 1 bln bbl) would be of scale comparable in scale to the Maui field and therefore of global significance. The same would be true of a gas-rich discovery where at the top-end of the scale a 5-10 tcf discovery would also be of global relevance in scale.

In the Taranaki Basin, where a discovery is likely to be smaller, the likely ≤300 mmbbl scale for an oil-rich discovery would nonetheless still be very material to investors. A gas-rich discovery of ≤3 tcf would also be very significant as broadly twice the size of Pohokura.

**Taranaki 2P gas-rich fields by year of first production**




Source: MBIE data, Enerlytica

# 3. COMMERCIALISATION

## De-risking towards FID

Exploration success by way of a positive drilling outcome represents by far the largest de-risking step in the commercialisation process. An exploration well that delivers on its pre-drill prognosis serves to almost immediately eliminate $P_g$ and $P_c$. It also potentially opens an array of future options for the developer. Ahead of that however there is an extended process of information gathering and due diligence required of the operator and its co-investors to build out their understanding of the geologic characteristics of the discovery to enable a FDP to be devised.

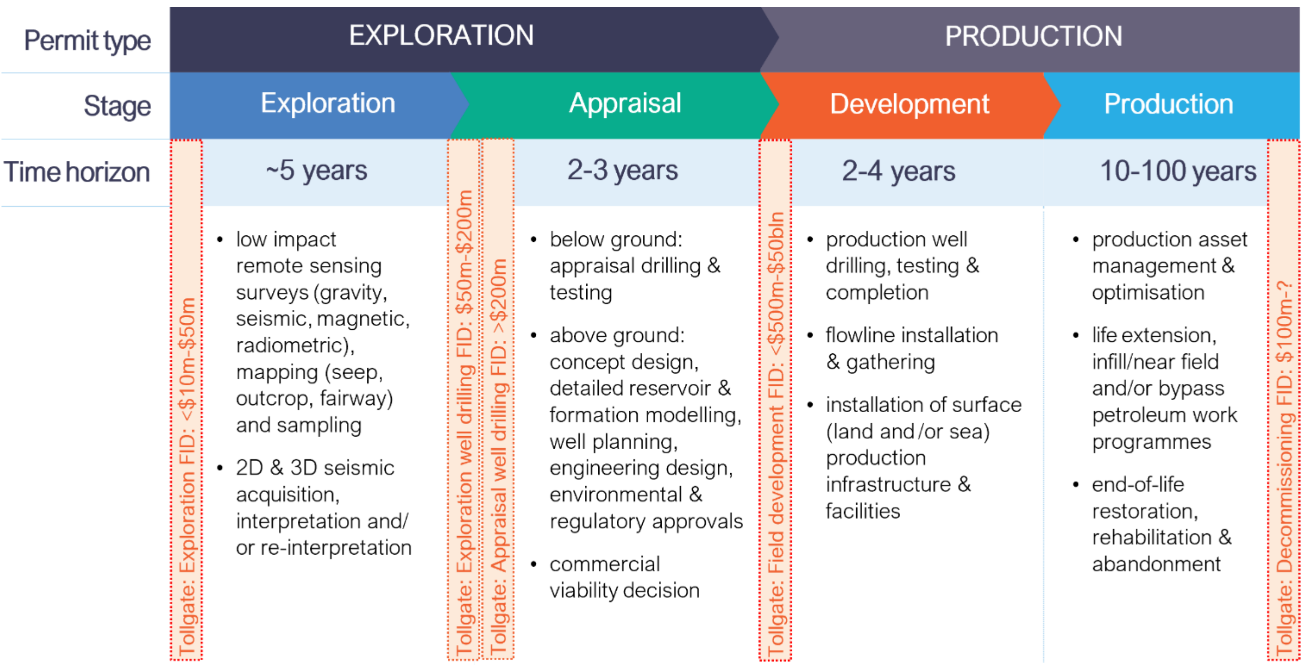
A successful exploration well does not however represent the overcoming of all below-ground risk. There are multiple cases of material oil and/or gas discoveries where investors have decided not to proceed further with subsequent development work. One such example is the offshore Karewa gas discovery made in 2003 in the Northern Taranaki Basin. Despite the field having been assessed to hold 165 PJ of 2C contingent resource, operator Todd Energy has to date opted not to proceed with development due to the relatively small scale of the discovery and low oil component to the well stream, making for comparatively weak economics.

### Appraisal

In the event of exploration success from any of the four programme wells, OMV as operator would engage with its JV co-venturers to recommend and seek funding approval for an appraisal drilling programme. Initially this would involve completing the exploration well to take core samples and complete testing to assist towards determining the quality of the reservoir. It may also be deemed appropriate to drill a short deviation to the main wellbore to test surrounding areas. The cost of this well completion process is additional to the direct (dry hole) costs of the well itself and can vary significantly depending on the type of activity and testing undertaken. For each of Gladstone-1, Tawhaki-1 and Toutouwai-1 completion costs are likely to range between US$10 and US$30m.

For Maui-8, completion costs are likely to be substantially lower due to the extensive existing geologic information held in the permit and as a result a reduced need for primary datapoints.

**E&P work programmes and key decision tollgates**




Source: Enerlytica

In each case, particularly in respect of Gladstone-1, Tawhaki-1 and Toutouwai-1, further drilling would be undertaken to build out an understanding of the discovered reservoir and to allow detailed mapping of the deposit to be completed. There would likely be a gap following completion of the drilling of the successful exploration well of 1-2 years while analysis is completed, views reached as to where the appraisal wells should be drilled and a MODU contracted and mobilised to undertake the additional drilling.

Appraisal wells are usually drilled with the intention of them being completed as production wells if and when the discovery is ultimately developed.

## COMMERCIALISATION PATHWAYS

Decisions around how to bring a discovered oil and/or gas resource to market involve integrating a myriad of highly complex and interrelated technical, commercial and market considerations. While it is the case that in some situations relatively uniform development decisions can be taken that can rely on a 'cookie-cutter' approach to above- and below-ground development infrastructure and route-to-market (US shale gas is probably the clearest such example), this is not the case for conventional E&P projects, including those being advanced by OMV and its partners in NZ.

### Field development plan

The FDP formalises a comprehensive plan to develop the discovery that involves detailed engineering and design and accounts for every aspect of the discovery's subsurface characteristics, its geographical location, the technology available to the project's sponsors and the above-ground commercial context.

To reach a point where a final FDP is approved by the project's sponsors involves a period of engagement between and across internal and external stakeholders that is all of intensive, extensive and expensive.

The initial design concept for the above-ground handling and production infrastructure will be framed to the high-level characteristics of the discovery. Among the most significant of these are:

- Reservoir charge and composition – the extent of saturation and liquids/gas split in the reservoir
- Reservoir extent – the breadth and depth of the reservoir rock that makes up the accumulation
- Water cut – whether an aquifer is also present with the accumulation and, as a result, whether water will also need to be produced and managed with the well stream.

**FDP workstreams, processes and stakeholders**

| | TECHNICAL | COMMERCIAL | REGULATORY |
|---|---|---|---|
| WORK STREAM | **Below-Ground**<br>• well design<br>• reservoir mapping<br>**Above-Ground**<br>• surface production infrastructure | • EPC agreements<br>• production support agreements<br>• product-to-market arrangements<br>• financial risk management<br>• insurance<br>• JV relations & engagement | • production permitting<br>• environmental consenting<br>• community engagement |
| INTERNAL STAKEHOLDERS | • geophysics<br>• petroleum engineering<br>• reservoir engineering | • business development<br>• legal<br>• regulatory<br>• compliance | • regulatory management<br>• stakeholder relations<br>• community affairs |
| EXTERNAL STAKEHOLDERS | • structural engineering<br>• subject matter experts<br>• geotechnical advisors<br>• EPC contractors | • legal advisors<br>• financing advisors<br>• insurers<br>• auditors<br>• JV partners | • local government<br>• central government<br>• regulatory agencies<br>• environmental advisors |

FUNDER & JV APPROVALS

FID

Source: Enerlytica

**Likely default FDPs**

| | **Greenfield** Offshore handling & processing | | **Tie-in** Onshore handling & processing | |
|---|---|---|---|---|
| | FDP default | Analogues | FDP default | Analogues |
| Liquids-rich |  | • NZ: Tui, Maari, Maui-B*<br>• International: >300 in operation worldwide |  | • NZ: Maui, Pohokura, Kupe<br>• International: 100s |
| Gas-condensate |  | • NZ: none<br>• International: ~5 operating, many pending & planned | | |

Note: FPSO Whakaaropai was on station at Maui-B between 1996 and 2006

Source: Enerlytica

## 1. Liquids-rich

OMV's central success scenario for each of the four programme wells is for a liquids-rich resource. This would not mean a liquids-exclusive resource as there would likely be a cut of associated gas of 10-20% (on an energy-equivalent basis) that would accompany liquids production. Produced gas would either be used onsite towards running production operations or piped to market onshore.

A liquids-rich discovery would likely see a FPSO form the basis of the processing module of the FDP. FPSO is the preferred modern-day solution for remote liquids-rich resources for reasons including:

- portability – FPSOs can be rapidly mobilised and demobilised to respond to changes short- and long-term operating circumstances including end-of-life depletion, major weather events and political events.
- scalability – FPSOs are often converted oil tankers, providing significant scale flexibility and capital cost control during the conversion process.
- capital intensity – locating all producing infrastructure on a single site in very close proximity to the field serves to avoid the requirement to build onshore production facilities and undersea pipelines, significantly improving field economics and helping to improve the viability of marginal fields that would otherwise be uneconomic.
- own/operate outsource – it is common for FPSOs to be owned and operated by specialist third-party operators, reducing developer capital commitments.

The exact configuration of the supporting above-ground infrastructure that would accompany a FPSO-based FDP would rely on a large number of technical and commercial decisions. One of the most important early decisions is whether to provide for a permanent wellhead platform (WHP) as part of the FDP.

Including a WHP adds significantly to the project's up-front capital cost but has the advantage of providing a single gathering point for all sub-surface equipment and provides better access to the wells over the life of the field. Opting not to provide for a WHP would generally require the installation of submerged flexible riser systems to gather flowlines for relay to the FPSO. Riser systems generally include mid-water arches to support flow lines and control systems as they rise from the seabed.


Tui FPSO Umuroa offloading to shuttle tanker

Maari FPSO Raroa and WHP

**FPSO comparisons**

| Field | First prdn year | Prdn wells # | 2P URR mmboe | Water depth m | FPSO handling capacities | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | Oil kbopd | Liquids kbopd | Gas TJ/day | Storage kbbl |
| Maari | 2009 | 9 | 44 | 102 | 40 | 50 | 37 | 660 |
| Tui | 2007 | 4 | 47 | 120 | 54 | 120 | 27 | 775 |
| Egina | 2019 | 44 | 550 | 1,600 | 208 | 502 | 244 | 2,300 |

Source: Enerlytica

There are examples of each format already operating in NZ:

- **Maari** is a 44 mmbbl oil field that lies 80km off the South Taranaki coast and has been in operation since 2009. The field has a permanent WHP which gathers crude from the field's nine production wells and relays it via three subsea flowlines to the FPSO Raroa anchored 1.5km away. Maari operator OMV has led an extensive well intervention campaign over the past few years which has involved regular use of the WHP.
- **Tui** is a 47 mmbbl oil field that lies 50km off the West Taranaki coast and has been in operation since 2007. Oil is produced from five wells tapping three separate reservoirs and the well stream relayed to the FPSO Umuroa via a flexible riser system. A notable aspect of Tui is high oil-water contact which, with the field now deeply mature, makes for a very high water cut and commensurately very low oil cut.

In both cases, FPSOs offload produced crude to shuttle tankers via a remote offtake buoy system.

Important to note is that while each of the Maari and Tui fields are large by NZ standards, they are relatively small by global standards. The largest FPSO in operation, which entered production in early 2019 and was custom-built by French multinational Total to produce from the deepwater Egina oil field off the coast of Nigeria, has a handling capacity of 200,000 bopd and storage capacity of 2.3 mmbbl.

A liquids-rich development of any of the Gladstone, Toutouwai or Tawhaki prospects would likely deploy a FPSO-based FDP. Whether or not that FDP would include a WHP would not be decided until a discovery had been fully assessed and a view taken as to the level of operational flexibility that would be required. Based on peer projects and estimates for undiscovered resource, for Gladstone and Toutouwai the gross recoverable resource that OMV and its partners would be targeting would likely range between 75 and 100 mmbbl plus a gas cut of 10 to 20%. For Maui-8, the target is likely considerably smaller at between 15 and 30 mmbbl, plus gas cut. For Tawhaki the assessed success case is likely an order of magnitude larger, probably to the extent of >500 mmbbl, plus gas cut.

If there was a significant gas component to a discovery at Gladstone or Toutouwai a gas connection could be laid to connect to the Pohokura WHP and then relayed to shore to be handled through the Pohokura production station. A discovery at Maui-8 would likely be tied-in to the Maui-A platform with new production comingled with existing Maui production and relayed to Maui's onshore production station at Oaonui. Each could therefore become important future new components to the North Island gas market and therefore support security of domestic energy supply.

At Tawhaki, excess produced gas (ie less what the FPSO uses to power its own systems) would likely be reinjected to the reservoir.

