AUSTRALIAN LNG – FROM EXPORTER TO IMPORTER

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AGL is preparing to develop Australia’s first LNG import project (FSRU), in the country’s southeast. The project is designed to meet a supply and structural shortfalls in the east coast domestic market.

In 2018-19, Australia will become the world’s largest exporter of LNG. The growth has come from a rapid increase in liquefaction capacity in the northwest and northeast of the country. At the same time that export projects draw in supply, domestic markets in the high population centres in the southeast are seeing a decline in production from traditional sources, such that without new sources of gas supply to domestic users, a market shortfall is forecast to commence from 2022.

AGL is a retailer and wholesaler of gas and a generator of electricity. Facing the looming threat of a domestic gas supply shortage, AGL initiated a feasibility study in 2016 to develop Australia’s first ever LNG import and regasification project.

To date (April 2018) a site has been announced, and LNG suppliers and FSRU candidates shortlisted. A preferred pipeline partner has been engaged and extensive environmental studies undertaken in preparation of key regulatory approvals.

AGL’s proposed presentation will explain:
- how Australia came to be in a position to become the world’s largest LNG exporter and newest importer.
- how AGL’s project, targeting FID in 2018-19 and first gas in 2020-21, makes commercial sense, and provides a flexible solution, and
- the challenges faced and solutions proposed for operation of the FSRUs to provide long term energy security to Australian energy users.
INTRODUCTION

In 2019, Australia is expected to be the world’s largest exporter of Liquefied Natural Gas (LNG). The growth has come from a rapid increase in liquefaction capacity in the northwest and northeast of the country. At the same time that the LNG export projects draw on both their own reserves and gas supply from the broader domestic market, gas markets in the high population centres in the southeast of the country are facing a decline in production from traditional gas supply sources. As a result, without new sources of gas supply, domestic users face a market shortfall, predicted to commence around 2021-22.

AGL Energy Limited (AGL) is one of Australia’s largest utility companies with 180 years of experience and around 3.6 million customer accounts, including 1.4 million gas connections. AGL is a retailer and wholesaler of gas and a generator of electricity with approximately 10,620MW of generation capacity across renewables and gas and coal-fired generation.

To address the looming threat of a domestic gas supply shortage and increasing constraints in the gas transmission infrastructure, AGL initiated a feasibility study in 2016 to commence the development of Australia’s first LNG import and regasification project. The AGL gas import jetty project will utilise a Floating Storage and Regasification Unit (FSRU) moored at the Crib Point Jetty, Western Port, Victoria. Located around 65 kilometres from Melbourne, a major population and demand centre with over 4.8 million residents, and almost 20% of the country’s population, the site is well placed to receive imported LNG for injection into the local market.

To date, AGL has achieved a number of key milestones in progressing the project. The preferred LNG import site was announced in August 2017, key agreements with the port and pipeline partner were executed in June 2018, LNG suppliers shortlisted and a 10-year time charterparty agreement for supply of an FSRU was executed in December 2018. In conjunction with the selected pipeline partner, extensive environmental studies have been undertaken in support of key regulatory approvals, including the Environmental Effects statement, or “EES” that is currently in progress (EES).

This paper will provide an overview of the AGL gas import jetty project and address the question of:

- how Australia came to be the world’s largest LNG exporter and is likely to be one of the newest importers;
- how AGL’s project, targeting first gas in 2021, provides a new source of flexible gas supply to the market that will put downward pressure on prices and ensure security of supply of gas to domestic consumers.

EXPORTER TO IMPORTER: AUSTRALIA’S GAS STORY

Australia is a country blessed with an abundance of natural resources. Its gas reserves have been more than what is required for its domestic population, resulting in a robust commercial basis for accelerated monetization of these gas resource through LNG exports to the international market.

The commissioning of numerous LNG export projects in recent years, including Queensland’s onshore coal seam gas projects, the Ichthys project piping gas from Western Australia to Darwin and the Prelude Floating LNG project, offshore on the north west coast of Australia together with existing LNG export projects, culminated in Australia becoming the world’s largest exporter of LNG with an annual export quantity of more than 77mtpa expected in 2019.

