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GAS AND OIL PROSPECTS

The insertion of Australia into international markets

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Executive summary

In the coming decades natural gas may take a lead role in providing energy to the world while mitigating climate impacts. Our optimistic view is based on the advantages of gas relative to other fossil fuels, including its abundance, wide geographical distribution and environmental impact – natural gas emits fewer emissions than coal and oil when burned. In addition, there have been substantial cost reductions in liquefied natural gas (LNG) production, transport and receiving technologies.

This report develops a reference point for stakeholders interested in an outlook for development of gas resources in Australia, with a focus on prospects for the proliferation of LNG trade.

As the natural gas sector becomes increasingly globalised Australia's position cannot be considered in isolation. Having invested around $200 billion in LNG over the past decade, the industry has survived its most critical stage and should now concentrate on maintaining its position beyond 2020, when significant LNG capacity is likely to emerge from other regions. Australian suppliers, expected to be higher up the cost curve than some key competing countries, will have to consider imaginative ways of being innovative and managing risk.

The recent propagation of flexible gas pricing will open the door to new opportunities, and so will new technologies like floating liquefaction and regasification terminals. Transferrable capital resources and expertise from the mining industry, couple with government and corporate management experience, and high energy and gas demand expectations are all factors in favour of the industry. Climate policies could play a facilitating role too; a sufficient tax on carbon, for instance, increases the relative cost of coal while promoting investment in gas development. On the other hand, there are looming challenges: the possibility of lacklustre gas demand growth in Asia, probable expansion of competing LNG supply from the US, Russia and Qatar, competition from coal and renewables, domestic supply pricing issues in Queensland and the Australian Government's passiveness in some areas.

On balance, we find favourable prospects for Australia in the long-term energy landscape – given the country's prominence as a gas and LNG supplier and our view of sufficient global gas demand to absorb future supply from diverse sources – but we emphasise that both the gas industry and governments should be ready to innovate and adapt to rapidly-changing market conditions.

Key findings

Global energy mix considerations

- Renewable energy fails to provide base load supply in electricity markets, and it is therefore unlikely to cover a substantial market share in electricity markets worldwide.
- Coal-for-gas substitution is arguably the most practical, cost-effective way of achieving environmental targets.
- China's Action Plan for an Air Pollution Control pilot program shows the potential of coal-for-gas substitution, with the main practical limitation being a lack of gas infrastructure.
- Empirical academic literature identifying causal links between GDP and energy consumption suggest that environmental policies aimed at reducing energy consumption may be harmful.
- Looking forward, it will be of interest to observe the evolution of causal links, recommendations and policy actions in Asian economies.

Natural gas global patterns and flows

- The level of natural gas proven reserves is essentially a dynamic measure that depends on the level of investment, technology and other economic conditions.
- New technologies allowing for extraction of shale and other unconventional gas and oil resources have acted as a game changer, shifting geo-economic power and re-defining markets.
- Physical interconnections between regions that produce and consume natural gas are heavily constrained, leading to regionalised markets.
- Natural gas consumption growth in Asia Pacific, averaging 8.89% p.a. in 1970-2015, has been the main driver of global demand growth.
- China has been the main contributor to natural demand growth in Asia Pacific. Imports are diversified with Australia supplying 13% in the form of LNG.
- Roughly 80% of natural gas trade in Asia Pacific is in the form of LNG.

Natural gas markets: Regionalisation, pricing and LNG Trade

- The world's imperfectly-linked regional natural gas markets lead to distinctive pricing mechanisms in North America, Europe and Asia Pacific.
- Policies addressing third-access-party have been instrumental in the development of a competitive natural gas market in the US, but it took decades to achieve this status.
- With current LNG terminals under way, the US is set to become a major destination-flexible supplier of FOB LNG.
- In Asia Pacific, a typical long-term supply contract would tie the natural gas price to oil prices.
- Australian LNG suppliers could seek strategies to diversify risks by offering both long-term oil-indexed and short-term gas-on-gas priced
- The Australian LNG industry has passed its most critical point yet, and will become the largest LNG exporter by 2020. The main issue is how brownfield investment can be accommodated beyond 2020.

Key findings (continued)

- Australian LNG stakeholders should keep an eye on the rest of the world. Supply from Qatar, Russia and Africa has been so far contained, but could unleash in the future. South America might be a possible LNG destination in the short run, but has plenty of own long-run supply potential. Canada LNG exporting potential has so far not been realised.

International trends in oil markets

- Oil demand and supply are highly inelastic, which means that small changes to production and consumption lead to large price changes, causing volatility.
- Future oil prices are difficult to predict. The current state of affairs and market conditions suggest that major oil prices should remain in the US$ 60-70/barrel level.
- However, history has demonstrated that at least one major supply disruption occurs in a decade.
- Futures contracts are a very important instrument for hedging price risk variation in oil markets, and might play an important role in liquid gas-on-gas trading hubs in Asia, should they develop.

Recent technological developments

- Fracking safety is a sensitive topic, and it would be in the interest of everyone in Australia to conduct an independent assessment and educational campaign.
- The US shale revolution is the result of years of research and government support.
- Australia has the highest per capita endowment of technically recoverable shale gas in the world.
- A comparative advantage of Australia for technological development and risk diversification is that it possesses all main types of natural gas.
- Strong regulations in NSW have put a freeze on new CBM developments.
- Cargo ships with re-gasification capacity have the potential to be a 'game changer' for the Australian LNG industry, so we recommend that companies and policy makers look seriously into it.

Australia's position

- Long-run demand prospects for both natural gas and LNG in Asia look strong.

Policy implications

- For policy makers, there is a trade-off between short-run tax benefits and long-run interests. Credibility through long-term commitment is the most important of the two.
- If key international competitors continue to receive substantial R&D support from their governments, Australian policy makers will have to decide whether to match it or let the industry fall in the long run.
- The Australian government has always found ways of bringing innovative solutions. Now, it is faced with a unique opportunity for establishing international leadership in the natural gas sector through first-mover advantages.

- Some gas-related state government that involve research, regulation and administration would be better conducted at Federal level or with increased cross-state collaboration. Further natural gas TPE regulation will be needed, and the regulation of pipeline schemes should be simplified.
- It would be desirable to have an agency to compile and disseminate energy data, beyond electricity markets, as the energy industry has grown and become more diverse.
- It is our position that the reservation policies simply do not work. A reservation policy would also be incompatible with carbon pricing.

Can we expect a second resources boom?

- All in all, the short answer is yes.
- The Australian gas industry has the potential to unleash vast wealth to the Australian economy.
- However, there are external and internal risks that may affect this outcome.

Introduction

This report has been prepared in a unique era for Australia. Global energy markets, in particular liquefied natural gas (LNG), have undergone radical demand and supply changes in the last decade. New technologies have opened up large-scale development of unconventional gas and oil resources that were previously considered economically inviable. This 'game changer' has caused substantial market re-structuring and geopolitical transformation. Added to this, demand in Asia has expanded at an unprecedented pace and created new investment opportunities for energy producers. These situations, coupled with increasing pressure on policy makers to achieve carbon dioxide emission reduction targets, has had deep impacts too. Australia is now in a unique position, where various stakeholders are faced with opportunities, threats, and high uncertainty. However, they have also encouraged a rapid expansion of Australia's LNG exports.

What has attracted the attention of many Australian stakeholders is not only the scale of investment projects but also the relatively short period of time from which they are announced to when they become operational, even with frequent delays. Generally speaking, there has been limited information on how Australia is inserting itself in international markets. Addressing these issues, Australian government authorities have prepared or commissioned a number of reports, including publications by the Australian Energy Market Operator (AEMO) (2016*a*, 2016*b*), Oakley Greenwood (2016), Department of Industry, Innovation and Science (DIIS) (2016), Lowe (2013), Bureau of Resources and Energy Economics (BREE) (2014), Australian Energy Regulator (AER) (2015), Core Energy Group (2013), Intelligent Energy Systems (IES) (2013), and Geoscience Australia and BREE (2013). These reports generally focus on domestic issues, largely electricity markets, and lack international perspective. On the other hand, numerous international industry reports covering international energy markets which are not designed from an Australian perspective exist, e.g. International Energy Agency (IEA) (2016), Energy Information Administration (EIA) (2016), BP (2016*a*, 2016*b*), and International Gas Union (IGU) (2015, 2016).

Finally, reports by the Australian Petroleum Production and Exploration Association (APPEA) analyse market structures and policy trends in attempts to understand the environment in which LNG investors make decisions. Our report fills gaps between the aforementioned sources. It analyses international market structures and policy trends to understand the environment in which LNG investors make decisions. Issues involving domestic electricity generation and pricing issues are kept to a minimum, some of which involve natural gas, due to the vast literature already available. A feature that makes this report distinctive is the focus on LNG prospects for Australia.

The present BCEC report is intended to serve various stakeholders, including: business analysts who are interested in overviews of key trends and developments that underpin the profitability and risk of LNG investment; policy makers who wish to develop an understanding of key issues in the business and identify needs for policy change; academics and members of the public who want to deepen their knowledge on the topic; and industry executives responsible for investment decisions in firms that produce and transport natural gas.

Important

questions

Important questions

This chapter focuses on how Australia fits in the big energy picture by identifying relevant questions to be investigated in the rest of the report. We argue that although a major and significant energy-tradable commodity for Australia is natural gas, some events arising from the international oil market as well as energy policies in general need to be taken into account to fully understand Australia's prospects. Thus, we focus on consumption patterns in Asia-Pacific that are driving Australia's natural gas exports, and how external forces –such as technology, supply from other regions and policy – come into play.

The global trends question

What are the trends in consumption and production of natural gas in the Asia Pacific region and the world?