## 2. GAS-RICH

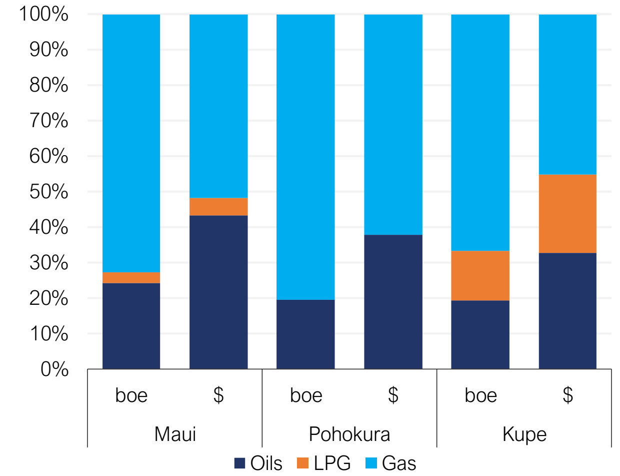
A gas-rich development would involve a material discovery that presents a high gas cut. Whereas under a liquids-rich scenario the gas stream is secondary in both physical and financial significance to the liquids stream, a gas-rich scenario sees the focus of the FDP placed on monetising the gas stream.

While a liquids-rich resource is OMV's central scenario, the history of Taranaki Basin and GSB E&P infers a firm possibility of a gas-rich discovery. Each of the Maui, Pohokura and Kupe fields are gas-condensate fields with gas cuts of 70-80% on a energy basis. Notably however, the higher energy unit value of oil compared to gas means that the financial (as proxied by revenue) contribution of oil to field economics is close to double that of its energy contribution.

The question of how a gas-rich discovery could or would potentially be commercialised has no single or formulaic answer. Selection of a FDP would rely on a number of below- and above-ground influences beyond the generic factors (being reservoir charge and composition, reservoir extent and water cut) already noted. They include:

- Downstream sink – large-scale, long-term gas sale arrangements with one or more downstream gas buyers would need to be put in place to underwrite a development.
- Connectivity – whether there may be optionality to tie-in to existing offshore and/or onshore processing infrastructure which could reduce capital intensity and increase productivity.

**Energy & revenue makeups of NZ offshore relay fields**



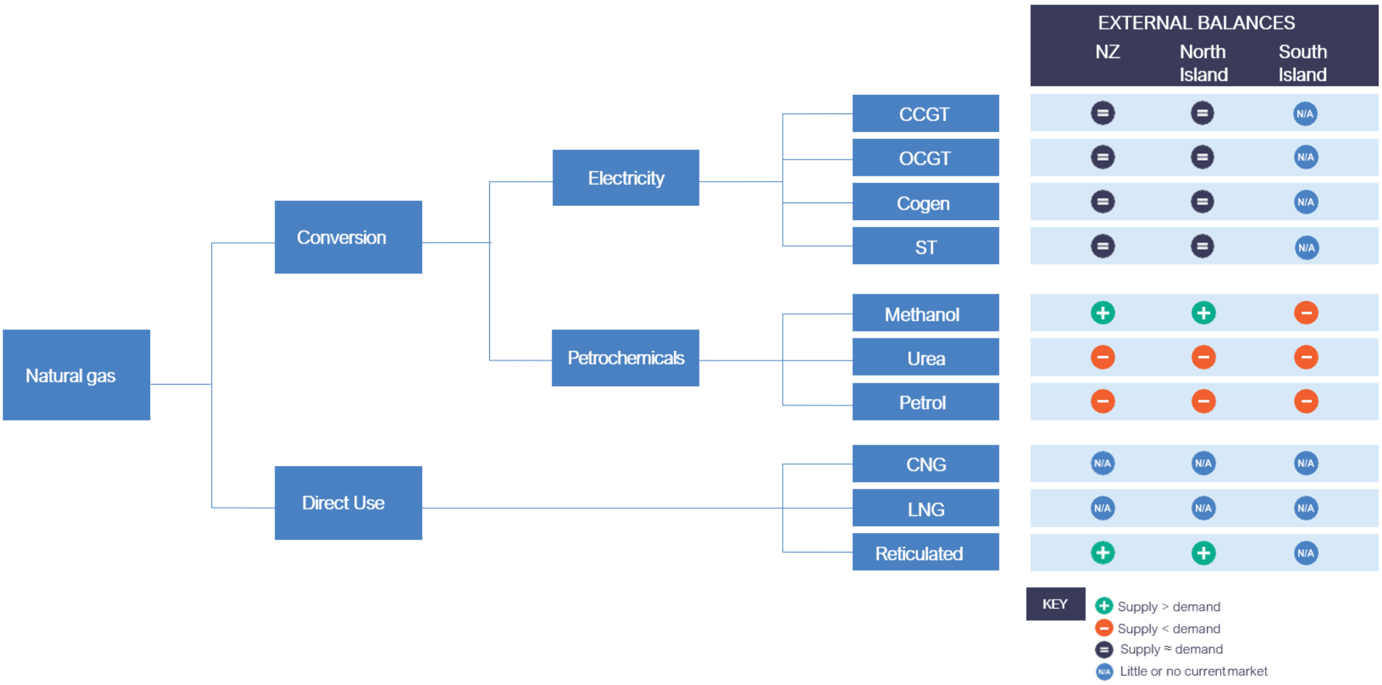

Note: oil assumed at US$60/bbl, LPG at US$450/t, gas at $6.00/GJ, USD at 0.65

Source: Enerlytica

- Condensate-gas ratio (CGR) – the higher per-unit value of liquids compared to gas makes the CGR important towards supporting field economics (the higher the CGR the stronger the economics).

Of these factors it is the securing of a downstream sink for produced gas that will initially serve as the most important determinant of a preferred FDP. The production scale of a significant discovery would require the commitment of one or more large downstream customers. In the NZ market context, the ultimate destination for the backbone of new gas production would be the international marketplace, whether directly (as export LNG) or indirectly (as gas reformed into petrochemical products, such as methanol and urea).

**Gas value chain**




Source: Enerlytica

Across the four scheduled programme wells there are two generic FDP outcomes that could be feasible in the event of a gas-rich discovery:

1. Tie-in – Connecting the field's new production wells with the existing infrastructure of established producing fields. Of the four programme wells by far the most likely tie-in candidate is Maui-8 which could be readily connected to the Maui-A WHP from where production could be relayed to shore via the existing Maui-A to Oaonui pipeline. A gas-rich discovery at either of Gladstone and/or Toutouwai could also potentially be tied-in to the Pohokura WHP from where production could also be relayed onshore to the Pohokura production station. In all tie-in cases, significant work would likely be required to the onshore production stations to be able to accommodate the new production, however the cost of this work be substantially less than would be the case with a greenfield build. A feature of a tie-in development would be that new gas production would add significant additional supply-side depth to the North Island gas market.

2. Greenfield – The most likely form of a greenfield development in the event of a gas-rich discovery would be as FLNG. This would involve the construction at a specialist shipyard of a large purpose-built vessel to house all production infrastructure. While LNG is very mature as a means of producing and transporting gas with a commercial history that dates back more than 100 years, FLNG is relatively new as a FDP concept. LNG production and storage is equipment-intensive and requires a large physical footprint which until recently has ruled out floating concepts. The scale of a greenfield build would depend on the size of the discovery and the characteristics of the resource. Currently there are five FLNG facilities in operation around the world ranging in size from 500 ktpa (28 PJ pa) to 3.6 mtpa (200 PJ pa). The largest produces from the Prelude field in Australia.

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 its gaseous form and is not combustible while refrigerated making it ideal for ship or land-based transport to market. At its point of destination, LNG is offloaded and stored in cryogenic tanks. When required the LNG is reheated to restore it to its gaseous form after which it can be injected into the local market gas distribution network. LNG can therefore be regarded simply as a virtual gas pipeline connecting a point of gas production to points of gas consumption. Major LNG producer/exporters include Australia, Qatar, Malaysia and Indonesia. Major LNG importers include Japan, South Korea and the UK.

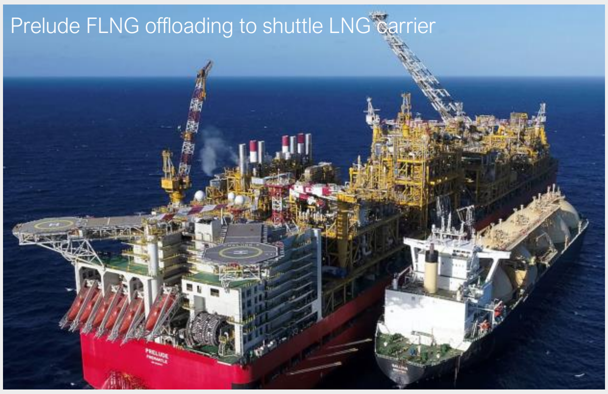
Prelude FLNG is a remote production facility located entirely at sea 200km off the Australian Northwest coast. The facility, which is operated by Shell on behalf of a JV that includes co-venturers Inpex, KOGAS and OPIC, comprises a 488m long vessel moored permanently in 248m of water. It is the largest vessel ever put to sea anywhere in the world.

First production was achieved in December 2018 and following ramp-up its first LNG export cargo was shipped in June 2019. Sales product is offloaded to shuttle LNG, oil and LPG carriers which moor alongside the FLNG vessel to load their cargoes.

The vessel handles production from the Prelude and Concerto gas-condensate fields which are together estimated to house between 3,000 and 5,000 PJ of recoverable gas. On board the vessel is all extraction, treatment, separation, liquefaction and storage equipment and facilities to produce 5.3 mtpa of natural gas liquids comprising 3.6 mtpa of LNG, 1.3 mtpa condensate and 0.4 mtpa of LPG. This equates to annual capacity production of 200 PJ gas, 12 mmbbl condensate and 400 kt of LPG. Individually and collectively, these metrics make Prelude highly comparable in size to the Maui gas-condensate field.

The vessel is expected to be onsite for 25 years but has been built to handle 1-in-10,000 year weather events including tropical cyclones. One of the major advantages of the FLNG production concept is its mobility which will enable the vessel to be redeployed once the field has been depleted and protects against many of the risks that traditional land-based concepts faced including the risk of asset stranding in the event of unexpected reservoir performance or security issues such as an adverse change in a host nation's political stability.

Prelude FLNG offloading to shuttle LNG carrier

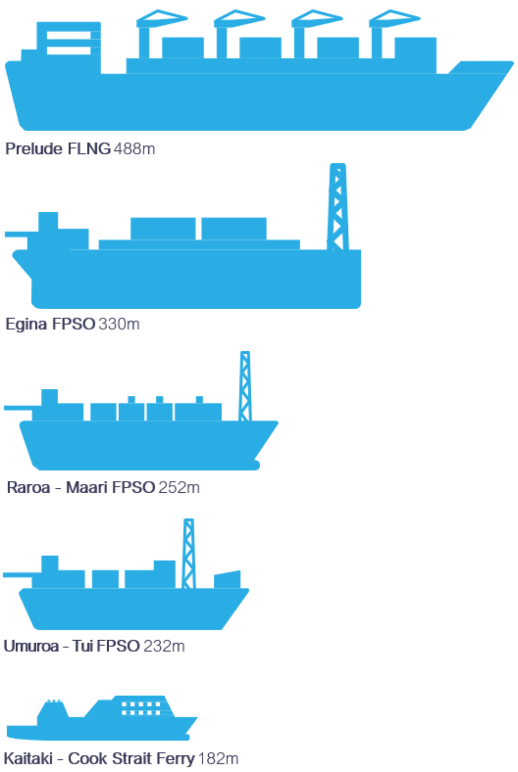


Although unlikely, there is no reason that a FDP to accommodate a gas-rich discovery at either Gladstone or Toutouwai could not be developed as FLNG. The same is also the case in respect of an unexpectedly large and gas-rich discovery at Maui-8, although a tie-in to Maui-A is by far the more likely scenario.

Of the programme wells it is Tawhaki where FLNG presents the strongest commercial fit. If a material discovery at Tawhaki was revealed as gas-rich its scale could prove comparable in size to Maui.

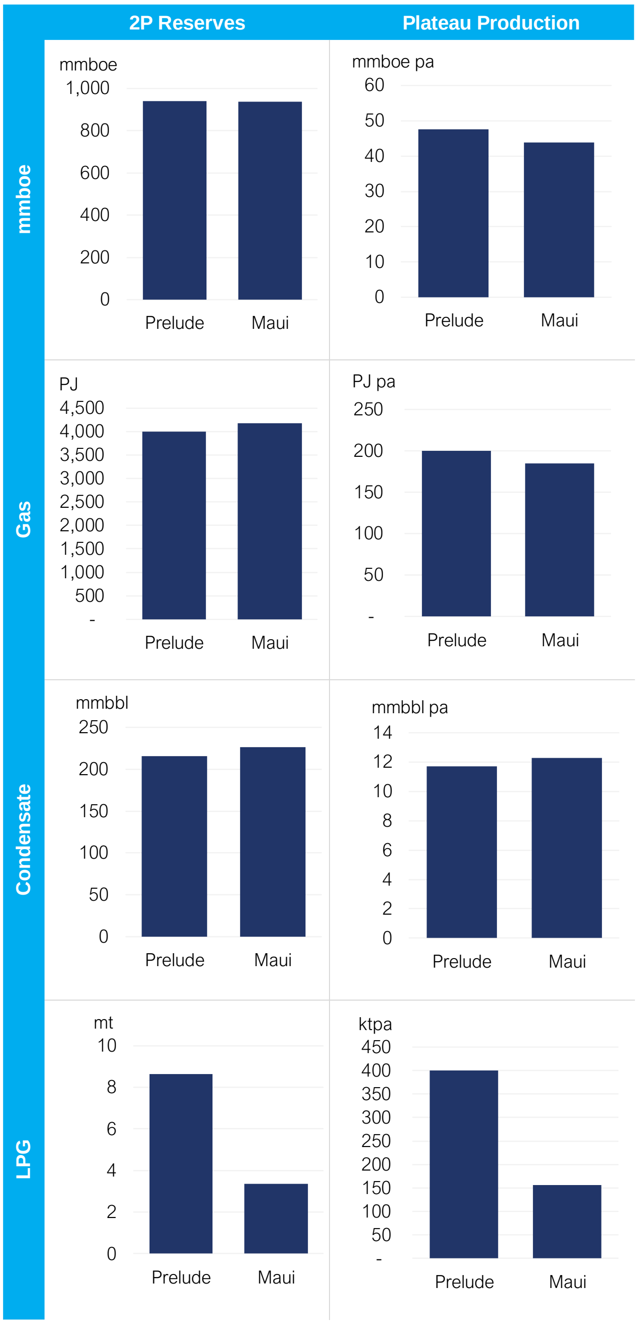
Prelude and Maui share many similarities. Each is a gas-condensate field with 2P ultimate recoverable gas reserves of ~4,000 PJ, total (including condensate and LPG) recoverable reserves of ~940 mmboe, plateau production of ~45 mmboe pa and a similar condensate/gas ratio. If a field analogous to Maui was discovered in the current day, even if that discovery was made in the Taranaki Basin with its existing onshore gas market infrastructure, it is likely that FLNG would be the default FDP to commercialise the discovery.