With such an abundance of gas, why does Australia need to import gas? To answer this question, we need to take a closer look at Australia’s domestic gas market.

Australia’s east coast domestic gas market

Due to the vast distance across the continent, Australia’s largest population centres in the east are not connected to the gas reserves and LNG production plants in the northwest. The east coast market has only connected from
Queensland in the northeast, down to Melbourne and Tasmania at the south-eastern tip of the country. Most recently, with the addition of the Northern Gas Pipeline, the east coast gas network is now connected to gas reserves in the Northern Territory.

The figure below highlights in yellow the location of demand centres in the most densely populated, and colder, south-eastern states in Victoria, New South Wales and South Australia compared with the location of the most abundant gas reserves serving LNG export facilities in the north west and north east of the country.

Figure 1. Demand centres vs major gas reserves locations.

Examination of gas demand on a state by state basis for the southern states highlights that Victoria’s demand for gas is significantly higher than New South Wales and South Australia combined.
The major source of supply for Victoria since the 1960’s has come from the gas rich basins in its offshore waters, namely the larger Gippsland Basin and smaller Otway and Bass Basins. The abundance of gas from these basins also led to the development of pipelines north to supply Sydney in New South Wales, and west to Adelaide in South Australia supplementing supply from onshore South Australian and Queensland producers.

The figure below shows the sources of domestic gas supply for the southern states in 2017 / 18. (excluding supply to the Queensland LNG export projects) and highlights the importance of Victorian gas supply (shown in dark blue) in satisfying market demand in the south eastern states.

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Figure 2. Demand on a state by state basis. Source: AER\(^1\), AEMO

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Figure 3. Supply for domestic gas for southern states Victoria, New South Wales, South Australia and

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\(^1\) Australian Energy Regulator
Australia’s east coast gas supply

Gas production in eastern Australia began over 50 years ago. The main production basins being the Gippsland, Otway and Bass Basins in offshore Victoria, the Surat–Bowen Basin in Queensland and the Cooper Basin in South Australia. Access to competitively priced gas, often a by-product of oil production, resulted in development of significant residential, commercial and industrial demand, using gas as a fuel source or feedstock.

The following figure from the Australian Energy Regulator shows their latest gas reserves estimates for the east coast of Australia and Northern Territory.

Figure 4. AER overview of 2P (proven plus probable) gas reserves by basin. Source: AER state of energy market report 2018

Gippsland/Otway/Bass basin
Following the depletion of reserves offshore in Victoria and the development of coal seam gas reserves in Queensland, the Gippsland Basin now only accounts for around 5% of eastern Australian reserves with an estimated 2272PJ 2P reserves or just under 2Tcf. A joint venture between ExxonMobil and BHP controls 80% of reserves in the basin. The principal producers in the smaller Otway Basin and Bass Basin are Beach Energy (72%), Mitsui (15%) and Cooper Energy (11%).

According to ExxonMobil, one of the Gippsland Basin’s large legacy fields has depleted earlier than expected, with another two fields expected to be depleted in the early 2020s. In the longer term, the consultancy Energy Quest predicts gas production from Victoria’s offshore fields will fall by 57% in 2022 from the levels seen in 2017. It is not yet clear what the remaining smaller and new gas fields can deliver but this tightening supply situation is making it increasingly challenging for buyers of gas, like AGL, to secure the gas required to keep customers well supplied.

Exploration wells in the Gippsland basin are proving highly risky, as illustrated by the recent drilling of the Baldfish well to test the Dory prospect, initially thought to have the potential to be one of the largest untapped gas resources in Victoria. After several months and $120 million in drilling expenditure, ExxonMobil announced in November 2018 that no commercial levels of hydrocarbons had been encountered.