Australia's position cannot be understood in isolation, considering natural gas, oil and coal markets are increasingly integrated regionally and globally. To put our analysis into perspective, the report examines the following data trends in detail:

Energy mix. The last two decades have been characterised by steep upwards trends in world primary energy consumption and trade. Much of this growth has originated in Asia Pacific, but so far, economic growth in that region has mostly been fuelled by coal and to a lesser extent oil. Though, natural gas offers several advantages over oil and coal, and thus, going forward the importance of natural gas is expected to increase substantially. Natural gas produces less carbon dioxide emissions than oil and coal, making it an important instrument to meet policy emissions targets. Following the United Nations' COP21 meeting in December 2015, held in Paris, several oil and gas companies have signalled an aim of shifting their portfolios towards natural gas. Still, this policy option has been underutilised, mainly due to natural gas infrastructure constraints and underdeveloped markets that we will analyse later in this report.

Global consumption, production and trade patterns. To understand the interactions of energy flows between regions in the world, we present a comprehensive review of selected consumption and production profiles. We argue that it is important to consider not only the energy mixes of each market, but also the dynamics, i.e. growth rates for consumption and production. For natural gas markets, we compare reserves, demand and supply estimates, as well as pipeline and LNG trade. The focus is on the Asia Pacific market where Australian LNG flows.

Demand prospects. From the demand perspective, some producing nations, including Australia, are concerned that perhaps gas demand in Asia will not be sufficiently large to accommodate all possible gas supply sources. The past decade saw heavy investment in LNG projects – around $200 billion in Australia alone. When the volumes come on stream in the coming years, they are expected to contribute to an already substantial LNG supply glut in Asia. Despite current circumstances, producing companies expect that the overhang will be alleviated towards the end of the decade as demand picks up and supply growth slows due to ongoing cancellations and deferrals of projects in the low price environment.

LNG pricing. New thinking may also be needed in seller-buyer relations, including the introduction of flexible terms and contracts. Natural gas pricing in Asia has historically been a buyers' market in which prices have been linked to crude oil in long-term contracts. From this perspective, it is important to understand trends in oil prices in order to assess gas prospects. However, the Asian market is now changing and transitioning very slowly towards a spot price market. So, trends in LNG pricing and regional market developments will be covered.

The unconventional gas and oil question

How have technological advancements in the development of unconventional gas and oil resources (such as that from tight and shale formations) affected global trade patterns and the economic development of these resources in Australia?

This question refers to the supply side of natural gas, and oil. The 'shale revolution' – resulting from technological progress that has made vast dormant gas and oil resources economically exploitable.. It started with fast-rising production of unconventional gas in the US around ten years ago, and unconventional oil followed in its footsteps soon after.

The availability and development of unconventional gas and oil caused deep changes in market structures, and for that reason the shale revolution is often referred to as a 'game changer'. At present these market changes have not yet consolidated. That is, we have not yet achieved a long-run equilibrium in which market structures are predictable and stable. So, significant changes in natural gas, LNG and oil production, consumption and trade patterns should be expected in the next five-to-ten years. This report assesses plausible evolution of these patterns while focusing on how Australia could reap the benefits of being an LNG supplier with a first-mover advantage.

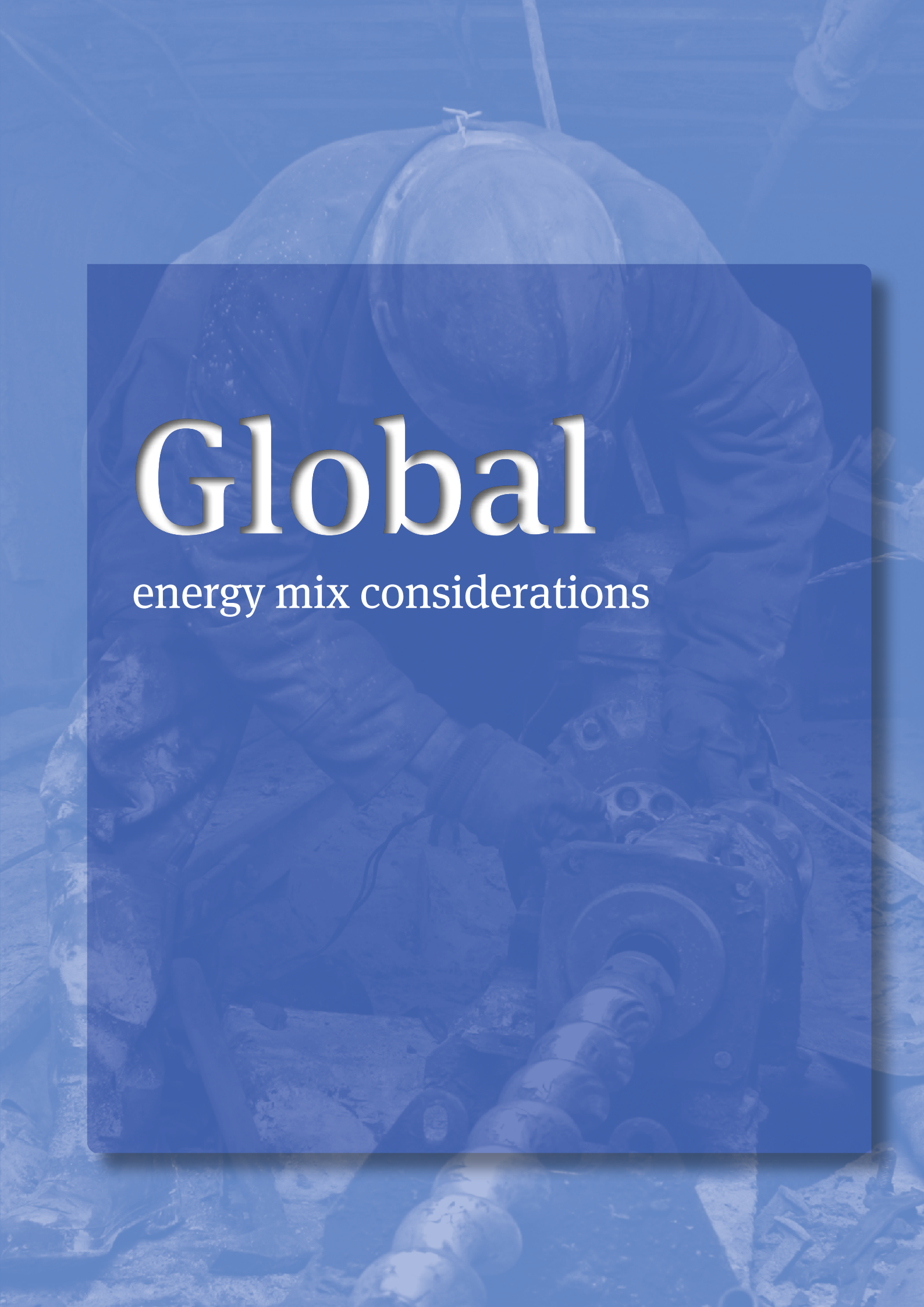
Recoverable unconventional gas resources are widely spread. Australia is estimated to account for about 6 per cent of the global shale gas total. Some experts believe Australia is likely to emerge as the most prolific shale-producing nation outside the US due to the similarities in above-ground (e.g. economic, policy, regulatory) factors between the two countries. Australia has well-established relations in Japan, South Korea and China, know-how, and a business environment that has facilitated substantial investment. The additional resources that could emerge would further enhance Australia's ability to provide regular alternative sources of gas to the Asia region and for domestic consumption. Australia's largest shale gas resource is in the remote Canning Basin of Western Australia. Despite being far from the domestic demand centres further down state, the Basin is relatively close to existing and nearly completed LNG facilities in the northwest. As such, the abundant gas resource could potentially feed into those LNG projects, particularly the ones in need of feedstock to match capacity. Efforts to develop shale gas in the Perth Basin, ideal for domestic use, are also under way.

The Australian LNG prospects question

What is the outlook for LNG development, considering the two questions above?

Despite the optimistic long-term outlook for natural gas consumption in Asia, Australian LNG producers are striving to bring project costs down. In the current setting of abundant supplies and low gas prices, improved productivity is seen as vital to make gas competitive against coal and to give Australia an advantage over other gas suppliers. Options include better early-stage planning across the supply chain, standardisation of equipment, reducing and simplifying construction activity, and the introduction of flexible technologies like floating LNG. The latter is gaining speed – being simpler and less costly than the recent mega LNG supply projects, where delays and cost blowouts became common. On the consumption side, floating import infrastructure is also being considered around the world. These floating vessels will enable less developed countries to increase their natural gas usage.

To shed more light on the prospects for Australian LNG, the findings in this report leads to identification of strengths, weaknesses, opportunities and threats for Australia's LNG exports (provided in the Discussion and Conclusion section).



Global

energy mix considerations

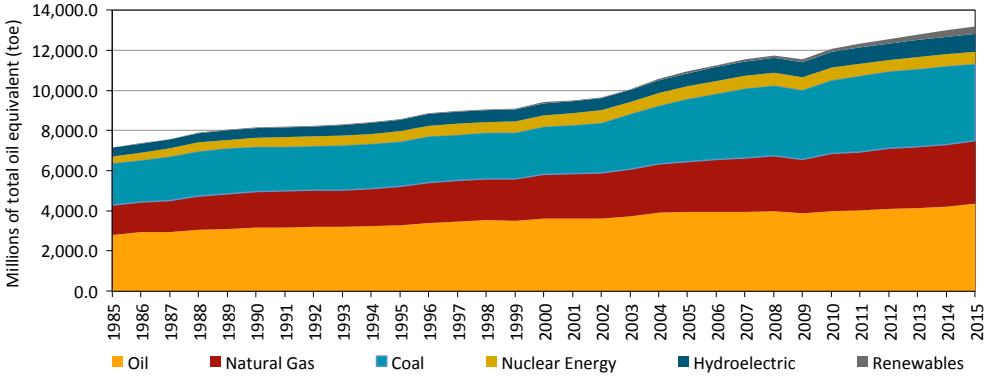
Global energy mix considerations

This chapter offers important insights into the global energy mix and environmental policies. It is put forward that natural gas *is* an environmentally-friendly energy source relative to the other energy supply sources that are currently used. It is demonstrated that there is enormous potential for substitution of coal by natural gas in power generation and the industry sector. A fuel substitution policy currently being implemented in China, the heaviest coal consumer in the world, demonstrates the potential of our proposition. Last, but not least, we examine dynamic links between energy consumption and income, and the implications for environmental policy.