**Relative vessel scales**




Source: Enerlytica

**Prelude vs Maui scale comparators**




Source: Enerlytica

## Policy considerations

As part of the commercial considerations over a potential FDP, there would be a myriad of policy issues to navigate before a development could proceed. The implications of these issues are far-reaching and, depending on outcomes, could even prevent an exploration success-backed development from proceeding.

The dominant current policy theme is that of political and regulatory uncertainty. The first principles nature of the CMA review and the direction of other regulatory reforms and programmes currently being progressed by the Government add significant current uncertainty and therefore forward risk to investor decision making.

There are three broad areas where policy considerations present strong potential impact to a possible project development.

### 1. Crown Minerals Act

With the CMA review only in its formative stages, the level of uncertainty towards potential outcomes is currently extremely high. Government briefing and discussion papers issued to date indicate a major shift in emphasis for the CMA away from an overall objective of maximising economic recovery towards that of sustainability. This appears likely to include a recasting of the purpose statement of the CMA to demote or delete economic development in favour of adopting environmental objectives. This is despite the extractives sector already needing to comply with all environmental legislation and regulations that apply across the economy, including the recently enacted Climate Change Response (Zero Carbon) Amendment Act.

For OMV and its co-investors, and for the E&P sector in general, grandfathering is an aspect of particular concern and uncertainty. With its April 2018 announcement the Government sought to provide comfort to existing permit holders by stating that all rights and entitlements associated with existing permits would be honoured. To date however this statement has not been supported by any binding commitment from the Crown on which E&P operators can rely.

Notwithstanding this, the assurance provided is in any case of little significance to those explorers that continue to progress their existing exploration permit work programmes. While existing PEP regulations do provide for the Crown to grant the PEP holder an extension of up to four additional years to undertake appraisal activities in the event of exploration success, if the explorer wished to develop the discovery into continuous production they would need to apply to the Crown for a Petroleum Mining Permit (PMP). While existing regulations provide exclusivity to the PEP holder to apply for a PMP in the event of a discovery, the PMP application process itself is a greenfield one.

There are no automatic 'upgrade' rights that accompany a PEP and applicants must meet defined criteria for a PMP to be granted. The PMP process as it is currently defined in the CMA provides for the Crown to take into account in its consideration of the proposed FDP "*alternative FDPs, and whether the proposed plan is optimal in terms of the purpose of the Act, the maximum recovery of economic reserves, and good industry practice*". The process also provides for the Crown to account for "*any market or economic considerations that are relevant to determining maximum economic recovery*".

The main implications are:

- The Government's "all existing rights are intact" assurance is of no material significance to an existing explorer that has realised exploration success in an exploration permit and seeks to develop a discovery.
- The situation in existing production permits (for example Maui) where mining rights are already documented is much clearer which should provide much higher confidence with investment decisions in the event of exploration success.
- The CMA in its current form provides the Crown with absolute decision-making discretion over the final FDP, albeit within a lens of maximising resource recovery.
- Unless holders of existing PEPs are grandfathered into a new CMA regime, the review of the CMA means there is currently deep certainty over what arrangements would apply should OMV and its co-investors realise exploration success and seek to develop a discovery.

### 2. Climate change regulation

Other components of the Government's policy work programme also serve to significantly increase forward investor uncertainty while policy is under development.

A representative example is the recent announcement by the Minister for Climate Change that any major future decision to be considered by Cabinet will now require a mandatory "climate impacts assessment". Just how such an assessment will be constructed is not yet known but its application and interpretation could have a significant impact on both commercial and policy decision making. Probably the aspect of greatest uncertainty with the proposed assessment framework is whether it will take into account (as appears likely) only direct climate change impacts to NZ or whether it will take account of expected global climate change impacts. The difference may be nuanced but its interpretation is of critical policy making importance.

A current live example lies in Rio Tinto's lobbying of the Government for assistance to maintain its aluminium smelting operation at Tiwai Point. Through a NZ-specific lens the climate impact case for providing financial support would be negative given that Tiwai Point is one of NZ's largest-emitting sites. If a global climate impact lens was applied however the climate impact case for financial support would be positive as the exit of Tiwai Point from NZ would almost certainly mean an increase in global emissions as the capacity lost from NZ would likely be filled from increased production from marginal plant, probably in China, and probably using coal-fired electricity generation.

For E&P investors the approach that Government will take to formulating a climate impacts assessment will be an important consideration towards preparing and proposing a FDP. The same issue exists in the area of broader regulatory reform where climate change impacts could be incorporated into approval processes where the law does not currently provide for climate change to be considered. A clear such example is the EEZ Act which is the guiding legislation under which the Environmental Protection Authority would consider an application by a developer for marine consents to support the development of a new discovery.

Interpretation could for example guide a developer's thinking towards whether to incorporate CCS, at substantial additional cost, into its proposed FDP.

### 3. CCS

CCS (or CCUS) is itself a complicated energy policy issue where significant uncertainty exists. CCS is not prohibited in NZ however the regulatory framework does not explicitly accommodate it. The situation is therefore uncertain and the Government does not currently appear to regard CCS as a policy priority. This is despite all major multilateral energy agencies including the International Energy Agency and the World Energy Council having identified CCS as a critical enabler of deep decarbonisation. Locally, in its Low Emissions Economy investigation completed in mid-2018 the NZ Productivity Commission concluded CCS as a "*rapidly evolving and potentially significant mitigation technology, which could be well-suited to large-scale, single-source emitters such as iron, steel and aluminium production*". The Commission also recommended that MFE should undertake policy work on new legislation to regulate CCS activities under a bespoke CCS Act. No such work appears to have yet begun.

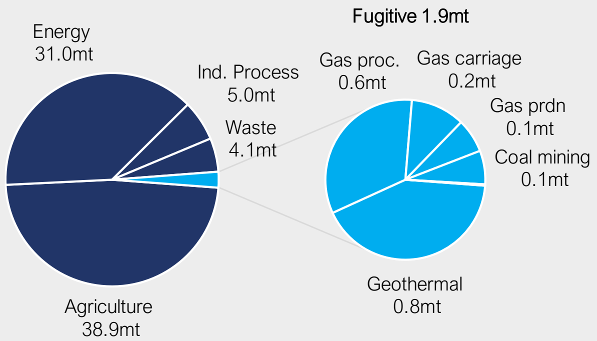
In practical terms, a small number of E&P companies already employ CCS in their operations although not with the explicit objective of permanently storing $CO_2$-e as a standalone activity. Kapuni is the clearest such example where high-$CO_2$ gas is reinjected to the field however this is in part done to support reservoir pressure and as such to support enhanced oil recovery. The Kapuni example is therefore more CCUS than CCS.

Carbon capture and storage (CCS) describes where $CO_2$ is recovered from an industrial process and then injected into deep geological formations for permanent storage, thereby preventing its release into the atmosphere. CCUS is a variant that incorporates Utilisation which describes where instead of being injected for permanent storage $CO_2$ is applied towards productive uses including for enhanced oil and/or gas recovery, agricultural products and the production of building materials.

A common misconception is that $CO_2$ associated with the consumption of petroleum products is attributable to production. In reality, much of the $CO_2$-e associated with oil and gas production is embedded in finished goods, with the result that the impost associated with the $CO_2$-e is incurred at the point of consumption. Petrol is probably the clearest such example, where it is motorists who pay for the ETS impost when they buy petrol, not the crude oil producer that supplies the raw material from which petrol is produced.

Consistent with this, oil and gas sector emissions are limited to fugitive emissions, being those that are directly attributable to the production process. Totalling 1 mtpa, the largest sources of fugitive $CO_2$-e emissions in NZ are gas flaring (where excess gas that cannot be used elsewhere in the production process is burned off at the production station) and $CO_2$ venting (where $CO_2$ separated from the well stream and which cannot be used elsewhere in the production process is released directly to the atmosphere). The majority of flared gas is likely to be from the Maari field (where there is no gas connection to shore and no economic means to recover and/or reinject produced gas) while most vented $CO_2$ is likely to originate from the Kapuni field (where the raw gas stream is 44% $CO_2$ with currently no economic option to sequester all $CO_2$ that is produced). Most other NZ gas-condensate fields are very low in emissions intensity due to having only small $CO_2$ components to their well streams (avoiding the need to vent) and being able to sell produced gas into the reticulated market (avoiding the need to flare).

NZ gross $CO_2$-e emissions



For a developer of a substantive new discovery CCS could, depending on the composition of the well stream, be a material consideration in preparing the FDP. In some cases, CCS may be unavoidable as part of the FDP to enable commercialisation. An example of this is the manufacture of LNG from a $CO_2$-rich discovery. The LNG liquefaction process requires that nearly all $CO_2$ be removed from the input gas stream, which forms part of the FDP. $CO_2$ can then itself be compressed and reinjected back underground for either permanent storage or to support enhanced oil recovery. The world-scale Gorgon LNG project undertakes precisely this process which sees it recover up to 4 mtpa of $CO_2$ pa that would otherwise be vented to the atmosphere and reinject it into a formation 2km beneath the LNG plant for permanent storage.

# 4. RETURNS ON INVESTMENT

The potential returns on the investments that OMV and its co-venturers have committed to can be considered through two distinct lenses:

1. Investment returns – estimated risked and unrisked returns attributable to project stakeholders including providers of risk capital and the Crown; and
2. Macroeconomic benefits – national benefits that success from the programme would likely deliver, including towards supporting domestic energy security of supply, affordability and sustainability.

## 1. INVESTMENT RETURNS

### RISK CAPITAL AND RETURNS

Oil and gas E&P is very capital intensive and can be very high risk. With its Tawhaki-1 well OMV and its co-investor Mitsui face a 75% likelihood of a full write-off of their joint investment of NZ$90m. With the average $P_c$ likely to be similar across the other three wells in the programme, the implication is that OMV faces a nearly one-in-three chance of no commercial return on its total programme investment of NZ$200m. E&P investors are however by definition 'calculated optimists' who back themselves to beat the odds.

#### Success economics

Quantifying what development success could look like is a fundamental aspect of investment decision making for any E&P investor. For larger E&P companies with bigger capital budgets there is a larger pool of opportunities to allocate capital towards. Screening the potential investment returns of individual opportunities against all others in the company's opportunity pool is a cornerstone aspect of E&P portfolio management. The standard approach taken by investors to evaluating the relative quality of individual investment opportunities is discounted cash flow (DCF) analysis.

### UNRISKED RETURNS

Cash flow forecasts are cast on the assumption of exploration success and a subsequent development of the discovery. The mapped cash flows therefore do not reflect the initial $P_c$ risk of the exploration well itself. The forecasts do however give an indication for what the commercial profile and returns of the project could present as if developed.

Discounted cash flow (DCF) analysis is a valuation methodology that integrates estimates for key bottom-up value drivers to enable expected future cash flows to be forecast, from which an estimate for the time value of money can be applied to calculate a present value for the investment opportunity being considered.

DCF analysis requires objective assessments of key below-ground and above-ground value drivers to enable estimates to be made for individual revenue and cost items. This requires the input of a large number of subject matter experts and teams including petroleum engineering, reservoir engineering, structural engineering, legal, accounting and commercial.