Cooper Basin

The Cooper Basin in central Australia has around 1000 PJ of 2P reserves and almost 6000 PJ of contingent resources. A joint venture, led by Santos (66 per cent) with partner Beach Petroleum (34%), controls most of the reserves in the basin, which account for 2% of eastern Australia’s 2P reserves. Santos entered an agreement in 2010 to supply one of the Queensland LNG projects with 750 PJ of gas over 15 years, which has accelerated the depletion of the basin’s conventional reserves.

Surat-Bowen Basin

The Surat-Bowen Basin in Queensland is the largest basin in eastern Australia, it accounts for nearly 90% of all eastern Australian gas reserves. Most of the gas in the basin is exported by the LNG projects in Queensland. The basin also supplies most of Queensland’s domestic gas needs. Participants in Queensland’s LNG projects control most of the reserves in the basin, which are mostly Coal Seam Gas. Shell (29%) is the largest equity holder, followed by Origin (13%), ConocoPhillips (12%), PetroChina (10%), Sinopec (8%), CNOOC (6%), Santos (5%), Petronas (4%) and Total (4%).

Amadeus/Bonaparte basin

The eastern gas market has until very recently been isolated from the Northern Territory. This, however, changed in late 2018 when the Jemena owned pipeline was commissioned, known as the Northern Gas Pipeline, the pipeline now links the Northern Territory to Queensland. The onshore Amadeus Basin in Northern Territory historically met all domestic gas demand in Northern Territory but has been in decline for some time. Gas developed from fields in the offshore Bonaparte Basin and Browse Basin will support LNG export plants in Darwin. The Bonaparte basin is currently estimated to have over 800 PJ of 2P reserves so it is possible that new gas finds onshore in Northern Territory might find its way to the east coast gas market. These molecules will again be considered for exports by LNG projects in Darwin and Queensland and are constrained by the 12inch, 90 TJ/d
capacity of the Northern Gas Pipeline.

In summary, declines in reserves in the Gippsland and Otway Basins in the south in Victoria, suggest that the volume of gas available will soon be below what is required for the southern states. Without new local supply sources, gas will have to come from Queensland reserves and/or those volumes currently directed towards Queensland’s large LNG export projects.

**Australia’s east coast gas demand**

Domestic demand for gas in eastern Australia derives from three sources—Commercial and Industrial gas users (around 41% of domestic demand), gas powered generators (29%), and residential customers (29%). With the launch of three separate LNG export projects in 2015, international customers became not only a new source of demand competing to buy eastern Australian gas⁹, but also by far the largest source of demand. In round figures, the demand for gas from the LNG projects is roughly double the rest of the east coast market combined.

With the rapid penetration of electricity generation from renewables, the requirements for gas for use in power generation remains the most volatile demand segment. Demand from this sector is expected to decline in the near term due to growth of renewable energy but then recover as coal-fired generation capacity is retired. Gas demand for commercial and residential customers remains relatively flat. The future demand for gas by industrial users is expected to decline with customers citing high prices as a significant risk to commercial viability of their business¹⁰.

The forward gas demand (mid case) forecast by the Australian Energy Market Operator (AEMO) remains relatively flat overall. The most significant demand increase for gas comes from the Queensland LNG export projects. Queensland’s three LNG projects were originally anticipated to source their gas requirements from their own reserves in the Surat-Bowen Basin. However, development of upstream reserves by the GLNG project has proven lower than expected, resulting in the sourcing of volumes from other producers. Energy Quest has estimated that GLNG relied on third parties for around 30% of its LNG plant feedstock in the June quarter of 2018¹¹.

**Australia’s east coast supply and demand outlook**

AEMO’s estimates of supply and demand¹² of gas on the east coast of Australia (shown in the figure below) highlights a significant gap beyond 2020 and a very high reliance on the addition of contingent resources. Closing this gap relies heavily on finding and commercialising additional reserves at a time of onshore drilling moratoriums. The Victorian offshore basins seem increasingly challenged to identify new resources and the distance and high mobilisation costs to bring drilling rigs to the region provides additional challenges.