The energy mix in 2015 at a glance: A helicopter tour

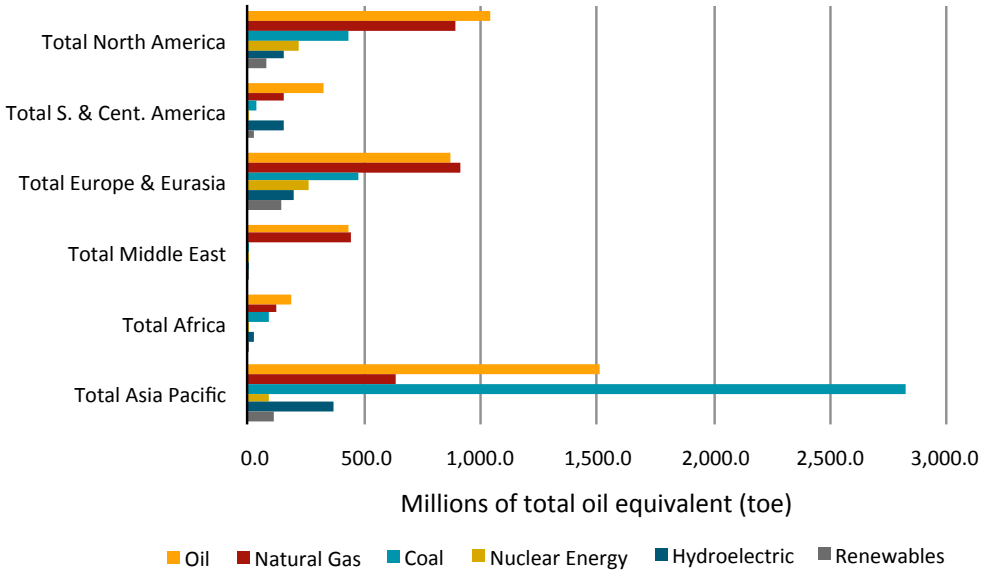
The first question we want to investigate is how natural gas fits into the world's energy mix. To approach it, we use the latest available aggregate energy statistics, which offer data up to 2015. In Figures 1 and 2, we display levels of primary energy consumption, measured in million tonnes of oil equivalent (the most widely used unit to compare primary energy aggregates). The data is segregated by region, and by fuel or supply technology. Globally, oil remains the leading source with 32.9 per cent of primary energy consumption; this share is interestingly about the same observed in 1950 (BP, 2016). Coal comes in second place, although this is not a trend commonly shared across all regions in the world (Figure 2). Coal consumption is disproportionally high in Asia Pacific (as seen in Figure 2) despite being generally in decline in OECD countries. Natural gas and renewable/hydroelectric energy have been the fastest growing energy types in the period considered in Figure 1, with the latter having a relatively small share.

Figure 1 Regional disaggregation of global primary energy consumption, in million toe, 1985 to 2015



Source: Authors' calculation from International Energy Agency data.

Figure 2 Composition of global primary energy consumption, in million toe, 2015



Source: Authors' calculation from International Energy Agency data.

Naturally, it is instructive to know which sectors consumed the energy produced in 2015. Because this is just a quick overview we will present selected facts, but full details can be found in EIA (2016) or BP (2016). The data reported above is classified in four categories: transportation, power, industry and other sectors. In the transportation sector, over 94 per cent of the world's energy consumption was obtained from oil, with natural gas and renewable energy accounting for 2.1 per cent and 3 per cent, respectively. With the advent of electric and hybrid cars, oil would be expected to slowly lose market share in the coming decades. Gas-powered motor vehicles have gained penetration in South America and Eastern Europe, but their popularity has not grown significantly. Where natural gas might have more potential for growth is in cargo shipping, as LNG fuel provides a cleaner alternative to fuel oil. In the power sector the contributions are as follows: oil 3.8 per cent, gas 21.5 per cent, coal 41.3 per cent, nuclear 10.7 per cent, hydroelectricity 16.2 per cent and renewables 6.5 per cent.

Renewable energy fails to provide base load supply in electricity markets, and it is therefore unlikely to cover a substantial market share in electricity markets worldwide.

In our electricity generation, most markets are, to a higher or lesser degree, exposed to pressure from carbon dioxide emissions targets, which have moderated the intensity in which coal is used and thus favour gas and renewables. Renewable energy has been growing at a rapid rate, thanks to substantial subsidisation, but from a low base. A major challenge for renewable energy (with the exception of hydroelectric and geothermal power) is that it typically fails to provide base load power. For instance, solar and wind generation units produce electricity when the sun shines or the wind blows, which does not necessarily coincide with peak demand periods. This is a problem in systems where all electricity produced has to be consumed or disposed of at a cost (a phenomenon known as negative pricing). Electrical storage technologies are in an experimental stage and there is presently no cost-effective way of storing energy at large scale.

All in all, major energy think tanks predict high growth of renewable energy over the long-term, but shares that are very far from the 100 per cent renewable energy electricity markets desired by some policymakers. The US Energy Information Administration (2016) predicts a 16 per cent market share of renewable and hydro in total by 2040. Likewise, ExxonMobil (2016) and BP (2016a) predict market shares for renewables (including hydro technologies) at 15 per cent and 16 per cent by 2040 and 2035, respectively. The desire for new production of electricity by nuclear energy has declined as a result of the Fukushima events in Japan, which led to safety concerns and decisions to shut down plants elsewhere. Finally, we have the industry sector, of which the Asia Pacific region has a share of roughly 50 per cent. In this sector, energy production shares are approximately evenly distributed among oil (31.3%), gas (33%), and coal (35.6%), with coal heavily used in Asia, especially China.

Natural gas: The fuel of the future

This report focuses on factors that could improve Australian LNG exports, but so far it has not been fully explained why this may be a desirable outcome in the first place. The economic value added by the Australian gas sector generates through spill over effects (that reach sectors other than energy), with most Australians familiar with this from experience with the resource boom. The possible disadvantages, as put forward in public debates, are often obscure. Here, we address the popular belief that burning natural gas does not enhance environmental policy.

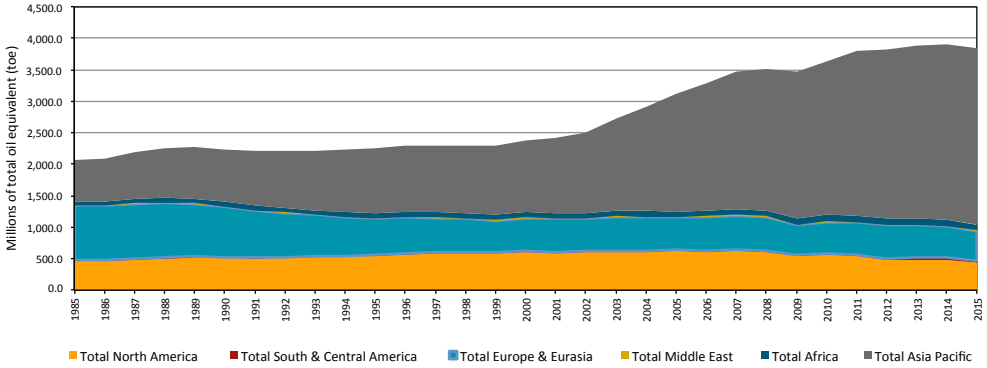
The big question in the present state of affairs is how to reduce coal consumption. To understand why, we explore Table 1 which shows the average amounts of fuels that are necessary to produce a unit of energy. It is clear from Table 1 that if coal and oil could be substituted by natural gas, the potential for reduction in carbon dioxide emissions from current levels would be very significant. Whereas natural gas is an imperfect substitute for oil in transportation, it is a very suitable long-term coal substitute for power generation and industries. The potential of natural gas for coal substitution is graphically quantified in Figure 3. We should recall that most of this coal in consumed in the power and industry sectors, and that China is the largest coal consumer.

Table 1 **Average fuel carbon emissions per million British thermal units (Btu)**

Fuel	Pounds of CO^2/Btu
Coal (anthracite)	228.6
Coal (bituminous)	205.7
Coal (lignite)	215.4
Coal (subbituminous)	214.3
Diesel fuel and heating oil	161.3
Gasoline	157.2
Propane	139.0
Natural gas	117.0

Source: Authors' calculation from US Energy Information Administration data.

Figure 3 Coal production, in million toe, by global region, 1985 to 2015



Source: Authors' calculation from International Energy Agency data.

Coal-for-gas substitution is arguably the most practical, cost-effective way of achieving environmental targets.

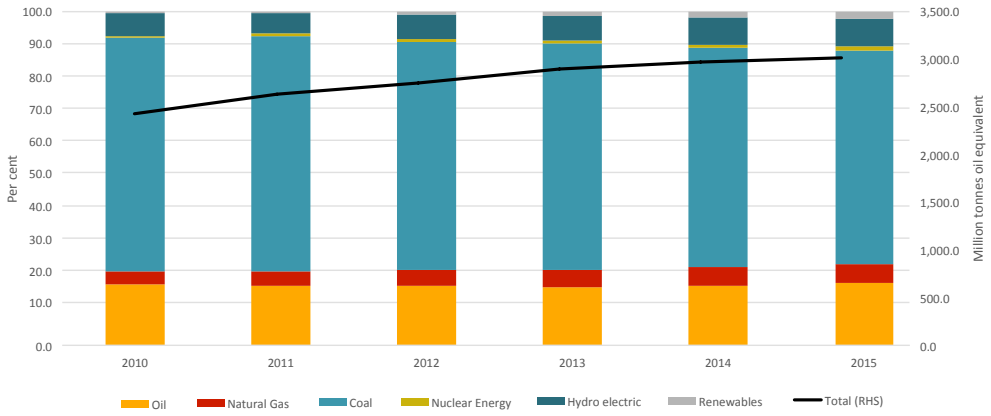
Of course, substituting coal for renewable energy would be optimal (in terms of reducing carbon emissions), however, such a scenario cannot be fully achieved in the foreseeable future. Renewable energy depends heavily on government support and active policies, and is inherently unstable as due to its intermittent nature. It is then the balance of coal that cannot be substituted by renewable energy that could potentially be replaced by natural gas. Both policies can be – and in fact are – enhanced with high taxes on carbon. It is worth noting that such measures are generally enough to cause coal-for-gas substitution, so simplicity is one of the attractive features of this policy.