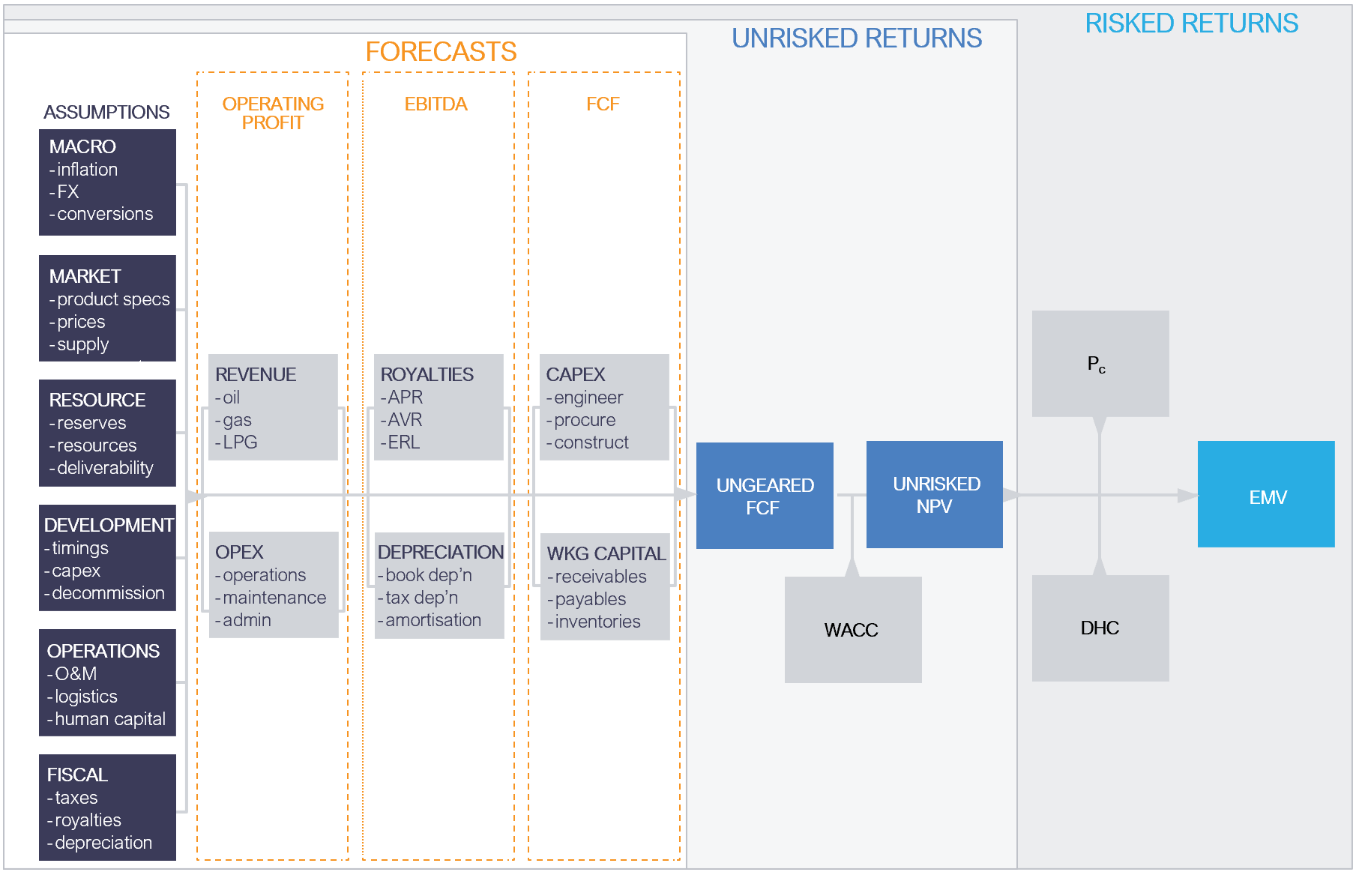
Project cash flows are modelled typically on a nominal (inflation-inclusive) basis across the expected economic life of the project, which can extend to many decades. Cash flows are discounted back to the present day to reflect the opportunity cost of capital.

For E&P projects, investment returns are typically considered on an equity investor basis, thereby ignoring any benefits (due to the lower post-tax cost of debt) of debt financing (referred to as gearing or leverage).

Cash flow forecasts are based entirely on the underlying assumption set of individual scenarios. Investors typically undertake extensive sensitivity analysis to test for the responsiveness of project economics to changes in different variables.

A sponsor's weighted average cost of capital (WACC) is also a critical component of valuation. While the calculation of WACC usually involves a process of estimating and aggregating individual components of equity and debt financing towards striking a sponsor-specific average cost, E&P investors tend to apply a uniform cost of capital estimate to screen projects. That cost of capital tends to ignore leverage and instead reflect only the tax-adjusted cost of equity, in other words to set the weighting of debt in WACC calculation to zero. A typical benchmark that many E&P companies apply to their screening processes is 10% on a nominal post-tax basis. In valuation exercises this is often abbreviated to NPV10.

**E&P prospect valuation methodology**




Source: Enerlytica

## Risked Returns

E&P investors account for exploration risk within project economics by applying $P_c$ to unrisked project returns to derive a risk-adjusted expected monetary value (EMV). From this the irrecoverable sunk failure case cost of drilling the prospect, referred to as the "dry hole cost" (DHC), is then deducted from the EMV. It is this EMV aggregate and variations of it (for example, EMV per boe, EMV per US$ of DHC) that E&P companies typically look to benchmark when screening exploration prospects. The calculation is simply:

$$EMV = \text{Unrisked NPV} \times P_c - (1 - P_c) \times DHC$$

While due to not meeting auditor certainty tests EMV valuations of exploration assets are not typically ascribed to company asset registers, EMVs do tend to be factored in forward-looking economic valuations, such as those of the share market.

## Crown Returns

All royalties and taxes paid by asset operators from their mining of the Crown mineral estate are made directly to the Crown's general fund. This means that all royalties and taxes payable on mining activities are used directly to fund core government services including health, education, welfare, housing, law and order, Working for Families contributions, Government Superannuation Fund contributions and operating the public service.

While profits made by E&P operators during the operating life of the development are fully taxable, profit-based royalties received by the Crown are not subject to tax. While this is logical in the context of the Crown's tax-collecting role (taxing the royalty stream as revenue would be a zero-sum exercise for the Crown), in the hands of any other owner the value of the royalty stream would be higher than it is in the hands of the Crown to reflect its net-of-tax value. All else equal, the royalty stream would be valued by a standalone owner at a level 38.9% (being the gross-up of the NZ corporate income tax rate of 28.0%) higher than it would be by the Crown.

### Cost of Crown capital

The Crown has a cost of capital that is substantially lower than non-government entities due to factors that include a lower overall risk profile, the ability to levy taxpayers for income and its non-taxpaying status.

These factors are consistent with the Crown's involvement in the revenue stream that it receives as royalties and corporate tax from oil and gas production. The nature of those arrangements present low initial risk to the Crown given it does not contribute any capital towards developing the income-generating asset, but by law receives a share of the revenue that is generated by that asset. In this respect the Crown enjoys a free carry on earning its interest in the asset.

Treasury and MBIE have previously agreed that a discount rate of 3.0% on a real terms pre-tax basis (equivalent to 5.1% on a nominal pre-tax basis assuming an inflation rate of 2.0%) should be applied in situations where the Crown is required to consider alternative FDPs under the CMA. This rate was specified in the Minerals Programme for Petroleum 2013 (section 8.3) and was applied by MBIE (supported by The Treasury) in the Regulatory Impact Statement analysis that accompanied the August 2018 Cabinet Paper on 'the ban'.

### Crown risked and unrisked returns

Just as risked and unrisked economics can be calculated for companies that are investing as direct equity participants to an exploration programme, the same can also be estimated for the returns that the Crown could receive in the event of a successful commercial development.

There are two fundamental methodological differences to account for when compiling risked and unrisked economics of the Crown versus the same for a commercial operator. They are:

1. Cash flow profile – For the Crown, royalty and tax arrangements are skewed heavily in favour of success. This is due to the Crown's limited downside exposure to a failure outcome (which is generally restricted to tax losses claimed by investors on an unsuccessful exploration well) but full exposure to a success outcome (via the ~42% 'Government Take' of gross profits realised from production).
2. WACC – The Crown's nominated WACC is approximately half that of a commercial operator, the result of which is a substantially higher valuation of future success case cash flows.

The compound of these two factors mean that the risked and unrisked economics for the Crown are each extremely strong.

The table below summarises the risked and unrisked economics from each of the four potential developments through the lens of both the investor JV and the Crown. The pages that follow present summary return profiles of oil-rich development scenarios of each prospect being targeted by the four exploration wells in the programme. The charts following these show the estimated cash flow profile that success at Tawhaki could generate and compare unrisked and risked stakeholder returns for each prospect.

### Key points relating to investment returns:

- The fiscal terms that define participation in the NZ E&P sector mean that in the event of exploration success the Crown on behalf of the people of NZ receive a substantial and long-term revenue stream. Unlike is the case for equity investors, this return is received without needing to contribute up-front development capital. Because of this, across all four prospects, exploration success would prove far more lucrative for the Crown than it would for equity investors.
- A success-backed development at Tawhaki would by a considerable distance be the most lucrative scenario for stakeholders, but particularly the Crown. In present value terms, the $12 bln of royalties and taxes the Crown would realise from a development of Tawhaki approximates the level of annual Government funding required to operate the entire NZ education sector.
- Investment returns account only for direct financial flows that a success-backed development would likely deliver. In addition to this, exploration success could yield significant economic benefits including export receipts, increased GST and PAYE tax bases, a stronger currency and support for regional development.

**Summary JV & Crown stakeholder returns**

| | | | | EMVs | | JV investment returns | | | Government Take | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Cond. mmbbl | Gas PJ | Total mmboe | JV $NZm | Crown $NZm | NPV10 NZ$m | RTEP | VIR | Royalties | Corp. tax | Total |
| Gladstone-1 | 80 | 105 | 97 | 72 | 376 | 405 | 13.6% | 0.25 | 862 | 703 | 1,565 |
| Tawhaki-1 | 550 | 725 | 665 | 954 | 2,875 | 4,098 | 16.1% | 0.54 | 6,244 | 5,401 | 11,645 |
| Toutouwai-1 | 80 | 63 | 90 | 198 | 544 | 687 | 20.6% | 0.47 | 905 | 771 | 1,676 |
| Maui-8 | 19 | 12 | 21 | 24 | 162 | 150 | 17.7% | 0.27 | 268 | 243 | 512 |
| **Total** | **729** | **906** | 872 | 1,248 | 3,958 | 5,340 | | | 8,280 | 7,118 | 15,398 |

Source: Enerlytica

# Gladstone

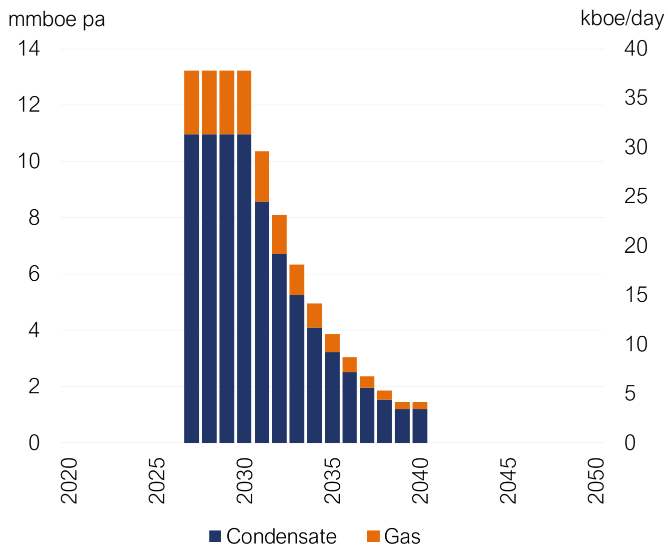
## KEY ASSUMPTIONS

| | | |
|---|---|---|
| Commissioning year | Year | 2027 |
| | | |
| Produced - condensate | mmbbl | 80 |
| Produced - gas | PJ | 105 |
| Produced - condensate+gas | mmboe | 97 |
| | | |
| Plateau - condensate | kbbl/day | 30 |
| Plateau - gas | TJ/day | 40 |
| Plateau - condensate+gas | kboe/day | 36 |
| | | |
| Long-term Brent | US$/bbl | 65.0 |
| Pc | % | 25% |
| Long-term USD/NZD | $ | 0.640 |
| | | |
| DHC | US$m | 25 |
| Development capex | US$m | 1,740 |
| Development capex | US$/boe | 18.0 |
| Opex | US$/boe | 13.0 |

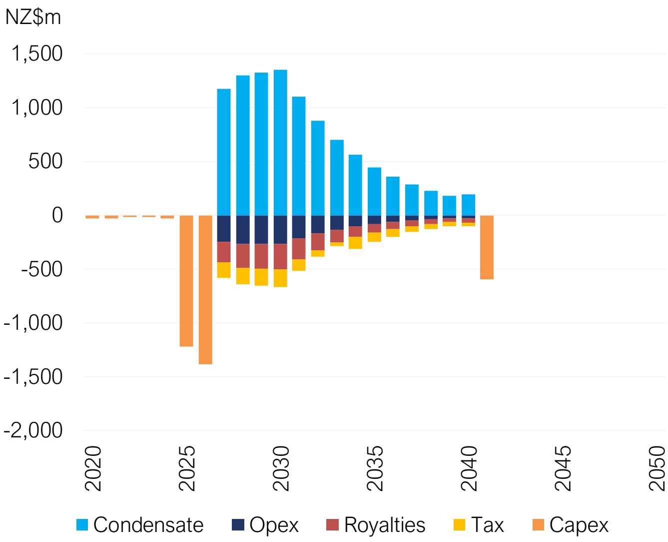
## INVESTMENT RETURNS

| | | | |
|---|---|---|---|
| **Unrisked project returns** | | | |
| NPV10 | NZ$m | 405 | |
| NPV10 | US$m | 259 | |
| IRR nominal | % | 15.9% | |
| RTEP | % | 13.6% | |
| VIR | x | 0.25 | |
| DPP | Years | 12 | |
| | | | |
| **Government take** | | | |
| Royalties PV | NZ$m | 862 | |
| Tax PV | NZ$m | 703 | |
| Total PV | NZ$m | 1,565 | |
| | | | |
| **Risked EMVs** | | JV | Crown |
| Success case EMV | NZ$m | 101 | 391 |
| Failure case EMV | NZ$m | -29 | -15 |
| EMV | NZ$m | 72 | 376 |