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⁹ AER, State of Energy Markets 2018
¹⁰ ACCC, Gas inquiry 2017–2020—Interim report, July 2018
¹¹ EnergyQuest, *Energy Quarterly*, September 2018
¹² AEMO neutral demand profile assumed from June 2018 Gas Statement of Opportunity.
Australian east coast pipeline network constraints

The eastern states of Australia had typically seen a transmission pipeline linking a gas basin to supply the closest demand centre. Over the past 20 years, these pipelines have become interconnected and many have become bidirectional. Mostly recently, with the addition of the Northern Gas Pipeline, it is theoretically possible for the east coast to access gas from offshore basins to the north west of Australia.

The following figure highlights the main pipelines on the east coast of Australia.
With the projected decline in supply of domestic gas from the Gippsland & Otway Basins offshore Victoria, the southern states will need to look elsewhere to fulfill their gas needs and will naturally focus on the next nearest major source of supply; Queensland’s CSG resources. However, the only pipeline that connects Queensland to the southern states is the South West Queensland Pipeline.
Figure 7. Flows on the South West Queensland Pipeline. Positive number is flow from Queensland to southern states. Negative number is flow from southern states to Queensland. Source: AEMO Gas Bulletin Board

The South West Queensland Pipeline has maximum capacity of 384TJ/day, flowing from Queensland to southern states and, as Figure 7 illustrates, it is already close to being fully utilised during Australia’s winter months. An increased reliance on Queensland will likely result in a bottleneck to gas flows to the southern states unless the capacity of the South West Queensland Pipeline is expanded. It is worth noting that the distance from the Wallumbilla gas hub in Queensland to Melbourne is over 1,300 kilometres in a direct line and any new large diameter gas transmission pipeline would probably be double that distance, traversing three or four states.

Investment in transmission pipelines in Australia is expensive and requires long-term investment and throughput commitments to underpin a decision to invest capital. This type of investment will usually require long term transportation agreements over 10 – 20 years to underpin the scale of investment. As an example, the 12 inch, 622km Northern Gas Pipeline linking Tennant Creek in Northern Territory to Mount Isa in Queensland had a budget of $800million and took 5 years to develop, adding an additional 90TJ/day.

The market’s inability to offer long-term gas supply agreements for the domestic market compromises the economics underpinning investment in pipeline expansions. Without timely and adequate investment in pipeline infrastructure and willingness from government to support onshore exploration and the development of new pipeline assets, the ability to transport gas onshore to where it’s needed will be severely compromised.

**Australian east coast domestic gas pricing**

Prior to 2011, Australia’s east coast gas market was characterised by stable pricing and was isolated from international gas markets. Gas prices were considered low by international standards and were negotiated on a bilateral basis at a fixed price plus CPI. The pre-LNG era in eastern Australia is often viewed as a time of assured supply, low gas prices, flexible contractual terms and long term bi-lateral contracts. The development of the Queensland LNG industry has fundamentally transformed the east coast gas market. Gas producers have shortened contracting timeframes, often to 5 years or less, increased gas prices and reduced contractual flexibility.

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13 Consumer Price Index
for buyers. Going in to the next decade, many buyers are struggling to obtain offers for gas supply.

*Increase in east coast domestic gas price in recent years*

Since the commencement of the LNG exports from Queensland, the increased demand for gas has seen prices in the domestic market increase rapidly.

The overall averages of gas prices are 51 per cent higher in Q2 2018 than they were in Q2 2015 according to the Australian Competition and Consumer Commission (ACCC). There was a notable increase between Q4 2017 and Q1 2018, during which the average price charged to C&I gas users rose from A$7.58/GJ to A$9.25/GJ, a 22 per cent increase over two calendar quarters. The ACCC report shows that the prices paid by C&I gas users under recent gas sales agreements continued to rapidly rise, hitting A$9.65/GJ by Q2 2018.

When the market was supply constrained in 2016 and 2017, the domestic gas prices in Victoria increased to track the cost of the marginal supply from Queensland at LNG netback pricing to Melbourne. This can be seen in the figure below, which shows the actual Victoria market price tracking closely to a north Asia LNG netback price to Melbourne (assuming 12% Brent).