Enhancing environmental policy with natural gas: China as a case study

It is not within the scope of this report to review environmental policy targets worldwide. The latter would be a very difficult task considering that countries constantly re-adapt their emissions targets based on both economic and political factors. This is especially true in the post-COP21 world, as countries started to adopt non-binding commitments to reduce carbon emissions. Each country ratifying the Paris Agreement in 2016 committed to setting a voluntary NDC (national determined contribution), with no set date commitments, and no enforcement mechanisms. China has been generally open to voluntarily reducing carbon dioxide and one program in particular is explored this section, after some data analysis.

So far, it has been claimed that China is one of the countries responsible for high coal consumption. In Figure 4, we show that China's position is not as imbalanced as the previous section may suggest. China has been consuming more of every type of energy, in addition to coal. Essentially, China's GDP has been growing at very rapid pace since 2000 and in order to support that growth, all sorts of energy was required. China does not have developed distribution networks, and in many industrial regions there have been few alternatives to coal, a situation might soon revert. The consumption of coal in China has increased every year since the mid-1990s, however as a proportion of total energy consumption, the coal share has declined (Figure 4).

Figure 4 Primary energy consumption in China, 2010 to 2015



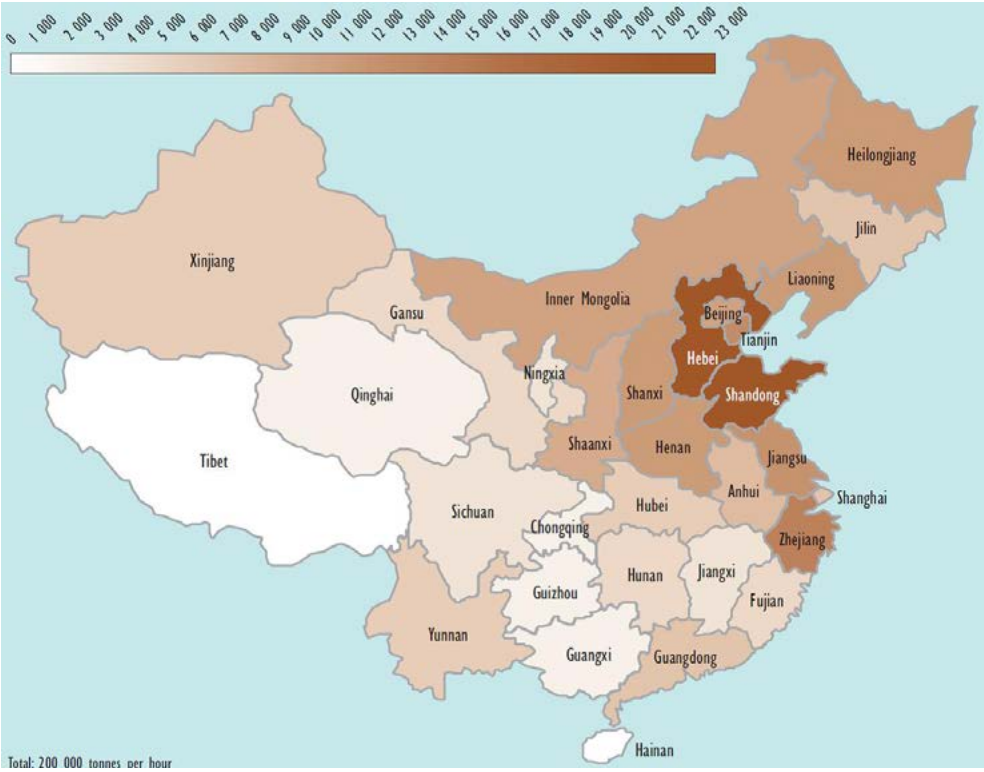
Source: Authors' calculation from International Energy Agency data.

The following case study reviews a plan explicitly developing strategies for coal-for-gas substitution based on information obtained from IEA (2016b). In September 2013, Chinese authorities announced the Action Plan for Air Pollution Control, a program designed to accelerate the conversion of coal-fired boilers and power stations to gas firing. China's National Development and Reform Commission estimated the natural gas consumption increment resulting from coal-to-gas substitution at 112 bcm (billion cubic metres) by 2020. In May 2014, the 2014-2015 Energy Saving and Low-Carbon Development Action Plan was announced, outlining the phase-out of 200,000 tonnes per hour (t/h) of coal-fired boilers by 2015, with targets distributed across provinces as indicated in Figure 5. An additional 200,000 t/h coal capacity reduction is planned for 2018. Altogether, the plan covers about 20 per cent of the 700 mtpa (million tonnes per annum) reported capacity of small coal boilers. The largest coal-to-gas switching has occurred in Beijing, Tianjin, Hebei and Shandong

China's Action Plan for an Air Pollution Control pilot program shows the potential of coal-for-gas substitution, with the main practical limitation being a lack of gas infrastructure.

provinces. Beijing has fully eliminated and banned coal-fired boilers in most suburban areas. It also plans to completely eliminate coal power stations in 2017. In Hebei province, coal has been banned in many industries, under the threat of having their power supply cut off as punishment. The program-related demand for gas in the Beijing-Tianjin-Hebei area will increase from 4.5 bcm in 2015, to 9.5 bcm in 2017, and to 20 bcm by 2020. In Shandong, the plan projects phasing out 3,736 small coal-fired boilers, taking natural gas consumption to 37 bcm by 2020, up from 7.5 bcm in 2014. In Tengzhou, substantial subsidies have been offered to replace coal-burning units. These successful programs are expected to inspire a gradual China-wide coal-for-gas switch. The two main current impediments are gas access (bottleneck in many areas as pipeline networks are inexistent in some cities or areas) and a coal-gas price differential that favours the former. Although China's initial phase has been relatively easy to implement, coal-to-gas substitution in rural China and developing countries in Asia, such as India, remains challenging due to infrastructure constraints. But both Chinese and Indian authorities have identified this process as desirable, and it is expected to drive much of their additional natural gas demand in the future.

Figure 5 Primary energy consumption in China by region



Source: Authors' calculation from International Energy Agency data.

Energy consumption and income: Dynamics and environmental policy

It is no secret that there is high correlation between energy consumption and income. However, this simple association is not fully revealing of important underlying dynamics. The key term that economic empirical literature has focused on is causality. In the context of time series econometrics, causality between two time series indicates that changes to one of them leads to, or causes, changes in the other time series. For two times series X and Y, there are four possible causal links: (I) from X to Y; (ii) from Y to X); (iii) benedictional causality; and (iv) no causal links.

Researchers have been trying to find causality patterns for energy consumption and income, and the results are varied. The reason for such research is the validation or otherwise of hypotheses. According to the literature, the 'growth' hypothesis states that energy consumption causes income or output growth, and it implies that environmental policies that restrict energy consumption may have disastrous effects on output level. Then, we find the 'conservation' hypothesis positing the exact opposite, that is, changes in income that raise the living standards of the population lead to increased energy consumption. According to this hypothesis, environmental policies affecting energy consumption should not significantly affect output. The third and fourth hypotheses postulate a 'feedback' or bidirectional effect, and no directional causality. Although there is no clear consensus in the literature and sometimes results are sensitive to how causality tests are technically implemented, some general observations can be brought here. In a thorough review, Burns, Inchauspe and Trueck (2017) show that, when developed economies are examined, the relationship tends to go from income to energy consumption, or (less often) show bidirectional causality. On the other hand, when developing economies are examined, the causality often goes from energy consumption to income, or (less often) is bidirectional. These results can be verified in Table 2.

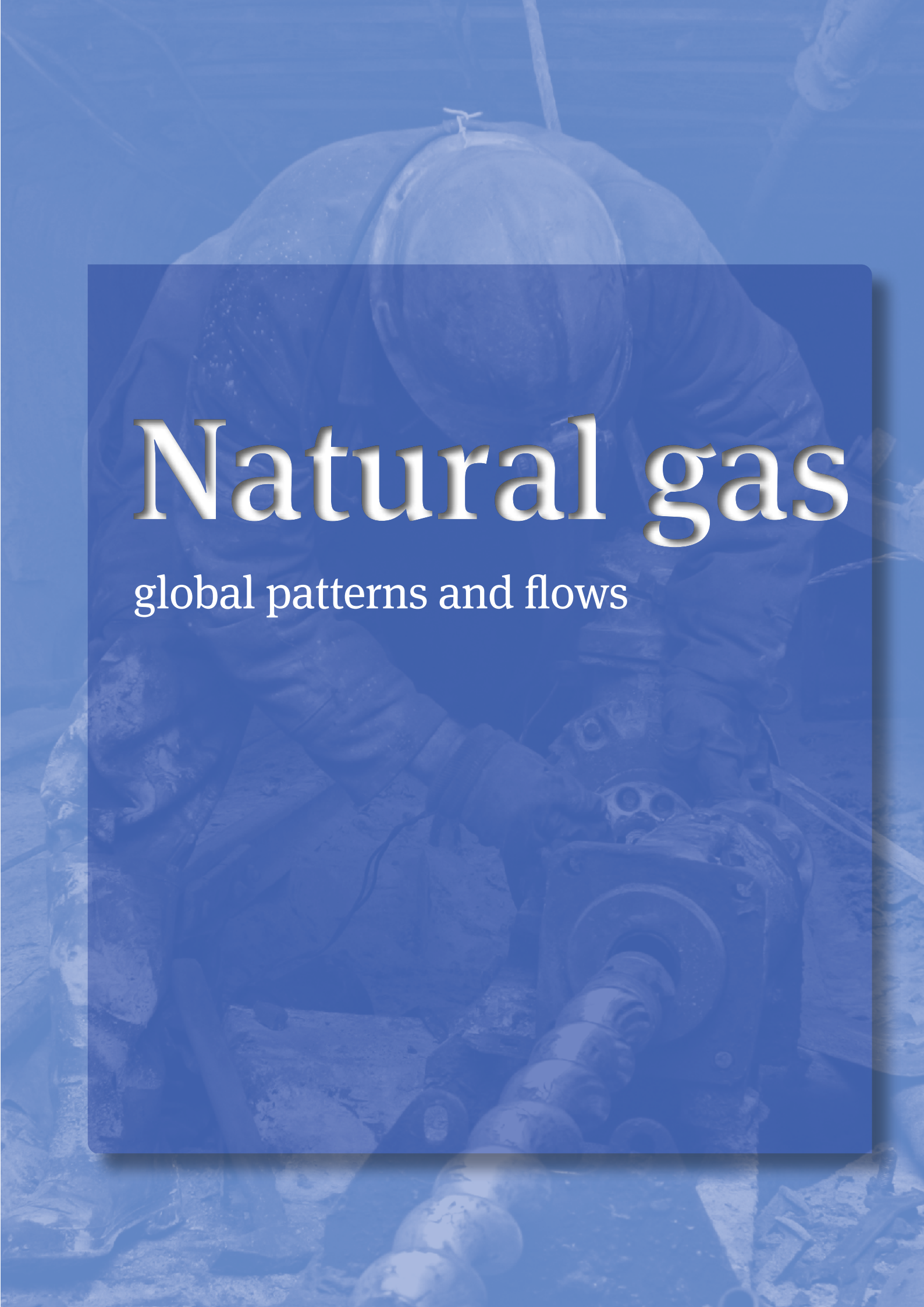
Table 2 **Summary of multi-country studies examining the relationship between energy consumption (E) and income (Y)**