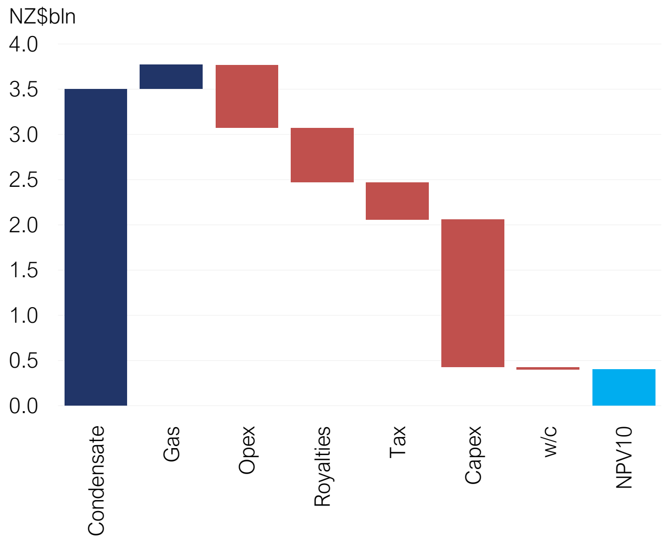
## PRODUCTION



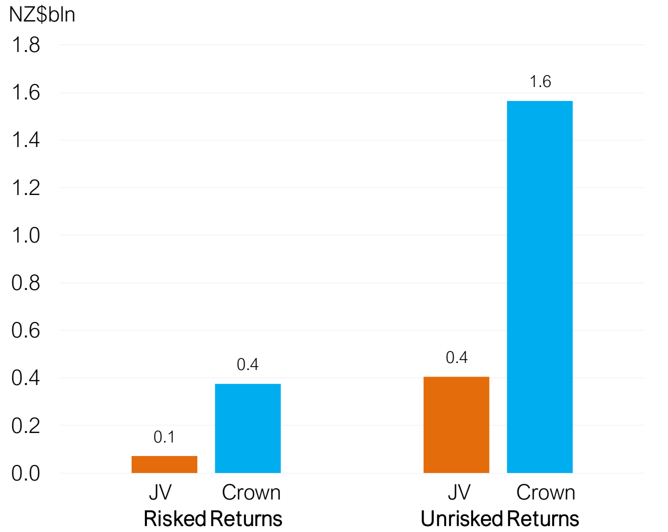

## CASH FLOW PROFILE




## SHAREHOLDER NPV10 CONSTITUENTS




## STAKEHOLDER RETURNS




Source: Enerlytica

# Tawhaki

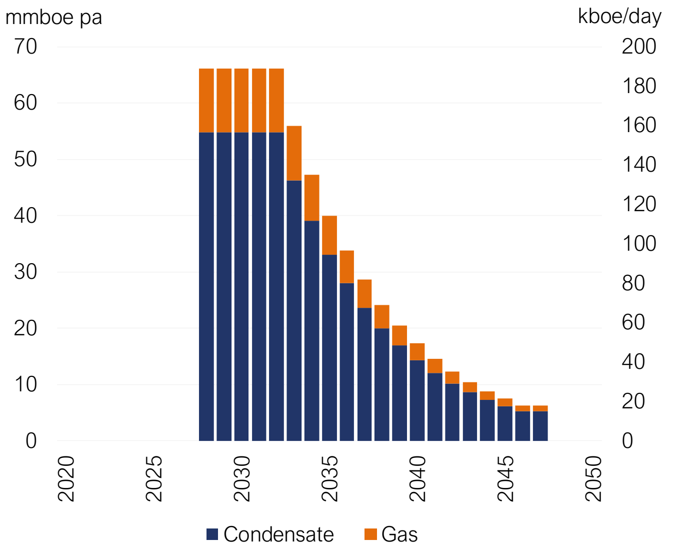
## KEY ASSUMPTIONS

| | | |
|---|---|---|
| Commissioning year | Year | 2028 |
| | | |
| Produced - condensate | mmbbl | 550 |
| Produced - gas | PJ | 725 |
| Produced - condensate+gas | mmboe | 665 |
| | | |
| Plateau - condensate | kbbl/day | 150 |
| Plateau - gas | TJ/day | 198 |
| Plateau - condensate+gas | kboe/day | 181 |
| | | |
| Long-term Brent | US$/bbl | 65.0 |
| Pc | % | 25% |
| Long-term USD/NZD | $ | 0.640 |
| | | |
| DHC | US$m | 60 |
| Development capex | US$m | 8,640 |
| Development capex | US$/boe | 13.0 |
| Opex | US$/boe | 6.5 |

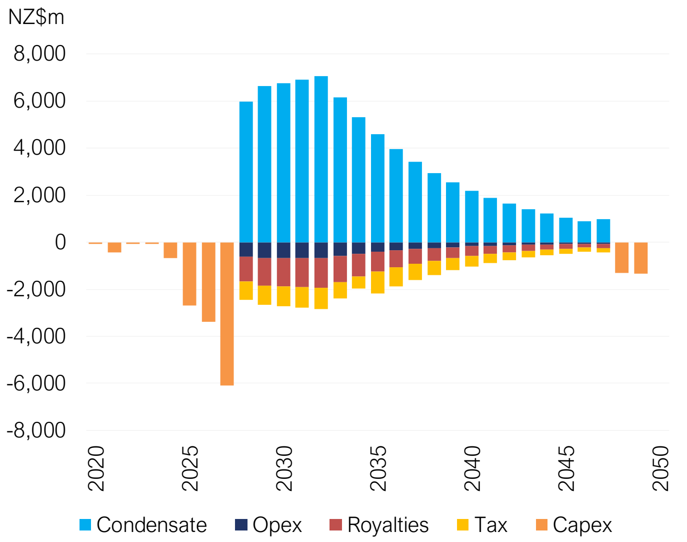
## INVESTMENT RETURNS

| | | | |
|---|---|---|---|
| **Unrisked project returns** | | | |
| NPV10 | NZ$m | 4,098 | |
| NPV10 | US$m | 2,623 | |
| IRR nominal | % | 18.4% | |
| RTEP | % | 16.1% | |
| VIR | x | 0.54 | |
| DPP | Years | 13 | |
| | | | |
| **Government take** | | | |
| Royalties PV | NZ$m | 6,244 | |
| Tax PV | NZ$m | 5,401 | |
| Total PV | NZ$m | 11,645 | |
| | | | |
| **Risked EMVs** | | JV | Crown |
| Success case EMV | NZ$m | 1,024 | 2,911 |
| Failure case EMV | NZ$m | -70 | -36 |
| EMV | NZ$m | 954 | 2,875 |

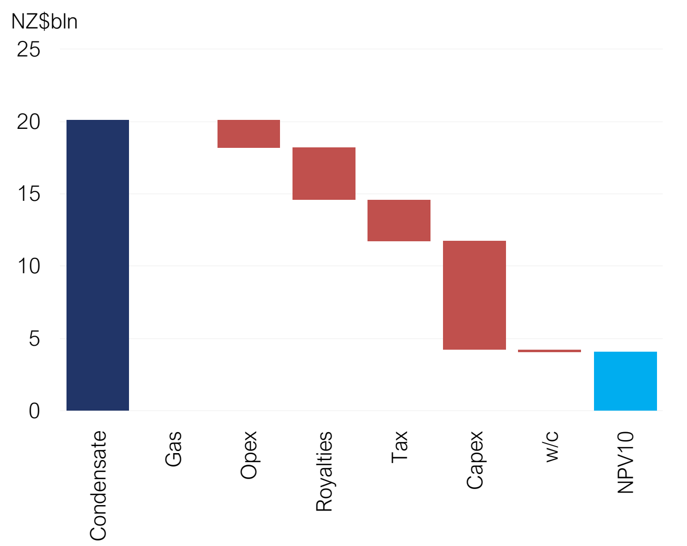
## PRODUCTION



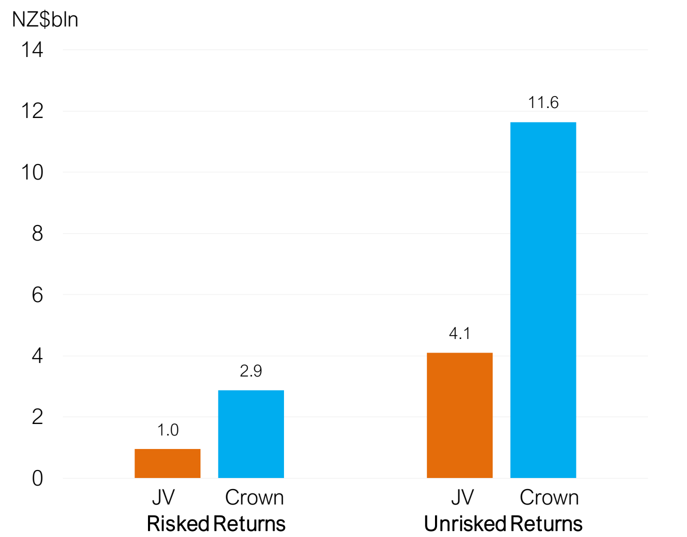

## CASH FLOW PROFILE




## SHAREHOLDER NPV10 CONSTITUENTS




## STAKEHOLDER RETURNS




Source: Enerlytica

# Toutouwai

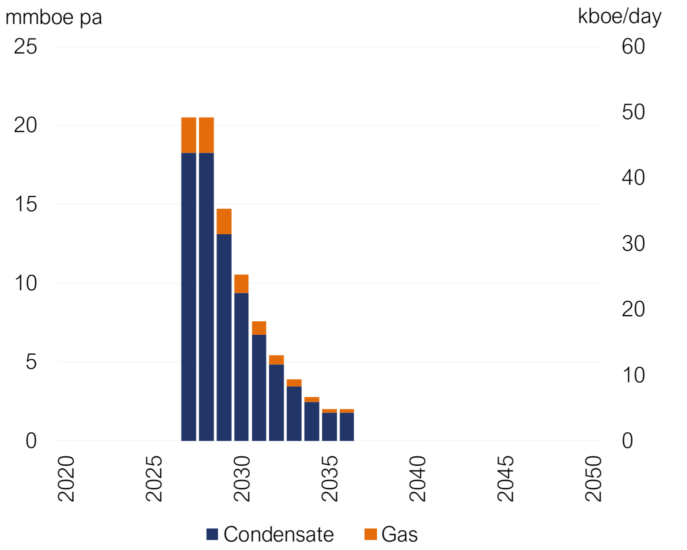
## KEY ASSUMPTIONS

| | | |
|---|---|---|
| Commissioning year | Year | 2027 |
| Produced - condensate | mmbbl | 80 |
| Produced - gas | PJ | 63 |
| Produced - condensate+gas | mmboe | 90 |
| Plateau - condensate | kbbl/day | 50 |
| Plateau - gas | TJ/day | 40 |
| Plateau - condensate+gas | kboe/day | 56 |
| Long-term Brent | US$/bbl | 65.0 |
| Pc | % | 33% |
| Long-term USD/NZD | $ | 0.640 |
| DHC | US$m | 30 |
| Development capex | US$m | 1,530 |
| Development capex | US$/boe | 17.0 |
| Opex | US$/boe | 10.0 |

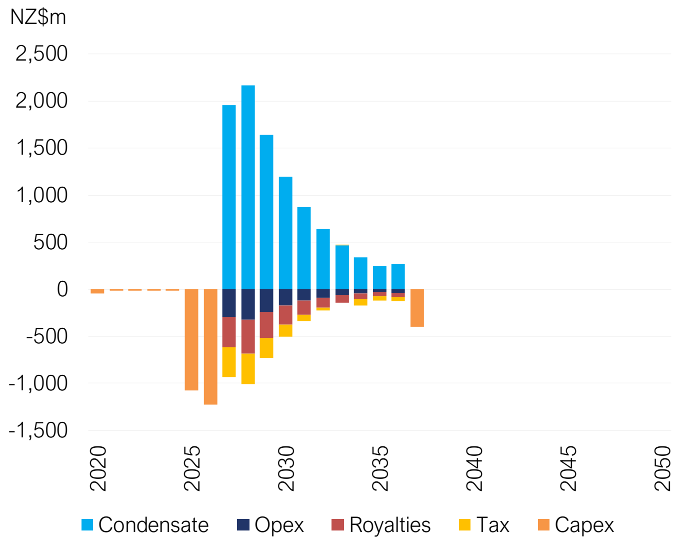
## INVESTMENT RETURNS

| Unrisked project returns | | | |
|---|---|---|---|
| NPV10 | NZ$m | 687 | |
| NPV10 | US$m | 440 | |
| IRR nominal | % | 23.1% | |
| RTEP | % | 20.6% | |
| VIR | x | 0.47 | |
| DPP | Years | 9 | |
| **Government take** | | | |
| Royalties PV | NZ$m | 905 | |
| Tax PV | NZ$m | 771 | |
| Total PV | NZ$m | 1,676 | |
| **Risked EMVs** | | JV | Crown |
| Success case EMV | NZ$m | 229 | 559 |
| Failure case EMV | NZ$m | -31 | -15 |
| EMV | NZ$m | 198 | 544 |