Figure 8. Victorian Market price vs LNG netback price. Source: AEMO and AGL analysis.

This example reflects a short-term tightening of the market that was otherwise well supplied. Once the depletion of traditional gas suppliers to southern states post 2020 leads to a long-term structural shortage, market prices will again ascend to that of the marginal supply cost of gas to meet demand, which without LNG imports would be gas diverted from Queensland LNG export projects into the domestic pipeline gas market. Critical to this assumption is sufficient reserves in Queensland to meet existing LNG contractual obligations and to divert gas to domestic markets. If this proves insufficient, then gas from on-shore Northern Territory will need to be piped down, setting an even higher market price unless inelastic demand is destroyed.

*Economics of imported gas vs piped gas*

The figure below is an example to help illustrate the economics of the two main supply sources of gas to southern states to fill the void left by Gippsland/Otway reserves depletion; being Queensland LNG diversion and LNG imports. The figures are taken from worked examples appearing on the Australian Competition and Consumer Commission (ACCC) website and haulage charges are from AEMO.

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14 ACCC Gas Inquiry 2017-2020. Interim Report, December 2018
Figure 9. Pipeline haulage charge from Queensland Wallumbilla. Source: AEMO haulage charges and ACCC LNG netback price series.

For illustration purposes, an US$8/MMBtu LNG marker price in north Asia and freight of US$0.50 is assumed. Using a 0.75 exchange rate and 1.055 conversion rate for MMBtu to GJ, this translates to a A$9.48/GJ FOB Gladstone LNG price.

Figure 10. LNG FOB Gladstone calculation. Source: ACCC LNG netback price series.
If excess gas were sold by LNG producers into the domestic market rather than exported as LNG, then LNG producers will save the costs associated with gas consumed as fuel during liquefaction process, as well as LNG plant operating expenditure. If we take A$9.48/GJ FOB Gladstone and subtract LNG plant fuel, efficiency and operating expense and account for the marginal costs of transportation to Wallumbilla, the ACCC data estimates an LNG netback price at Wallumbilla of A$8.91/GJ based on US$8/MMBtu LNG marker price in north Asia.

![Figure 11. Calculation of LNG netback price at Wallumbilla. Source: ACCC LNG netback price series.](image)

From a Queensland gas producer’s perspective, selling marginal uncontracted volumes to the domestic market will help to save around an estimated A$1.23/GJ\textsuperscript{15} in avoided costs; being the avoided domestic costs and freight to Asia. For a buyer in Melbourne to purchase this gas, the cost of reserving haulage capacity from Wallumbilla to Melbourne, as estimated by the Australian Energy Market Operator (AEMO), is around $2.98/GJ, yielding a delivered cost in Melbourne of A$11.98/GJ if that capacity is fully utilised.

In this example, from a southern state gas buyer’s perspective, if the cost of LNG plus regasification and haulage from an LNG import project located at Crib Point near Melbourne is less than A$11.98/GJ, then gas from Crib Point will be delivered to market at a lower cost than Queensland. Using the US$8/MMBtu prices for Delivered Ex Ship (DES) LNG, LNG could be delivered to Crib Point for A$10.11, leaving A$1.78/GJ to cover storage and regasification costs. Furthermore, an LNG import facility can be ramped up as required without the bottleneck constraints of a domestic gas transmission network allowing it the flexibility to offer in to the spot market on a daily basis.

![LNG import to Crib Point](image)

![Diversion of QLD gas to Melbourne](image)

Figure 12. Imported LNG prices vs Piped LNG price. Source: AEMO haulage charges and ACCC LNG netback price series.

The economics illustrated above is an oversimplification of what happens in reality. The pipeline capacity charge calculation assumes the capacity is fully utilised, which may be the case in winter, but is unlikely in summer. Furthermore, the “market” LNG price considered by Queensland gas producers and those of LNG importer is rarely the same. For example, the ACCC has commenced reporting of an LNG netback price at the Wallumbilla hub utilising JKM and a Gladstone to Tokyo Bay freight assessment, whereas sellers of LNG from Queensland may be selling to other destinations and on pricing based on a 3-month average of Brent or Japan Crude Cocktail (JCC).