Study	Country(-ies)	Period	Conclusions
Developed countries			
Huang *et al.* (2008)	82 low-, middle- and high-income countries	1972-2002	Low-income countries: Y⇏E Middle-income countries: Y⇒E High-income countries: Y⇒E
Joyeux & Ripple (2011)	30 OECD and 26 Non-OECD countries	1973-2007	OECD: Y⇒E (SR), Y⇒E (LR) Non-OECD: Y⇔E (SR), Y⇒E (LR)
Lee and Chang (2007)	22 developed and 18 developing countries	1971-2002	Developing countries: Y⇒E Developed countries: Y⇔E
Yildirim and Aslam (2012)	17 highly developed OECD countries	1971-2009	Y⇒E (Australia, Canada, Ireland) Y⇐E (Japan) Y⇔E (Italy, New Zealand, Norway, Spain) Y⇏E (Austria, Denamrk, Finland, France, Germany, Sweden, Turkey, US)
Narayan and Smyth (2008)	G-7 countries	1971-2002	Y⇐E (LR)
Soytas and Sari (2003)	G-7 countries	1960-2004	Y⇔E (Canada, Italy, Japan, UK) Y⇒E (Germany) Y⇐E (France, USA)
Developing countries			
Lee and Chang (2008)	16 Asian countries	1971-2002	Y⇏E (SR) Y⇐E (LR)
Chiu-Wei *et al.* (2008)	8 Asian countries and USA	1954-2006	Y⇏E (USA, Thailand, Korea) Y⇒E (Philippines, Singapore) Y⇐E (Taiwan, Hong Kong, Malaysia, Indonesia)
Mehara (2007)	11 major oil exporting countries	1971-2002	Y⇒E (LR)
Wolde-Rufael (2004)	19 African countries	1971-2001	Y⇒E (Algeria, Congo DR, Egypt, Ghana, Ivory Coast); Y⇐E (Cameroon, Morocco, Nigeria); Y⇔E (Gabon, Zambia); Y⇏E (Benin, Congo RP, Kenya, Senegal, South Africa, Sudan, Togo, Tunisia, Zimbawe)
Apergis and Payne (2009a)	6 Central American Countries	1991-2004	Y⇐E (LR)
Apergis and Payne (2009b)	11 Eastern European countries	1991-2005	Y⇔E (SR)
Block *et al.* (2015)	China	1978-2008	Y⇏Electricity, Y⇏Oil, Y⇏Renewable Energy (all in the LR)
Herrerias *et al.* (2013)	Regions of China (cross-sectional data)	1995-2009	Y⇐E (SR, for E=Total energy consumption, electricity consumption) Y⇒E (LR, for E=Total energy, electricity, coal, coke and oil consumption)
Yalta and Cakar (2012)	China	1971-2007	Y⇏E in 53 out of 62 estimations
Fang (2011)	China	1978-2008	Y⇐E E: Renewable energy
Yuan *et al.* (2008)	China	1963-2005	Y⇐Electricity, Y⇐Oil, Y⇏Coal, Y⇏Total energy (all in the SR)
Yuan *et al.* (2007)	China	1978-2004	Y⇐E (SR and LR) E: Electricity consumption
Zou and Chau (2006)	China	1953-2002	Y⇐E (SR, 1985-2002) Y⇔E (LR, 1985-2002)
Shiu and Lam (2004)	China	1971-2000	Y⇐E (SR and LR) E: Electricity consumption

Notes: The symbols ⇒ and ⇐ indicate direction of causality, ⇔ indicates bidirectional causality and ⇏ indicates no causality. SR and LR denote short-run and long-run.
Source: Burns, Inchauspe and Trueck (2017).

Burns, Inchauspe and Trueck (2017) also conduct their own causality tests for oil consumption and income in China. As China is forecast to become the largest oil consuming country in the world by the early 2030s and there is pressure on meeting environmental targets, interest in the nature of the relationship between economic growth and energy consumption in China is receiving growing attention. The study uses quarterly analysis and performs sensitivity analysis for business cycle asymmetries (different treatment for periods of economic expansion and recessions). The robust result is directional causality in the long run. The direct implication is that, in today's China, an environmental policy program that curves oil consumption down is likely to be detrimental to the Chinese economy. The less direct implication of this result is that from coal-to-gas substitution programs or renewable energy incentives may be more cost-efficient policies to attain environmental targets in China.

Empirical academic literature identifying causal links between GDP and energy consumption suggest that environmental policies aimed at reducing energy consumption may be harmful. Looking forward, it will be of interest to observe the evolution of causal links, recommendations and policy actions in Asian economies.



Natural gas

global patterns and flows

Natural gas global patterns and flows

In this chapter, data on global flows of natural gas is used to identify market structures and potential trade opportunities for Australia. We argue that it is important to understand not only the size of demand and supply forces, but also the dynamics and geopolitics of these forces.

Proven natural gas reserves

An important indicator of availability of an exhaustible resource is its reserve level. However, reserves should be interpreted with care. For the purposes of this report, proved reserves are quantities of resource from known reservoirs that, with reasonable certainty, that could be recovered in the future under current economic and operating conditions. This definition is widely used by industry, government and international organisations to conduct investment activity and policy analysis.

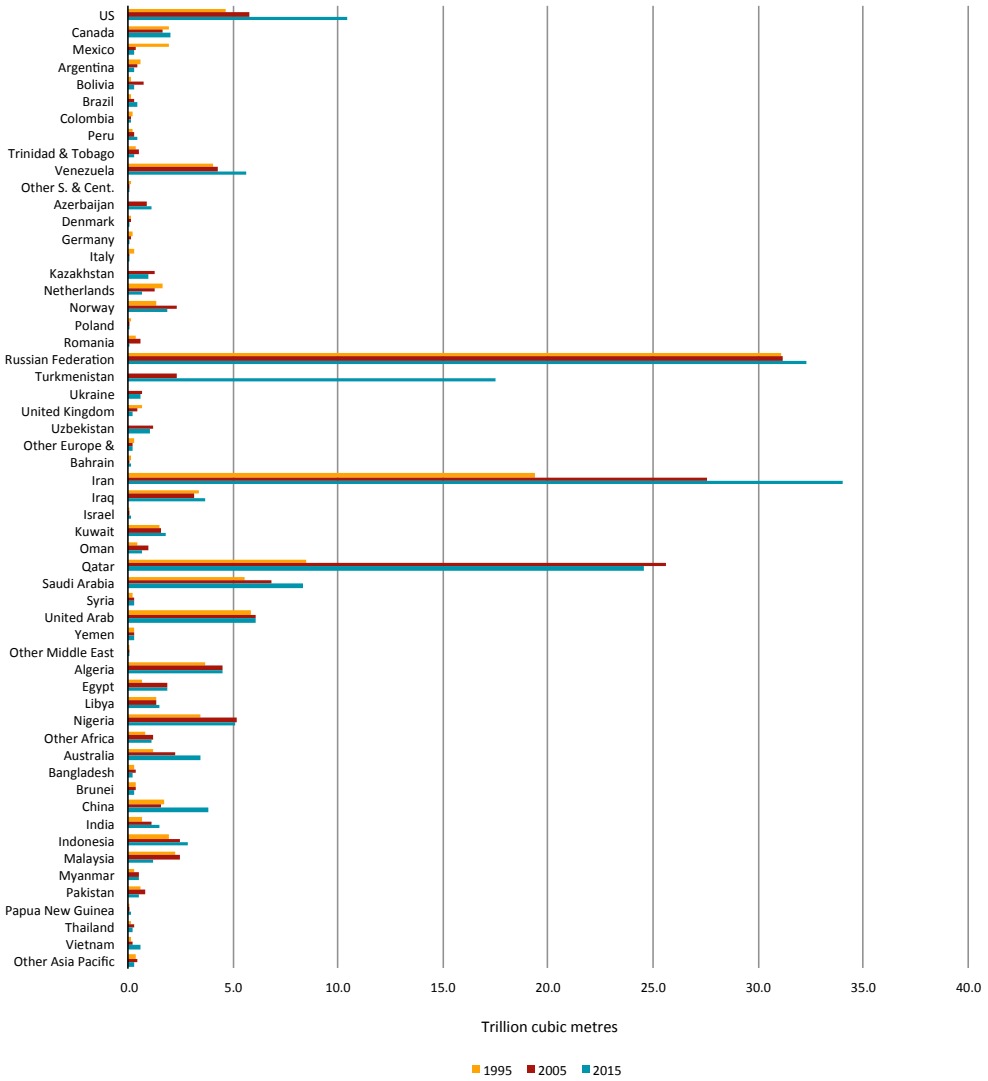
There are two general remarks that often lead to confusion among non-specialists. First, the level of proved reserves varies and often increases over time. According to the data displayed in Figure 6, the level of gas proved world's reserves increased from 119.9 tcm (trillion cubic metres) in 1995, to 157.3 tcm in 2005, and then to 186.9 tcm by the end of 2015. From the definition we are applying, it is clear that the level of proven reserves depends, to a great extent, on market prices, the level of investment in exploration, development activities and technology. So, the level of proven reserves should not be interpreted as a resource stock level that can only decline over time. The second clarification is that our definition of proved reserves should not be confused with alternative definitions used by private companies or state-owned enterprises. These definitions may vary, for example, in the degree of certainty criterion and economic assumptions. For instance, the US Securities and Exchange Commission allows listed firms to report wider definitions (e.g. 2P and 3P reserves, see SEC, 2008), in addition to the 1P category that basically tallies with the definition provided above.