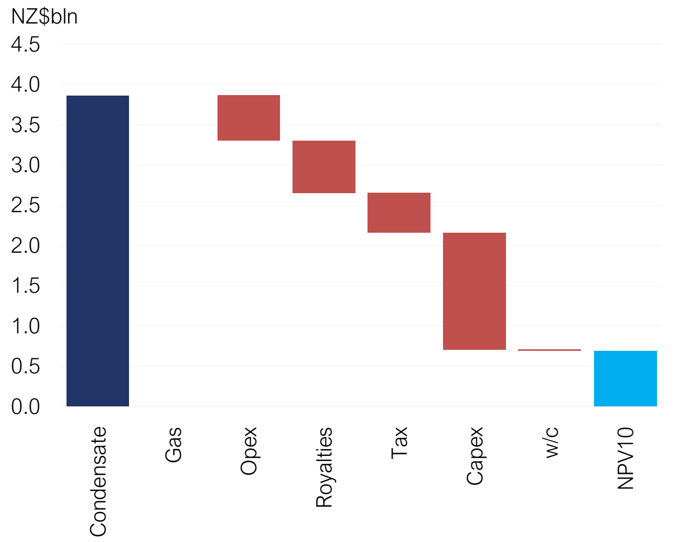
## PRODUCTION



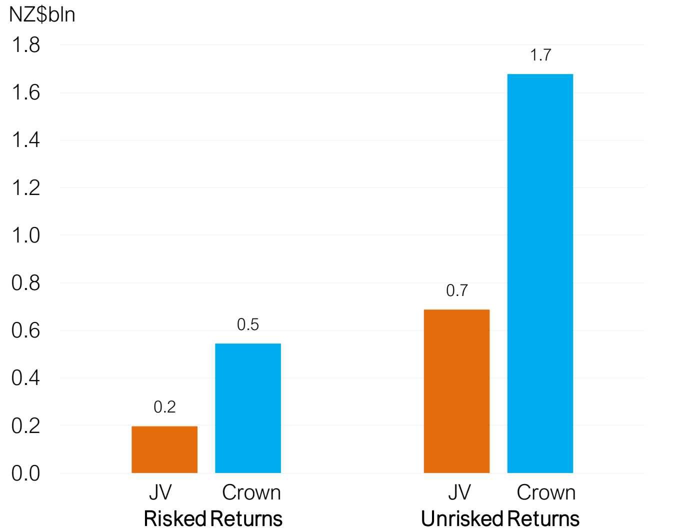

## CASH FLOW PROFILE




## SHAREHOLDER NPV10 CONSTITUENTS




## STAKEHOLDER RETURNS




Source: Enerlytica

# Maui

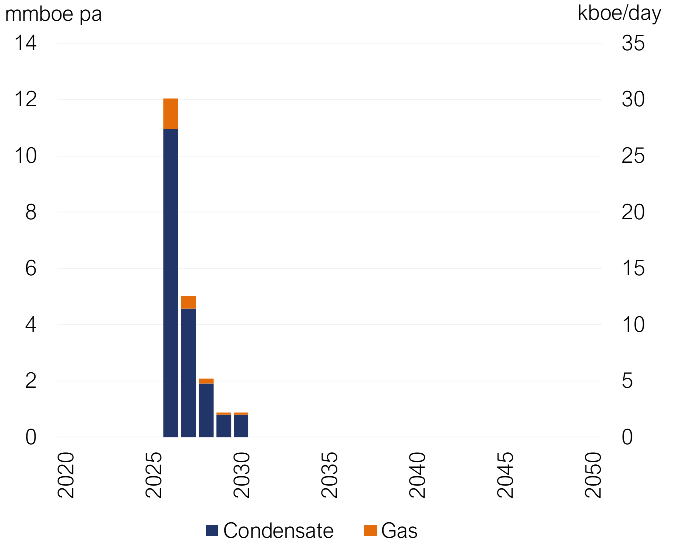
## KEY ASSUMPTIONS

| | | |
|---|---|---|
| Commissioning year | Year | 2026 |
| Produced - condensate | mmbbl | 19 |
| Produced - gas | PJ | 12 |
| Produced - condensate+gas | mmboe | 21 |
| Plateau - condensate | kbbl/day | 30 |
| Plateau - gas | TJ/day | 19 |
| Plateau - condensate+gas | kboe/day | 33 |
| Long-term Brent | US$/bbl | 65.0 |
| Pc | % | 33% |
| Long-term USD/NZD | $ | 0.640 |
| DHC | US$m | 25 |
| Development capex | US$m | 522 |
| Development capex | US$/boe | 25.0 |
| Opex | US$/boe | 2.5 |

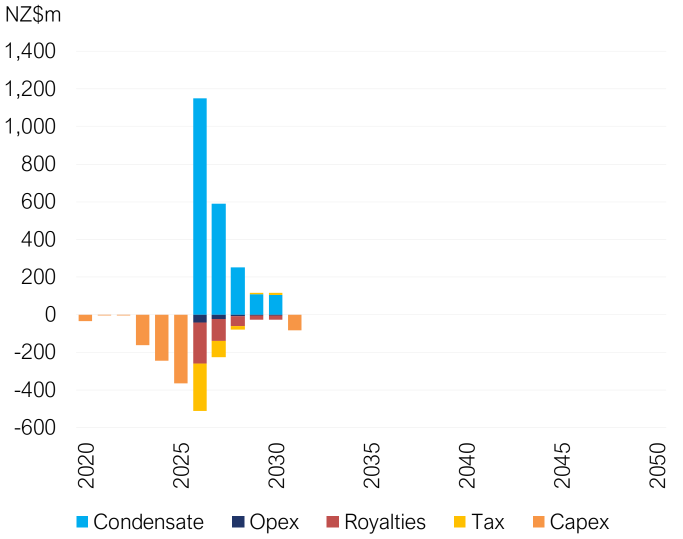
## INVESTMENT RETURNS

| Unrisked project returns | | | |
|---|---|---|---|
| NPV10 | NZ$m | 150 | |
| NPV10 | US$m | 96 | |
| IRR nominal | % | 20.1% | |
| RTEP | % | 17.7% | |
| VIR | x | 0.27 | |
| DPP | Years | 7 | |
| **Government take** | | | |
| Royalties PV | NZ$m | 268 | |
| Tax PV | NZ$m | 243 | |
| Total PV | NZ$m | 512 | |
| **Risked EMVs** | | JV | Crown |
| Success case EMV | NZ$m | 50 | 171 |
| Failure case EMV | NZ$m | -26 | -9 |
| EMV | NZ$m | 24 | 162 |

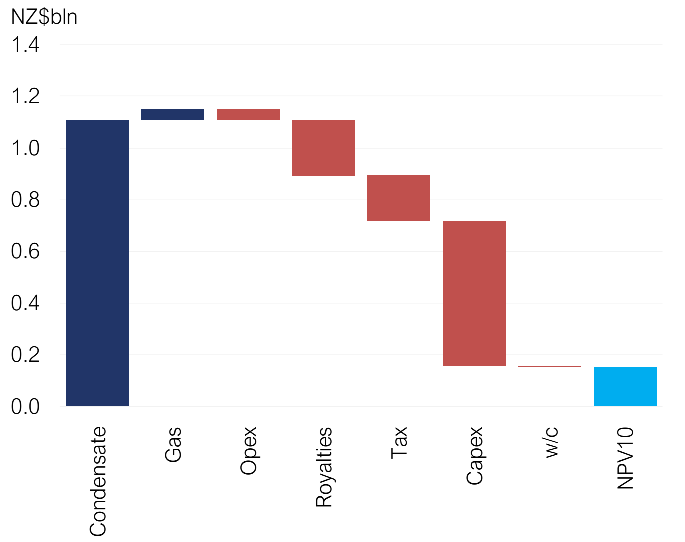
## PRODUCTION



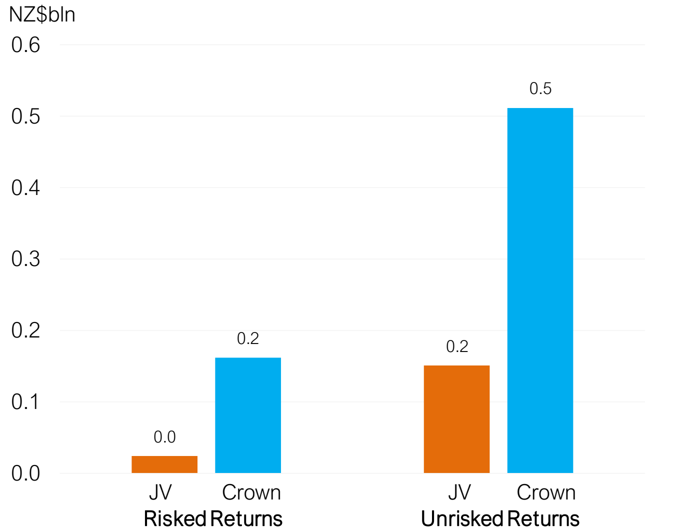

## CASH FLOW PROFILE




## SHAREHOLDER NPV10 CONSTITUENTS

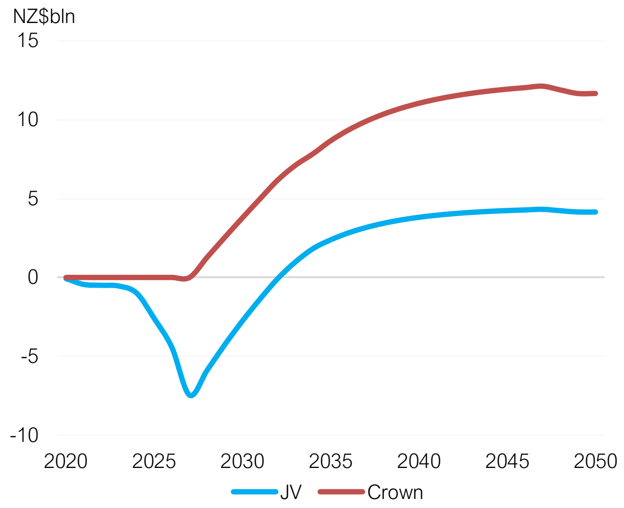



## STAKEHOLDER RETURNS



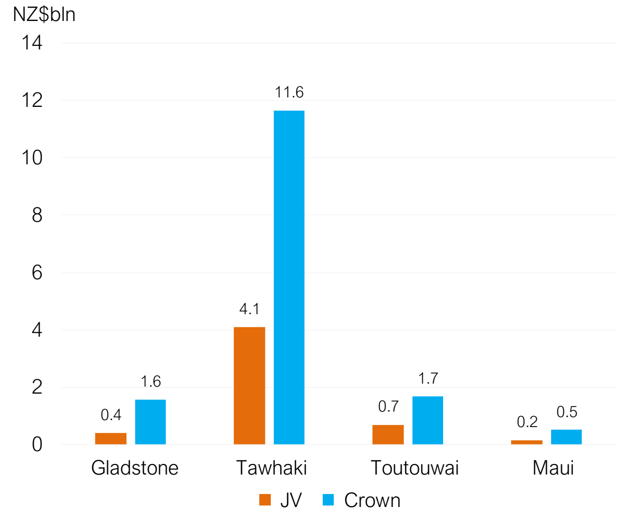

Source: Enerlytica

**Tawhaki success case PVs of stakeholder returns**



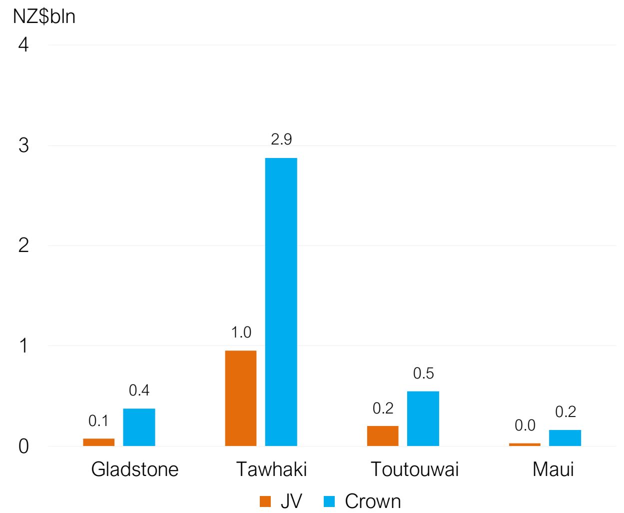

Source: Enerlytica

**Unrisked prospect success case stakeholder returns**




Source: Enerlytica

**Risked prospect success case stakeholder returns**




Source: Enerlytica

# 2. Macroeconomic Benefits

## Energy Trilemma

A widely used tool for analysing the balance of energy systems across different countries is the Energy Trilemma developed by the World Energy Council (WEC). The Trilemma scores energy outcomes across dimensions of energy security, energy equity/affordability and environmental sustainability which are then benchmarked against the scores of other countries.

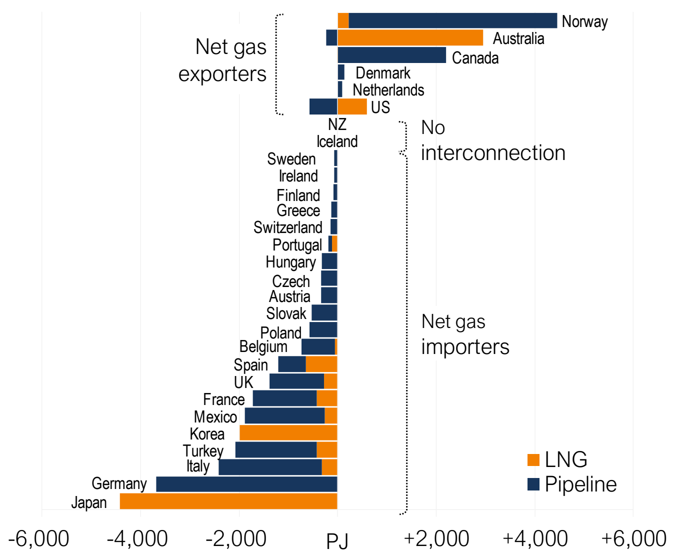
NZ has consistently ranked highly on the index and in 2019 was the only non-EU country to rank in the top 10 from a total 128 nations. A key contributor to NZ's high ranking is its renewables-heavy electricity sector and relatively high fuel self-sufficiency.

### i. Security of Supply

Security of energy supply refers to a country's capacity to reliably meet its current and future energy demand. WEC criteria focuses on the availability of indigenous fuel supply to meet indigenous energy demand, diversity in electricity generation and energy storage. NZ's profile is defined by a large and still growing backbone of renewable fuel electricity generation (hydro, geothermal, wind) but also an important but declining stock of indigenous thermal fuel (oil, gas and accessible coal).

For NZ, which is one of the most physically remote and least energy-connected nations in the world, declining stocks of indigenous thermal fuel has in recent years left domestic steelmakers and electricity generators with no option but to import fuel to meet domestic demand.