AGL intends to acquire a tranche of LNG based on medium term LNG supply contracts that removes exposure to spot pricing and provides the ability to lock in a forward curve through oil price hedging. Thus, it is unlikely that an import project and buyer of gas on LNG netback prices will both start at “US$8/MMBtu” as assumed in the Figure 9 example.

However, the point remains that the cost of piping gas all the way from Queensland to Melbourne is significant and given the constraints in the South West Queensland Pipeline, there may not be additional transmission capacity without expansion of that pipeline. Any expansion of the South West Queensland Pipeline will be capital intensive and time consuming and result in a much higher gas transmission tariff from Queensland to the southern states. It is also expected that Queensland LNG projects will continue to purchase significant amounts of gas from the domestic market, especially during shoulder seasons, in order to optimise and extend the life of their own reserves.

Therefore, in a market where supply is soon expected to fall short of demand, having an alternative gas supply point, such as the gas import jetty project at Crib Point proposed by AGL, will help alleviate the supply shortage and puts downward pressure on the price otherwise payable by consumers in the southern states. An LNG import facility also provides access to the global market and does not rely on the development of contingent or yet to be discovered resources, it will also remove uncertainty and ensure there is security of supply of gas to meet the needs of AGL’s 1.4 million gas customers.

AGL’S GAS IMPORT JETTY PROJECT

During the feasibility study stage of the project, AGL evaluated seven sites as potential locations for the import project, including Crib Point in Victoria, Port Adelaide in South Australia and Port Kembla in New South Wales as well as the Port of Newcastle, Botany, Corio, Port of Melbourne and Bell Bay. Most of the sites were ruled out due to factors including the lack of suitable berths, the need for dredging and its associated environmental issues and limitations on the gas transmission pipeline networks to deliver gas to the key gas markets. In the end, the Crib Point jetty in Western Port, 65km south of Melbourne (Victoria) on the Mornington Peninsula, was identified as the preferred site for AGL’s gas import jetty project.

The figure below shows the location of Crib Point and Western Port.

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Crib Point is well placed to serve Victoria, Australia’s largest gas market, and offers:

- an existing deep-water industrial port in a sheltered bay;
- an existing under-utilised jetty of suitable size to be remediated to accommodate the FSRU at a dedicated berth and receive a double berthed LNG Ship up to 295m length overall alongside; and
- connection to the existing high-pressure gas transmission grid via a new pipeline lateral of approximately 57km.

AGL announced the site selection decision in August 2017. In June 2018, AGL and APA, Australia’s largest gas transmission network owner and operator, entered into a Development Agreement, which contracted APA to design the pipeline, seek land access, arrange all required regulatory approvals and, if approved, to build, own and operate the Crib Point Pakenham Pipeline, which will connect Crib Point to the gas transmission network in Victoria and the east coast of Australia. At the same time, AGL and PoHDA – the Port of Hastings Development Authority – executed Agreements to allow for the remediation of the Crib Point jetty to prepare for AGL’s exclusive occupation of Berth 2, for the continuous mooring of a floating storage and regasification unit.

Both onshore and offshore regasification and storage technologies were considered during the project screening phase. A land-based storage facility would consist of a regasification plant and installation of large storage tank infrastructure and would take 3.5 to 4 years to construct, requiring a large onshore footprint that would need to be decommissioned and rehabilitated upon project completion. In comparison, the FSRU being an operating ship, can be relocated elsewhere on conclusion of the project or as required. Being moored at the end of a jetty also provides additional separation from nearby onshore infrastructure and communities. This led to the selection of the FSRU technology for AGL’s gas import jetty project.

Additionally, the FSRU option provides the ability to implement the project over a shorter timeline to address impending shortages and the ability to spread costs over the life of the project as an operating cost, rather than upfront capital commitments and these advantages were seen as beneficial to the project’s viability.