The level of natural gas proven reserves is essentially a dynamic measure that depends on the level of investment, technology and other economic conditions.

In recent years, technological advancements (that will be covered later in this report) for development of previously non-economically-recoverable natural gas -especially unconventional natural gas- led to an unprecedented, major change in natural gas markets. In particular, the new technologies for extracting shale gas acted as a game-changer, re-distributing regional market power and energy market definitions. Technologies for developing tight gas have also played an important role. Some of the most significant producers have been able to increase their level of proved reserves to levels never seen before. To quantify these impacts, we can consider some countries from Figure 1. The US has been able to more than double its reserves of natural gas (from 4.7 tcm in 1995 to 10.4 tcm in 2015). Qatar's reserves increased by 188 per cent in the period 1995 to 2015 (from 8.5 tcm to 24.5 tcm). Iran's reserves increased by about 590 per cent in 1995 to 2015 (from 19.4 tcm to 134.0 tcm). Turkmenistan increased its reserves from a near nil level in 1995 to 17.5 tcm in 2015, and a marginal increase was observed in Russia. Altogether, US, Qatar, Iran, Turkmenistan and Russia possess 71.7 per cent of proved natural gas reserves around the world. China's level of reserves also increased substantially (from 1.7 tcm in 1995 to 3.8 tcm in 2015), but it accounts for only 2.1 per cent of world reserves, and China is expected to continue to rely heavily on natural gas imports in the near future. Australia's natural gas reserves have increased from 1.2 tcm in 1995 to 3.5 tcm in 2015. Although this represents only 1.9 per cent of the world's reserves, its strategic LNG trade links in combination with its relatively small population make gas a very important element of its economy. It needs highlighting that the level of proved reserves is sensitive to technological advancements which could make an otherwise economically unexploitable reservoir commercial. In line with the recent technological advancements that continue to rapidly improve and spread, we would expect the level of international reserves to further increase in the next decade, although low gas prices might prevent immediate development. Unconventional gas resources have contributed to the expansion of proven reserves. Despite some of the technical challenges and environmental sensitivities associated with hydraulic fracturing, supply is expected to rise and play an increasingly important role in meeting global demand requirements.

New technologies allowing for extraction of shale and other unconventional gas and oil resources have acted as a game changer, shifting geo-economic power and re-defining markets.

Figure 6 Allocation of global natural gas reserves, in trillion cubic metres, 1995 to 2015



Source: Authors' calculation from International Energy Agency and BP data.

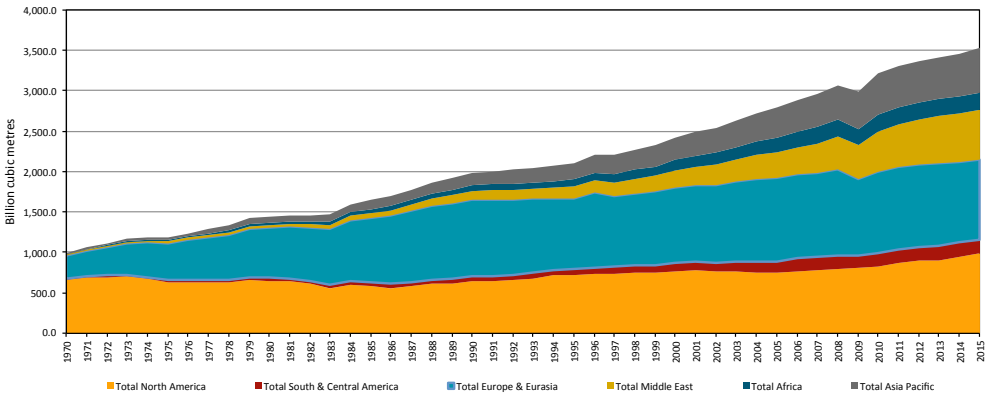
Natural gas production

The production of natural gas does not necessarily mirror the availability of natural gas reserves. There are several factors affecting the development of natural gas. First, the physical connections between net consumers and producers of natural gas, i.e. pipelines and LNG processing facilities, are limited. Second, there are capital movement and trade restrictions (including high tariffs) that apply to some nations. Third, some economies are subject to high degrees of uncertainty about economic conditions and policies that prevent long-run investment (sovereign risk), particularly in developing countries. Fourth, some countries lack adequate networks for distributing natural gas. Naturally, there are many other factors affecting gas production patterns, such as taxation, renewable energy subsidisation and environmental policies. Overall, what is important to understand is that natural gas markets are essentially regional.

Physical interconnections between regions that produce and consume natural gas are heavily constrained, leading to regionalised markets.

As explained, the production of natural gas takes place only if, among other things, there is physical access to where the demand is located. In the case of the Asia Pacific region, most of its natural gas production is consumed locally, and most of the trade is intra-block trade. Asia Pacific's economic growth has been high since beginning of the 1990s, and subsequently there has been high demand for energy, including energy produced from natural gas. Figure 7 clearly shows that Asia Pacific plays an important role in defining the growth rate of the total world's production of natural gas. Global production of natural gas has grown at an equivalent 2.87 per cent per annum between 1970 and 2015. If the Asia Pacific region was excluded from the world's production, the average growth in the rest-of-world production in 1970 to 2015 would have been 2.51 per cent per annum. The average growth rate in Asia Pacific alone was 8.23 per cent per annum. (See Appendix for calculation details.) The second main driver of high-growth of gas production is the Middle East (Figure 2). In North America, there has been overall steady growth since the 1990s, accelerating in 2010 to 2015. Africa and South and Central America exhibit high growth however they have a relatively small share of total production. Finally, Figure 7 demonstrates that the production of natural gas in Europe and Eurasia has remained approximately constant, but significant, since 2000.

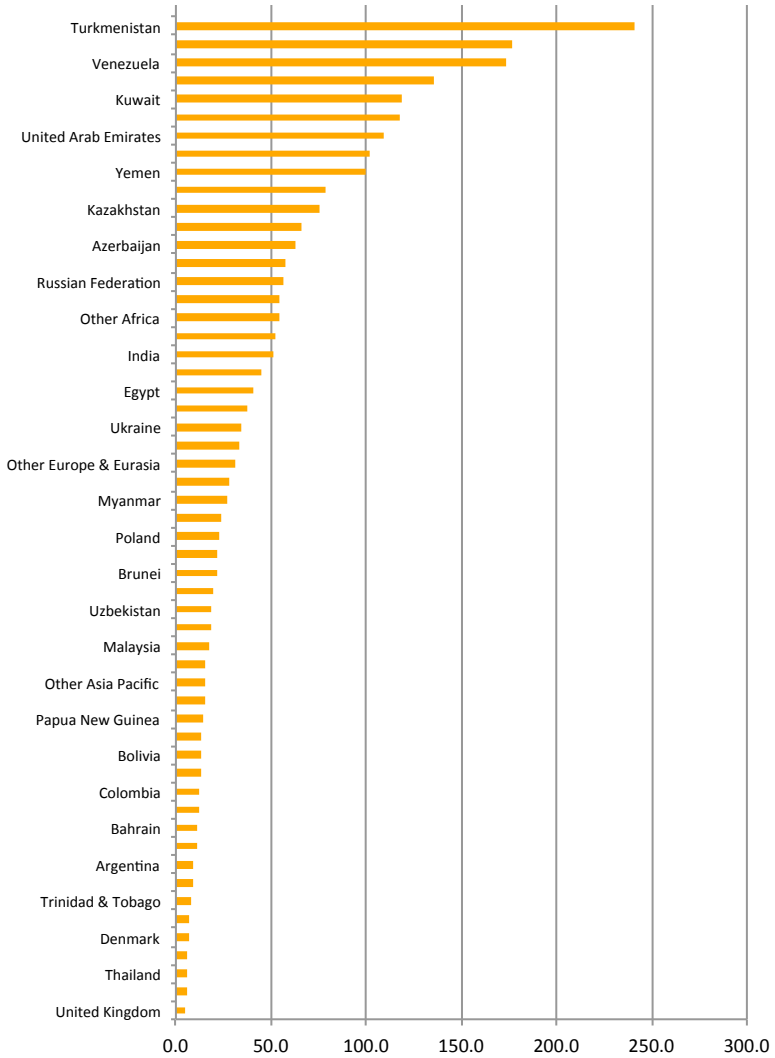
Figure 7 Annual production of natural gas, in billion cubic metres, 1970 to 2015



Source: Authors' calculations from International Energy Agency data.

To further illustrate the connections between production and proven reserves, we employ Figure 8. The ratio between proved reserves and production can be interpreted as the number of future years of production that could be sustained with the current level of proved reserves. Again, this ratio should be interpreted with care. It does not systematically decrease each year and, depending on the technology and economic conditions, it can further increase in the future. With 3.7 tcm of proved reserves, Iraq has a staggering reserves-to-production ratio of over 4,600 years; however, this figure is affected by limited current production due to domestic political turmoil. In the Middle East, the combination of easily explorable natural resources and relatively moderate production lead to high ratios. In the US, the production of newly available reserves has led to a modest ratio of 13.6 years. Compared to the US, shale reserves in Australia remain relatively underdeveloped. Nevertheless, Australia's relatively abundant conventional gas reserves lead to a ratio of over 50 years.