**OECD nation cross-border gas trade**




Source: BP Statistical Review of World Energy, Enerlytica

## NZ coal imports

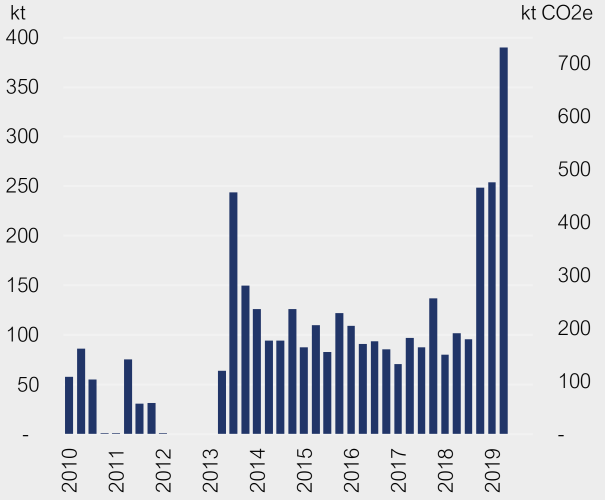
NZ is typically a significant net-exporter of coal due to the contribution of large mining operations on the West Coast of the South Island which produces mostly high value coking coal to sell to steelmakers on the export market. As there is no indigenous gas in the South Island, lower grade thermal coal is also widely used in industrial, commercial and domestic markets.

The North Island also has a significant domestic coal sector that supplies industrial and commercial users. Of these the largest user is the NZ Steel mill at Glenbrook which uses up to 800 ktpa. Due to capacity constraints only around half of this can be supplied domestically from local fields, leaving the balance to be procured from international markets and imported into the ports of Auckland and Tauranga from where it is trucked to Glenbrook.

The next largest user in a normal year is Genesis Energy which buys coal to support the operation of its 750 MW dual-fuel gas and/or coal power station at Huntly. In a normal year Genesis will buy ~300 ktpa (~7 PJ pa) of local Waikato coal from supplier BT Mining. During 2018 two dry hydro sequences and two extended unscheduled part-outages of the Pohokura field disrupted supply into the North Island gas market causing major users to either source alternative fuel lines to substitute for undelivered supply or curtail their gas demand. Unable to substitute with local coal, to meet peak electricity demand Genesis imported more than 600 kt of Indonesian coal leading into winter 2019.

The result is that, due to domestic gas and coal fuel supply constraints, NZ imported 1 mt of coal during 2018 to meet domestic supply shortages and to ensure security of domestic electricity supply. With the imports came 2.2 mt of $CO_2e$ which at current carbon prices equates to $55m of additional cost for electricity purchasers to incur.

**NZ sub-bituminous coal & associated $CO_2e$ imports, quarterly**




During 2018 successive weak hydro sequences, two major unscheduled outages at NZ's largest gas field and supply constraints in the Waikato coal fields saw NZ Steel and Genesis import large volumes of Asian coal to meet demand. The result was that leading into winter 2019 NZ imported 1.1 million tonnes of coal, the first time since 2006 that NZ has imported more than 1 mtpa of coal. 2006 was coincidentally also the last year that NZ registered a new gas discovery with the onshore and comparatively small Kowhai field.

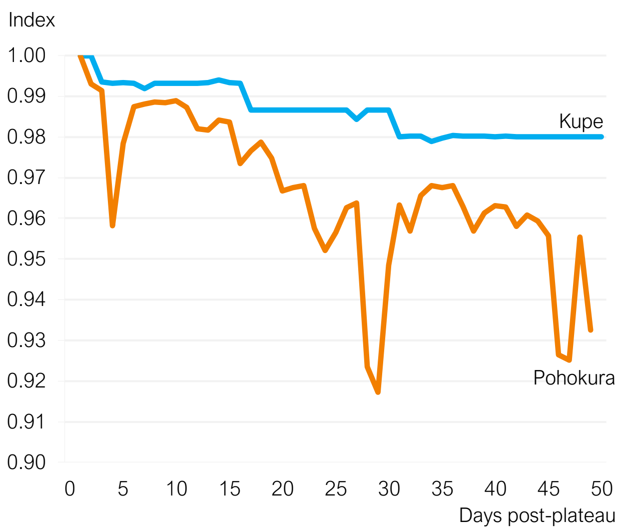
## Deliverability

An important aspect of security of gas supply is that of deliverability, which is the system's ability to supply gas on a dynamic (eg hourly, daily) basis as it is needed. Deliverability is very different to the more widely referenced concept of reserves, which is an absolute estimate of total resource endowment.

Declining system deliverability and flexibility has been a feature of the sector for the past decade. While until recently this trend has centred on the Maui field, it is now broadening to other large fields which due to depletion are also now entering deliverability decline. In August, Kupe operator Beach Energy informed its JV partners that after 10 years of production Kupe had left plateau and that future production was expected to reduce by between 1.0% and 1.5% per month.

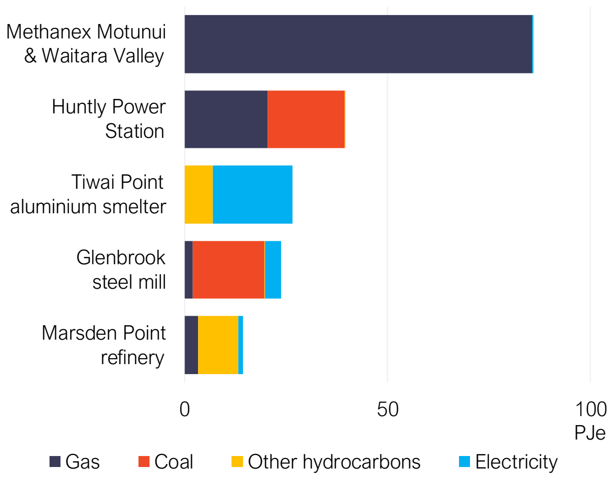
Pohokura, which has been in continuous production since 2006, also appears to have exited plateau, although the downwards trend evident in carriage data may be distorted by intra-year gas washup arrangements within the JV. Notwithstanding this, the downwards trend in deliverability during the two major turn-down periods in 2018 suggested underlying decline in reservoir performance.

**Kupe & Pohokura 50-day post-plateau gas deliveries**




Source: OATIS data, Enerlytica

**NZ energy-intensive site fuel profiles**




Source: Enerlytica

The decline in forward gas system deliverability is already evident in the operating decisions and outlooks for some major energy users. The market's largest gas user (and in fact by some distance NZ's largest energy user across all formats) is Methanex. Methanex is a major but very low-profile exporter of NZ-produced methanol into the Asian market. From its three large plants that it operates near New Plymouth, in a normal year Methanex accounts for around 45% of gas market demand.

Methanol is a low-emission, clean-burning alcohol that is used in the manufacture of countless everyday products including building materials, plastics, paints, foams, resins and health products. The strongest growth market however is as a direct feed into the fuel pool to blend with or even substitute for more pollutive fuel formats including petrol, diesel, fuel oil and coal.

Methanex typically contributes $1.3 bln pa of export receipts and independent research has concluded annual GDP contribution of $834m pa – each materially higher than the value equivalents for the Tiwai Point aluminium smelter.

In October, Methanex announced that it expected to operate its NZ plants at only 80% of capacity in 2020 due to gas availability constraints, saying "*While there is significant field development work underway in the upstream sector, we do not expect to see the benefit of this next year*." This demonstrates the current importance of gas system deliverability (and not reserves) in driving the operating decisions of major users.

To address their respective decline curves, each of the Pohokura and Kupe JVs have committed to separate inlet compression projects for likely spends of $70m apiece. The Pohokura compression project should be completed in mid-2020 and Kupe in mid-2021.

Compression expansion is a standard response for mid-life fields but serves only to defer terminal decline. The next round of investment will likely involve further development drilling to increase the field area and recovery rates. As the recent experience at Tui has shown, drilling – even what is considered by investors to be high probability infill drilling – is very much more expensive and carries a much greater risk exposure than work above-ground to debottleneck existing facilities and infrastructure.

The Maui crestal programme is similarly representative of the type of work that is required to lift deliverability and reserves to extend the life of deeply mature fields. At a cost of more than $200m, it is also indicative of the extent of investment required to complete.

### Key observations relating to energy security:

- Declining indigenous thermal fuel availability (meaning deliverability) is leaving large industrial gas users with no alternative but to import more carbon-intensive fuel from overseas at substantial additional cost.
- If successful, and if gas rich, the Taranaki Basin component of the OMV-led programme would add much needed new supply capacity to the North Island gas market. Success would materially improve security of domestic energy supply and dull the inevitable medium-term market impact that the decommissioning of Maui would inflict.
- NZ has not had a new gas discovery since 2006. In the ongoing absence of a significant new gas discovery, emphasis will fall on reinvestment programmes targeting existing offshore and onshore fields to support deliverability decline. Despite being lower risk, these programmes are very expensive and require the commitment of substantial new development capital.
- The gas system users that are most exposed to deliverability are large petrochemical producers (Methanex in particular), electricity generators (Genesis Energy and Contact Energy) and industrial and commercial users (Fonterra, NZ Steel, Refining NZ, Oji Fibre Solutions among others). Domestic and commercial users do not face these same physical supply pressures but do face the likelihood of increasing energy prices if supply constraints continue.
- Whether exploration success at Tawhaki would translate to a physical connection to shore and therefore existing energy markets would not become clear for a number of years. Whether or not a physical connection did materialise would not alter a conclusion of substantial economic benefits from a commercial development.

## ii. Energy affordability

Energy affordability refers to a country's capacity to provide access to affordable energy. In its benchmarking the WEC scores access to electricity, electricity prices and oil product (petrol and diesel) prices. As there is universal access to electricity in NZ, focus locally centres on energy affordability. Whereas the Security of Supply dimension refers to the absolute availability of *physical* energy, which isn't typically constrained in NZ, the concept of affordability can be thought of as representing *economic* security of supply, in that it accounts instead to the relative cost of physical energy.

In the electricity sector, due to their high fuel and operating costs, gas and coal fired generating plant sits at or near the bottom of the generation dispatch merit order with the highest SRMC. When hydro dispatch is constrained by low storage, thermal firming is called on to balance the market. This increases the spot settlement price for the entire market, representing the market's indifference to the source of stored fuel. Times of scarcity pricing on thermal fuel therefore leads directly to higher spot electricity prices.

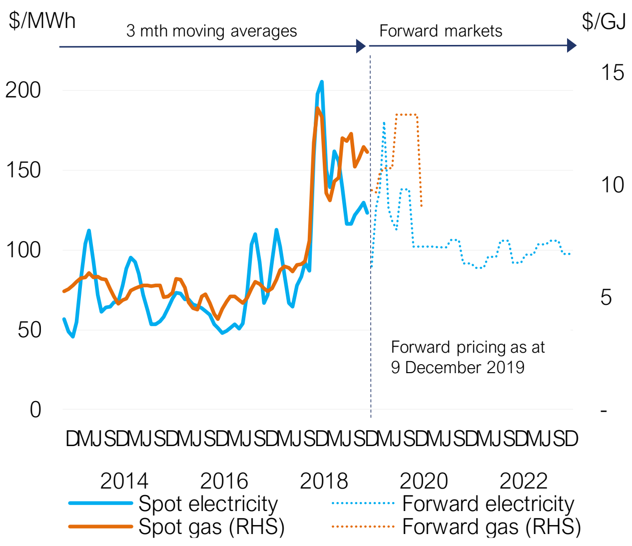
The correlation between spot gas and spot electricity prices since 2013 when the spot gas market launched is very strong ($R^2$ of 0.95 on a rolling 12-month basis). For electricity market participants this has meant that the >85% increase in spot gas prices seen since 1Q 2018 has been relayed directly to spot electricity prices which have surged >75% over the same timeframe.

The increse in spot and forward gas and electricity pricing since mid-2018 is being passed through to end users. As their own supply arrangements tend to be pegged to futures pricing it has been large industrial and commercial (I&C) users that have been the first to suffer. In most cases I&C users that are rolling off existing 2-3 year gas and/or electricity contracts are facing price increases of greater than 50%. Mass market and residential consumers have been largely insulated until now in part by vertical integration of the largest retailers. This is not sustainable however as under current conditions the retail units of these businesses will be suffering heavy losses – a conclusion that will become more transparent as a result of one of the outcomes of the Government's recently-concluded Electricity Price Review which will require vertically integrated generator/retailers to report separate financial results for each of their generation and retail businesses.

### Relief from gas and electricity tightness

Looking ahead, the tight gas market conditions appear likely to persist until at least the end of 2020. Beyond that, loosening will require one of two thematic shifts to occur for the status quo ~200 PJ pa gas market to prevail: either additional supply capacity will need to be brought onstream or a material wedge of demand will need to temporarily or permanently exit the market.

**Wholesale electricity vs gas market prices**




Source: EA & emsTradepoint data, Enerlytica

There are clearly pathways for each or possibly even both scenarios to materialise. Ahead of that, higher gas and, therefore, electricity prices appear likely to be a central energy sector theme for at least 2020. With that will come lower economic growth and productivity as large energy users for which higher prices may not be sustainable may look to curtail or close their operations. Indeed, this is precisely the market scenario that Rio Tinto has flagged with its 'strategic review' of its Tiwai Point operation.

### Key observations relating to energy affordability:

- Energy equity and energy affordability can be thought of as one of the same in NZ where the population already effectively has universal access to energy.
- Supply constraints affecting renewable (largely hydro) and thermal (largely gas) fuel availability since mid-2018 have combined to elicit large increases in gas and electricity price benchmarks. Forward markets are signalling that the distress of 2018-19 is likely to continue into at least 2020. The underlying issue is tight thermal fuel availability which is causing operators of marginal plant to seek and secure alternative fuels from export markets to meet domestic demand. These fuels are more expensive in both financial and environmental terms than their domestic alternatives, the cost of which is being passed through to consumers.
- The Taranaki Basin component of the OMV-led programme would, if successful and if gas-rich, be likely to increase gas availability and market liquidity by bringing new supply-side capacity to market. This would support the retention of existing demand and, as a result, keep downwards pressure on prices compared to what would be the case if supply conditions remain as they currently are and the balancing of demand remains under pressure.