LNG delivered to the project will be pressurised and vaporised onboard the FSRU to deliver high pressure gas vapour to the jetty via rigid marine loading arms. Gas from the FSRU will be received by a flowline positioned on
the jetty connecting with the pipeline to the Victorian gas network.

In December 2018, AGL announced the signing of a long-term time charter party agreement for supply of an FSRU from Hoegh LNG, an industry leader in the operation of modern, floating LNG import terminals with more than 40 years LNG shipping industry experience.

The AGL gas import jetty project will provide Victoria with a new virtual pipeline to natural gas from existing and new LNG projects in Australia and around the world, with the potential to supply up to 160 petajoules (PJ), or 2.8 million tonnes of natural gas per annum, equating to around 75 per cent of Victoria’s annual gas consumption based on 2017 consumption figures. In addition, the location of the facility allows the injection of gas into the existing east coast gas transmission network to provide supply to South Australia, New South Wales and Tasmania, where required.

Project Key Challenges and Solutions

The Crib Point Jetty, located within the Port of Hastings in Western Port, Victoria was originally constructed in the 1960’s to serve a BP refinery at the site. The Port of Hastings has been a commercial port for more than 50 years, and although the refinery closed and has been removed, the Port of Hastings continues to serve international shipping operations, including the import and export of products such as crude oil, liquefied petroleum gas and steel, with between 100 to 150 vessels using the Port of Hastings each year.

Like any major infrastructure project, there are challenges to overcome to ensure its successful and safe delivery. Some of the key challenges for this project include being in an environmentally sensitive area and the need to minimize the project environmental footprint. Construction of the new pipeline lateral of approximately 56km requires access to a mixture of rural residential, road corridors, rail corridors, industrial land and conservation reserves.

Community Engagement

The other key challenge area is getting the local community to accept the LNG import facility in their backyard. It is a challenge we haven’t underestimated. Nobody wants new infrastructure in their neighbourhood, no matter how badly its needed.

We have learnt from our experience in coal seam gas development, that simply getting your supporters on side and trying to convince an apathetic general public of the benefits of a project isn’t enough.

Working with those most concerned -- and therefore strongly opposed to the project -- has been our key focus. To date we have held around 30 open public meetings with local community groups --sometimes as large as 200 people -- to acknowledge and respond to their concerns.

We have tried to move beyond simple transparency, to a more straightforward honesty and frankness, in which all our draft environmental and technical assessments -- even when we don’t yet have all the answers and when we don’t like the findings -- have been provided to the community and environment groups. They have had access to our draft reports well before they have been provided to regulators and the government.

The aim of our engagement is not to try and change the community’s minds with the facts, but to build trust by showing we are willing to be accountable for the inherent risks a FRSU and pipeline will bring to a community. Ultimately, by working with them to solve the problems together, we want them to win under conditions the project can live with.

It isn’t an easy task, both internally and externally, and this will remain an ongoing challenge.
Environmental approvals

In October 2018, the Minister for Planning of the state of Victoria issued a decision determining that an Environmental Effect Statement (EES) was required for the project. An EES is an assessment statement to ensure that all relevant environmental uncertainties are rigorously investigated as part of an integrated assessment process prior to any statutory approval decisions. AGL and its pipeline partner APA are working through the EES process with regulators and community are part of this overall approvals and licensing process.

CONCLUSION

The dynamics of the Australian domestic market have changed. Faced with competition for domestic gas reserves from LNG export projects and accelerated depletion of traditional gas supply sources, the east coast domestic gas market is predicted to experience gas shortages beyond 2020-21.

The vast distance of the Australian landscape means piping gas from its origin to demand centres is a capital intensive and costly process, this coupled with competition from overseas consumers for Australia’s east coast gas reserves generates the business case for an LNG import project nearest to its highest gas demand centre, Victoria. AGL’s gas import jetty project at Crib Point, Western Port, Victoria will establish an alternative source of gas for the east coast market and provide much needed flexibility and security of supply of gas molecules in future years. In the next decade Australia will become both an exporter of LNG and an importer to meet the needs of the Australian market.