Figure 8 Global proved-reserves-to-production ratio



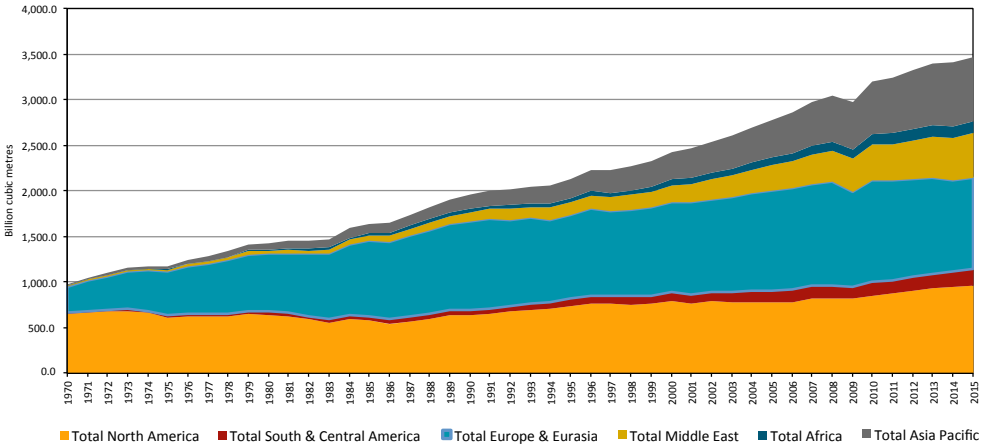
Notes: Elaborated from data used in Figures 1 and 2. * The value for Iraq is 4,625 and is not displayed.
Source: Authors' calculation from International Energy Agency data.

Natural gas consumption

The regional consumption patterns in Figure 9 can be compared to the production patterns in Figure 7 to obtain an overall idea of how the identified block countries trade in the real world. Despite its fast-growing level of regional production (8.23% p.a. during 1970-2015), the demand for natural gas in the Asia Pacific region has grown at an even faster rate (8.89% p.a.), resulting in a net demand for imports of natural gas from other regions. Other regions also contribute towards demand growth, with Europe and Eurasia being a noticeable exception. As shown in Figure 3, Europe and Eurasia annual gas consumption level remains approximately constant at about 1,000 bcm. This pattern is also observed in the region's consumption of crude oil, and it is generally attributable to the conjunction of improved efficiency, low population growth, and environmental policies. Overall, the gas demand dynamics are mainly driven by Asia Pacific and the Middle East, whereas Africa and the Americas contribute moderate growth.

Natural gas consumption growth in Asia Pacific, averaging 8.89% p.a. in 1970-2015, has been the main driver of global demand growth.

Figure 9 Global annual consumption of natural gas, in billion cubic metres, 1970 to 2015



Source: Authors' calculations from International Energy Agency data.

Natural gas consumption in Asia Pacific, and the role of China

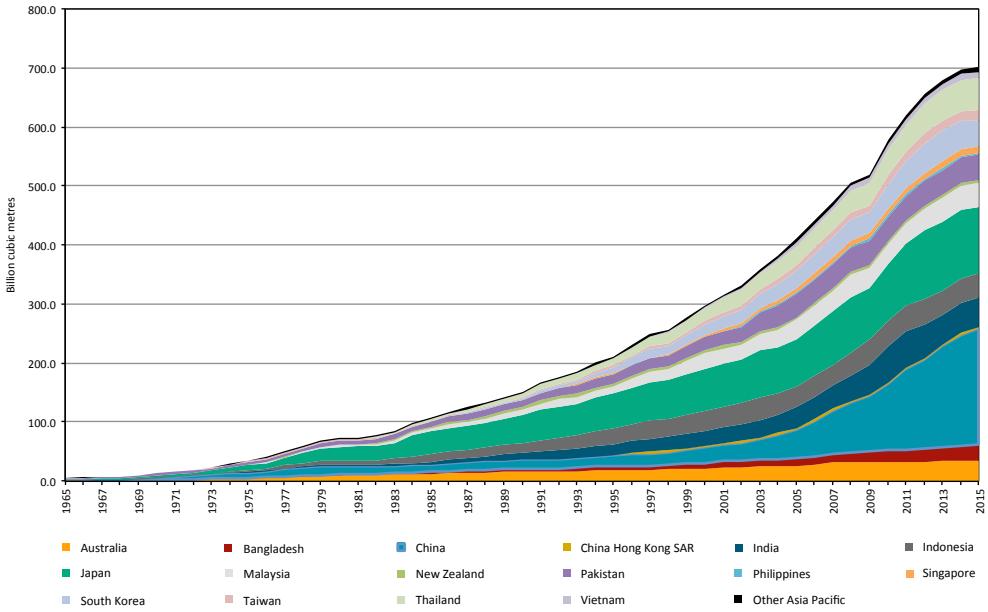
Because understanding the role of demand-driving forces within the Asia Pacific region is of vital importance, its demand is decomposed in Figure 10. There, two clear patterns can be identified. First, there is steady consumption growth that applies to all countries during the period 1970 to 2015. If we exclude China, the consumption of natural gas in the rest of the countries has grown gradually from an almost negligible level in 1970 (11.6 bcm) to 503.8 bcm in 2015.

A second important pattern stands out when examining China by itself, which appears to adopt a distinctively higher growth rate from 2003 onward. The tenth Five-Year Plan for 2001-2005 addressed the need of improving China's energy structure organisation. In 2004, the West-East Pipeline was completed covering a distance of 3,900 kilometres, which was instrumental in transporting inland domestic gas to the coastal cities. Further, city distribution networks and urbanisation facilitated the penetration of natural gas. Although households' consumption of natural gas has generally increased in China, the industry sector has been the main driver of the observed high-paced increased in demand, particularly in the petro-chemical and power sectors. The reforms also included plans to promote LNG and pipeline importation of natural gas. In 2003, China opened its first LNG regasification facility in the city of Guangdong, a city with a major industrial agglomerate that is often called 'the factory of the world'. The facility was operated by China National Offshore Oil Corporation (CNOOC), who secured a long-term contract with Australia NWS. The very first LNG cargo arrived from Australia at the Guangdong Dapeng LNG terminal in 2003. By the end of 2008, this terminal had received a total of 3.7 bcm. From 2003 to date, a number of LNG re-gasification facilities have been opened by CNOOC and China National Petroleum Corporation (CNPC). The most significant inflow of natural gas into China comes from Turkmenistan through pipelines (and it accounts for 46% of total imports). Other imports come from Qatar (16%), Australia (13%), Malaysia (7%), Indonesia (6%) and Uzbekistan (6%).

China has been the main contributor to natural demand growth in Asia Pacific. Imports are diversified with Australia supplying 13% in the form of LNG.

Natural gas policies in China have been developed with two main criteria in mind. The first one is to diversify the supply of imported gas. In practice, LNG terminals have been the main instrument facilitating supply diversification. Pipeline negotiations have proven to be complicated, especially if more than two countries are involved. The second main objective is to provide natural gas supply security, and this is generally achieved with long-term contracts. For instance, CNOOC signed a sales and purchase agreements (SPAs) with Australia NWS and Australia QC LNG to guarantee supply for 25 and 20 years (commencing in 2009 and 2014), respectively (Higashi, 2009).

Figure 10 Consumption of natural gas in Asia-Pacific region, in billion cubic metres, 1965 to 2015



Source: Authors' calculations from International Energy Agency data.

Natural gas trade

International trade of natural gas occurs through two main channels: pipeline transportation and in liquefied form. Liquefied natural gas is shipped and requires re-gasification and storage facilities at destination. The resulting interaction between trade partners is complex, and the trade possibilities are limited by the availability of infrastructure. Table 1 summarises the main exporting and importing activities for the most active trading countries occurring through pipelines, and Table 2 is the equivalent for LNG trade. Crossborder pipeline flows grew from 700.2 bcm in 2011 to 704.1 bcm in 2015. On the other hand, LNG flows grew from 329.3 to 338.3 bcm in the same period.

LNG trade is particularly relevant in Asia Pacific. In 2015, of the 338.3 bcm LNG imports observed at the global level, 238.6 bcm were absorbed by Asia Pacific countries. During that year, pipeline imports by Asia Pacific countries accounted for 61.2 bcm (and 33.6 bcm were Turkmenistan exports to China). In other words, 79.6 per cent of gas imports in Asia Pacific countries in 2015 were in liquefied form, and only 20.4 per cent came from pipelines. The growth of LNG trade has also exhibited significant growth in Asia Pacific countries: it increased from 206.3 bcm in 2011 to 238.6 bcm in 2015.

Showing the export destinations and countries of origin from each single country in Tables 3 and 4 is tedious and impractical. For that reason, the major trade flows are summarised graphically in Figure 11.