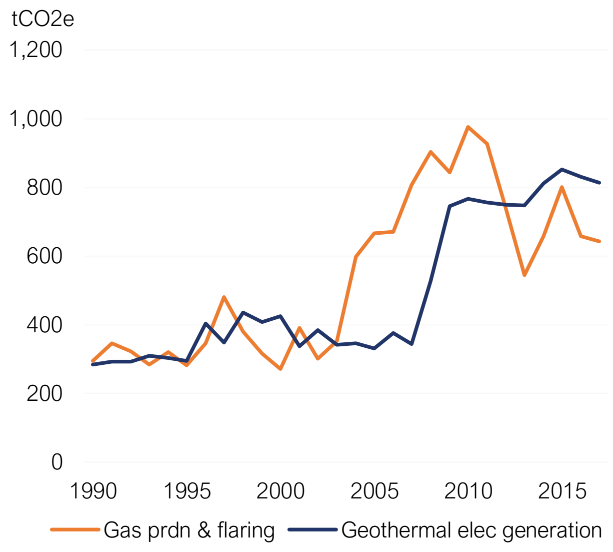
- Success at Tawhaki would be likely to have a material albeit indirect impact on NZ's energy affordability. Although a development at Tawhaki would more likely than not be physically disconnected from the mainland and therefore existing domestic energy markets, the benefits that would accrue from a development would nonetheless be substantial. As well as increased Government Take adding a significant and long-term new layer to the Crown's revenue base, benefits would include the addition of new and highly skilled jobs to the regions, higher export receipts and therefore balance of payments benefits, a stronger currency and higher economic growth. Returns would provide options to deploy dividends, including towards the decarbonisation of more emissions-intensive areas of the economy.

## iii. Energy sustainability

Energy sustainability refers to a country's progress with mitigating and avoiding potential environmental harm and climate change impacts. WEC tracks energy intensity (energy demand as a function of GDP), low-carbon electricity generation and $CO_2$ emission intensity (per capita emissions) in its scoring.

NZ scores strongly for its low-carbon generation backbone (the third lowest in the OECD) but mid-range for energy intensity and $CO_2$ intensity. The middling intensity results are unsurprising given the presence of a number of legacy large-footprint energy-intensive industries. Also a factor will be the rapid growth in geothermal generating capacity over the past decade. Geothermal generation, while renewable, can also often be accompanied by a material $CO_2$ component.

**Upstream gas production vs geothermal generation $CO_2e$ emissions**




Source: MBIE data, Enerlytica

NZ's heaviest-emitting geothermal plant is the 105 MW (gross) Ohaaki power station which has an emissions factor of 341g $CO_2e$/kWh which is only 10-15% lower than the equivalent emissions factor for Genesis Energy's Huntly combined cycle gas turbine. On a gross basis, emissions produced from gas production and flaring are broadly comparable to emissions produced by geothermal electricity generation.

### Gas as higher-rank fill for coal and liquid fuels

The events of 2018-19 have demonstrated the importance of gas in the energy system to serve as a lower-emission, lower-cost, higher-reliability fuel during times when more attractive fuels (water, wind, geothermal steam and sun) are constrained. If gas is not available to balance the market then buyers that are able to keep moving down the fuel merit order until an option does become available. Buyers that are not able to take alternatives have no option but to curtail production.

Genesis Energy's 2018-19 coal procurement programme demonstrated clearly the role of gas in minimising the call on coal to balance electricity supply with demand. If the 605 kt of imported coal had instead been able to have been supplied by domestic gas then more than 500,000 tonnes of $CO_2e$ emissions would have been avoided in direct fuel burn alone. Atop this, significantly more would have been saved by avoiding the extended transport chain involved with transporting coal from Indonesia to Huntly.

Fonterra is another user that has been vocal about the impact to its business of gas supply disruptions. At a number of its North Island dairy factory sites it maintains dual fuel infrastructure that provides diesel backup to cover gas outages and shortages. As well as being substantially more expensive, burning diesel in place of gas emits considerably more $CO_2e$ per unit of heat produced. Furthermore, in a worst case scenario where a gas disruption required diesel to substitute in full for gas supply, Fonterra's diesel demand would increase by 1.1 million litres per day – a volume that would see NZ's national stock of diesel depleted in the space of about a week.

Methanex provides a further example. It operates a fleet of methanol-fuelled vessels to transport methanol it produces from across its global portfolio to export markets. These new carriers are in place of traditional maritime carriers that run on lower-grade fuels such as heavy fuel oil (HFO) and diesel. By comparison HFO is a highly pollutive alternative that emits far higher components of $CO_2e$ and particulates.

More broadly, Methanex's export of NZ-origined methanol to large Asian markets including China, South Korea and Japan serves to support decarbonisation efforts in the region. As a gas-based, clean-burning fuel alternative methanol also contributes significantly to improving urban air quality in those countries.

Key observations relating to energy sustainability:

- NZ's E&P sector is relatively emission-efficient compared to other jurisdictions. In the event of a new discovery it is likely that CCS would feature as part of the FDP which would further reduce fugitive emissions from the sector.
- Gas is a highly attractive alternative to higher-emitting fuel formats, in particular coal and liquid fuels which emit much higher relative quantities of both $CO_2e$ and atmospheric particulates. Methanol is valued in major Asian markets for these qualities. A new gas-rich discovery in the Taranaki Basin would provide significant support to Methanex's longer-term viability in NZ. A new gas-rich discovery at Tawhaki would enable NZ to contribute new capacity into the Asian market to help with decarbonisation and reduce the current reliance on coal and liquid transport fuels.
- Domestic gas supply constraints have the effect of shifting the burden of balancing demand to lower-ranked thermal fuels, meaning coal and refined oil products such as diesel.
- Gas serves as a strong enabler of renewable electricity generation build, many formats of which require load firming to cover intermittency. Wind generation in particular requires the support of standby fast-start capacity, which gas-fired peaking and mid-merit plant is ideally placed to provide.
- The Taranaki Basin component of OMV's programme is important towards increasing gas availability and, therefore, the ability of the NZ energy system to support the weight of its heavy renewable energy base without needing to resort to low-ranking fuel alternatives such as coal and diesel.

## GDP BENEFITS

The estimates for Government Take accounts only for direct royalties and taxes received by the Crown and do not account for wider benefits to the economy that development of one or more discoveries would deliver.

The quantifying of macroeconomic benefits is beyond the scope of this analysis, however past independent analysis has provided an indication of the macroeconomic benefits that could follow such a development. The most relevant is a 2017 Martin Jenkins analysis that estimated what the development of a large discovery in the Canterbury Basin could contribute to NZ's macroeconomy. That study concluded that a oil-rich discovery could over a 35-year economic life generate:

- Total recoverable oil of 460 mmbbl
- Average annual production of 18.1 mmbbl for average annual revenue of NZ$1.8 bln
- Average annual royalty payments of $270m for a total of $9.7 bln over the project's life
- Average annual corporate tax payments of $300m for a total of $10.5 bln over the project's life
- Average annual GDP of $236m for a total $8.3 bln over the project's life.
- Average annual jobs created 3,650.

Martin Jenkins also modelled a scenario where a gas-rich discovery is relayed to an onshore production facility where greenfield methanol and urea plants are also assumed to be built. In this case macroeconomic benefits were broadly between 50% and 100% higher than for the offshore scenario estimates.

# GLOSSARY

| | |
|---|---|
| 2D | two-dimensional |
| 3D | three-dimensional |
| 2P | proved and probable petroleum reserves, also referred to as P50 reserves |
| appraisal well | a well drilled to determine the size of an oil or gas discovery |
| APR | Accounting Profits Royalty |
| associated gas | gas that is produced in association with oil or condensate and separated in the production process |
| AVR | Ad Valorem Royalty |
| baseload | electricity generation plant used to meet some or all of continuous electricity demand, and produce at a constant rate, usually at a low cost relative to other generation options available to the system |
| bbl | barrel, equal to 42 US gallons or 158.987 litres |
| boe | barrel of oil equivalent |
| boepd | barrels of oil equivalent per day |
| bopd | barrels of oil per day |
| Brent crude | a major oil marker price for sweet light crude oil and the leading global price benchmark for Atlantic basin crude oils.  Almost 70% of the world's internationally traded crude, including most New Zealand crude, is priced against a Brent crude benchmark. |
| CAGR | compound annual growth rate |
| capex | capital expenditure |
| CCGT | combined cycle gas turbine |
| CCS / CCUS | carbon capture and storage / carbon capture, use and storage |
| CMA | Crown Minerals Act |
| CNG | compressed natural gas, being natural gas that has been compressed or contained under pressure |
| $CO_2$ | carbon dioxide |
| condensate | light hydrocarbon compounds of low density and high API gravity that normally exist in a reservoir as gas but condense to a liquid during production |
| crude | see *oil* |
| D&A | depreciation and amortisation |
| DCF | discounted cash flow |
| deep water | water depths of between 300m and 1,500m |
| development well | a well drilled to enable production from a known oil or gas reservoir or deposit |
| DHC | dry hole cost |
| DPS | dynamic positioning system |
| € | Euro |
| ECS | Extended Continental Shelf |
| EEZ | Exclusive Economic Zone |
| EMV | expected monetary value |
| EOR | enhanced oil recovery |
| E&P | exploration and production |
| EPA | Environmental Protection Agency |
| EPC | engineer, procure, construct |
| ERL | Energy Resources Levy |
| ETS | emissions trading scheme |
| exploration well | a well drilled seeking new, undiscovered petroleum deposits |
| FCF | free cash flows |
| FID | final investment decision, being the decision point at which a venture's sponsors give their commitment to sanction and develop the venture |
| FLNG | floating LNG |
| FDP | field development plan |
| FPSO | floating production, storage and offloading vessel |
| gas | a naturally occurring hydrocarbon consisting primarily of methane |
| GDP | gross domestic product |
| GJ | gigajoule ($10^9$ joules) |
| GSA | gas sale agreement |

| | |
|---|---|
| **GST** | goods and services tax |
| **GWh** | gigawatt hour |
| **HFO** | heavy fuel oil |
| **hydrocarbons** | an organic compound consisting entirely of hydrogen and carbon, the majority of natural variations of which occur in crude oil |
| **I&C** | industrial and commercial |
| **IRR** | internal rate of return |
| **joule** | A unit of energy, equal to 1/3600 of a kWh |
| **JV** | joint venture |
| **km$^2$** | square kilometres |
| **kt** | thousand tonnes |
| **ktpa** | thousand tonnes per annum |
| **kWh** | kilowatt hour |
| **LNG** | liquefied natural gas |
| **LPG** | liquefied petroleum gas, being mainly propane ($C_3$) or butane ($C_4$) or a mixture of both |
| **LRMC** | long run marginal cost |
| **m** | million |
| **MBIE** | Ministry of Business, Innovation and Employment |
| **MEFS** | minimum economic field size |
| **methanol** | methyl alcohol ($CH_3OH$), a colourless liquid produced from natural gas and is the raw material for many chemicals, formaldehyde, dimethyl terephthalate |
| **mmboe** | million barrels of oil equivalent |
| **MODU** | mobile offshore drilling unit, more generically known as an offshore oil rig |
| **mt** | million tonnes |
| **mtpa** | million tonnes per annum |
| **MW** | megawatt ($10^6$ watts) |
| **natural gas** | a term most commonly used to describe gas that meets specification standards to be injected into a pipeline for reticulation to end users. In New Zealand, the specification for reticulated natural gas is set out in national standard NZS 5442 |
| **NPV** | net present value |
| **NPV10** | net present value at an assumed discount rate of 10% on a nominal post-tax basis |
| **NZP&M** | New Zealand Petroleum and Minerals, a division of MED responsible for administering the Crown's oil, gas, minerals and coal resources |
| **OATIS** | Open Access Transmission Information System, the pipeline operation system which facilitates third party access to the Maui Pipeline |
| **OCGT** | open cycle gas turbine |
| **oil** | a generic term to describe oil products in various forms including crude oil, condensate and naphtha. In this report the term *oil* is used interchangeably with *condensate* and *crude* |
| **opex** | operating expenditure |
| **pa** | per annum |
| **PEP** | Petroleum Exploration Permit |
| **$P_c$** | probability of commercial success |
| **peaking plant** | electricity generation plant operated expressly for the purpose of providing electricity into the market during periods of peak demand, usually at a higher cost relative to other generation options available to the system |
| **$P_g$** | probability of geological success |
| **PIIP** | petroleum initially in place |
| **PJ** | petajoule ($10^{15}$ joules) |
| **PMP** | Petroleum Mining Permit |
| **PV** | present value |
| **reserves** | the portion of PIIP that is at a specified date economic to develop and extract under a given set of technical, commercial and economic assumptions |
| **resource** | the portion of PIIP that is not economic to develop and extract under the same assumption set. |
| **reservoir** | rock that is charged with hydrocarbons and both porous and permeable |
| **RTEP** | real terms earning power |
| **SRMC** | short run marginal cost |
| **t** | tonnes |
| **TCC** | Taranaki Combined Cycle power station owned and operated by Contact Energy |
| **TJ** | terajoule ($10^{12}$ joules) |

| | |
|---|---|
| ToR | terms of reference |
| tpa | tonnes per annum |
| URR | ultimate recoverable reserves |
| US$ | United States dollars |
| VIR | value investment ratio |
| VWAP | volume weighted average share price |
| WACC | weighted average cost of capital |

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independence | intelligence | insight