Table 3 **Summary of global natural gas trade flows occurring through pipelines, in billion cubic metres, 2011 to 2015**

	Pipeline imports (billion cubic metres)						Pipeline exports (billion cubic metres)				
	2011	2012	2013	2014	2015		2011	2012	2013	2014	2015
US	88.3	83.8	78.9	74.6	74.4	US	40.7	45.1	44.4	42.4	49.7
Canada	26.6	27.5	25.8	21.8	19.8	Canada	88.2	83.8	78.9	74.6	74.3
Mexico	14.1	17.6	18.6	20.6	29.9	Mexico	0.1	-	0.0	†	†
Trinidad and Tobago	-	-	-	-	-	Trinidad and Tobago	-	-	-	-	-
Other S. & Cent. America	14.8	16.9	18.6	18.7	18.5	Other S. & Cent. America	14.8	16.9	18.6	18.7	18.5
France	32.3	35.0	30.5	28.6	35.9	France	2.2	1.2	1.1	1.9	1.6
Germany	84.0	86.8	98.4	88.4	104.0	Germany	11.7	12.5	15.1	20.0	29.0
Italy	60.8	59.7	51.6	46.6	50.2	Italy	0.1	0.1	0.2	0.2	0.2
Netherlands	15.6	14.5	21.5	23.2	30.2	Netherlands	50.4	54.5	51.3	46.1	40.6
Norway	-	-	0.0	†	†	Norway	95.0	106.6	102.4	102.4	109.5
Spain	12.5	13.3	15.3	17.0	15.2	Spain	0.5	0.7	0.9	†	0.5
Turkey	35.6	34.9	38.2	41.1	39.7	Turkey	0.7	0.6	0.6	0.6	0.6
United Kingdom	28.0	35.4	40.0	29.4	29.0	United Kingdom	16.0	12.0	9.0	10.0	13.4
Other Europe	100.8	97.6	99.5	102.4	97.2	Other Europe	10.1	9.3	11.8	8.9	13.1
Russian Federation	30.1	29.8	27.0	24.2	16.9	Russian Federation	207.0	185.9	212.0	187.7	193.0
Ukraine	40.5	29.8	25.0	17.5	16.2	Ukraine	-	-	-	-	-
Other CIS	35.3	32.3	32.2	30.3	29.8	Other CIS	63.0	68.8	67.1	69.0	64.5
Qatar	-	-	-	-	-	Qatar	19.2	19.2	19.9	20.5	19.8
Other Middle East	32.1	29.2	25.5	27.4	27.3	Other Middle East	9.1	8.4	9.4	9.6	8.4
Algeria	-	-	-	-	-	Algeria	34.4	34.8	28.8	25.4	25.0
Other Africa	5.7	6.0	7.2	8.8	8.9	Other Africa	8.3	11.0	9.3	10.9	11.1
China	14.3	21.4	27.3	31.3	33.6	China	3.1	2.8	-	-	-
Japan	-	-	-	-	-	Japan	-	-	-	-	-
Indonesia	-	-	-	-	-	Indonesia	9.3	10.2	10.0	9.7	10.5
South Korea	-	-	-	-	-	South Korea	-	-	-	-	-
Other Asia Pacific	28.6	34.1	26.4	25.4	27.6	Other Asia Pacific	16.3	21.0	16.7	18.7	21.0

Notes: † Less than 0.05.
Source: Authors' calculation from International Energy Agency and BP data.

Table 4 **Summary of global natural gas trade flows in liquefied (LNG) form, in billion cubic metres, 2011 to 2015**

	LNG imports (billion cubic metres)						LNG exports (billion cubic metres)				
	2011	2012	2013	2014	2015		2011	2012	2013	2014	2015
US	10.0	4.9	2.7	1.7	2.6	US	1.7	0.8	0.1	0.5	0.8
Canada	3.3	1.8	1.1	0.5	0.6	Canada	-	-	-	-	-
Mexico	4.0	4.8	7.8	9.4	7.1	Mexico	-	-	-	-	-
Trinidad and Tobago	-	-	-	-	-	Trinidad and Tobago	18.5	19.1	19.8	18.4	17.0
Other S. & Cent. America	10.6	15.2	19.6	20.9	20.0	Other S. & Cent. America	5.2	5.8	5.7	5.8	5.0
France	15.5	10.3	8.7	7.2	6.6	France	-	0.2	0.6	0.5	0.4
Germany	-	-	-	-	-	Germany	-	-	-	-	-
Italy	8.7	7.1	5.5	4.6	6.0	Italy	-	-	-	-	-
Netherlands	0.8	0.8	0.8	1.1	2.0	Netherlands	-	-	0.2	0.6	1.2
Norway	-	-		-	-	Norway	4.5	4.7	3.8	5.3	6.0
Spain	24.2	21.4	14.9	15.5	13.1	Spain	0.8	1.2	2.6	5.1	1.6
Turkey	6.2	7.7	6.1	7.3	7.5	Turkey	-	-	-	-	-
United Kingdom	24.8	13.7	9.4	10.7	12.8	United Kingdom	0.1	-	-	-	0.3
Other Europe	10.9	8.2	6.0	5.4	7.1	Other Europe	0.6	1.7	1.6	2.1	1.4
Russian Federation	-	-	-	-	-	Russian Federation	14.2	14.8	14.2	14.3	14.5
Ukraine	-	-	-	-	-	Ukraine	-	-	-	-	-
Other CIS	-	-	-	-	-	Other CIS	-	-	-	-	-
Qatar	-	-	-	-	-	Qatar	100.4	105.4	105.6	102.9	106.4
Other Middle East	4.6	4.6	4.5	5.4	10.5	Other Middle East	28.2	25.9	28.5	27.1	19.8
Algeria	-	-	-	-	-	Algeria	17.8	15.3	14.9	17.5	16.2
Other Africa	-	-	-	-	3.8	Other Africa	40.0	38.8	31.6	31.9	32.5
China	16.6	20.0	24.5	26.5	26.2	China	-	-	-	-	-
Japan	107.0	118.8	119.0	122.9	118.0	Japan	-	-	-	-	-
Indonesia	-	-	-	-	-	Indonesia	29.3	25.0	22.4	21.8	21.9
South Korea	50.6	49.7	54.2	48.6	43.7	South Korea	-	-	-	0.2	0.3
Other Asia Pacific	32.1	38.8	40.4	44.6	50.7	Other Asia Pacific	68.7	69.0	73.5	78.4	93.0

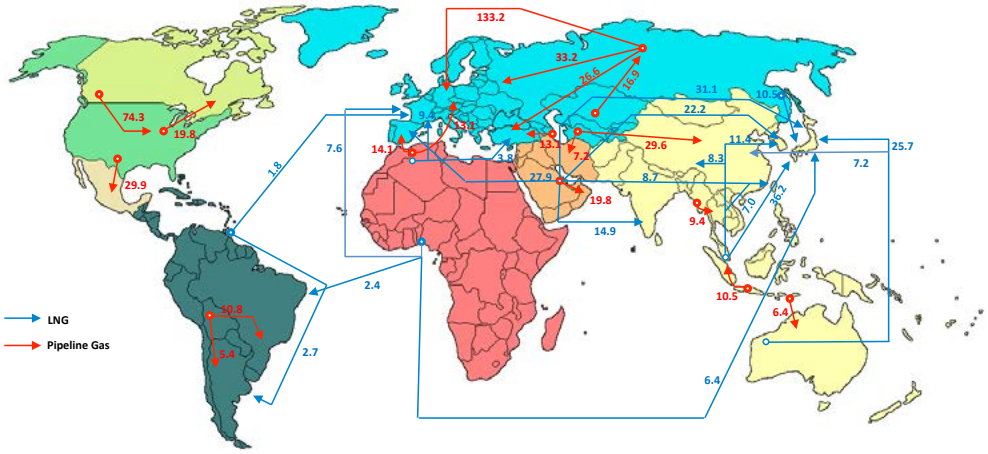
Source: Authors' calculation from International Energy Agency and BP data.

The rise of gas demand, particularly in Asia, is partially explained by the significant number of new LNG projects coming on stream. Most of the new LNG capacity additions come from North America and Australia, with much of the LNG intended for delivery to Asia. Qatar and Russia are very large suppliers but –as will be explained – have opted to secure volumes and not grown significantly. Qatar is by far the largest exporter, as it has been over the past ten years, accounting for nearly a third of the total in 2015. Australia's growing exports made is the second largest supplier – having been third in 2014 – with 12 per cent of the total in 2015, followed by Malaysia at 10 per cent, Nigeria at 8 per cent, Indonesia at 7 per cent, and Algeria and Trinidad at 5 per cent each.

Southeast Asia has only recently become a net gas importer in order to fuel its domestic development. In 2013, the region was a net exporter of 54 billion cubic meters of gas or 5.2 billion cubic feet per day. By 2040, IEA (2016a) forecasts the region will be a net importer of approximately 10 billion cubic meters per year. South Asia in the meantime still faces prolonged power shortages. For instance, Pakistan faces a gas shortage, even after commissioning its first floating storage and regasification unit (FSRU) earlier on this year. Bangladesh is also in the same boat with an estimated 500 million cubic foot per day shortfall on its demand.

With demand growth for LNG easing up in China, LNG sellers are hoping for a new powerhouse to emerge. All eyes are set on South Asia and South Eastern Asia, where potential demand growth looks promising with aspiration to move away from burning oil, paired with government support for LNG and declining domestic production. Markets such as Pakistan, Indonesia, India and Jordan that are emerging as major importers of LNG are seen as major potential destinations. In the current market, floating import terminals are considered the safest option as they can be transported near to markets that would otherwise be hard to access. Floating facilities offer the risk-reducing advantage that they can be recalled if the endeavour is not successful or profitable. This approach enables the sunk costs of schemes to be significantly reduced as investment in infrastructure is not lost if the incumbent project does not succeed. Given this, the popularity of floating terminals is expected to grow significantly relative to the traditional land-based terminals of the past few years.

Figure 11 **Main natural gas trade flows globally, in billion cubic metres, 2015**



Source: Authors' calculation from International Energy Agency and BP data.

Natural gas markets:

Regionalisation, pricing and LNG trade

Natural gas markets: Regionalisation, pricing and LNG trade

A key finding from the previous chapters is that gas markets are typically regional, and imperfectly linked. This chapter analyses the emerging market structures from this process, and the pricing mechanisms for traded natural gas. Special attention is given to the evolution of LNG trade.

Implications of regionalisation of gas markets: Pricing

With transport costs constituting a high proportion of delivered prices, there is no reason to think that natural gas markets should converge to a single a price. Not surprisingly, Figure 7 reveals evidence of price differentials across the major trading hubs in North America, Asia and Europe. All the main reference prices in Figure 7 tended to move together until 2008-09. Traditionally, when gas markets were underdeveloped, oil prices were used as common reference. The method reflects how much the price of gas will change given a change in the price of crude oil. Oil prices changed smoothly in the early 2000s, but erratic behaviour from 2008-09 to date have triggered partial decoupling between oil and gas prices, as have technological improvements in LNG which expanded international trade.

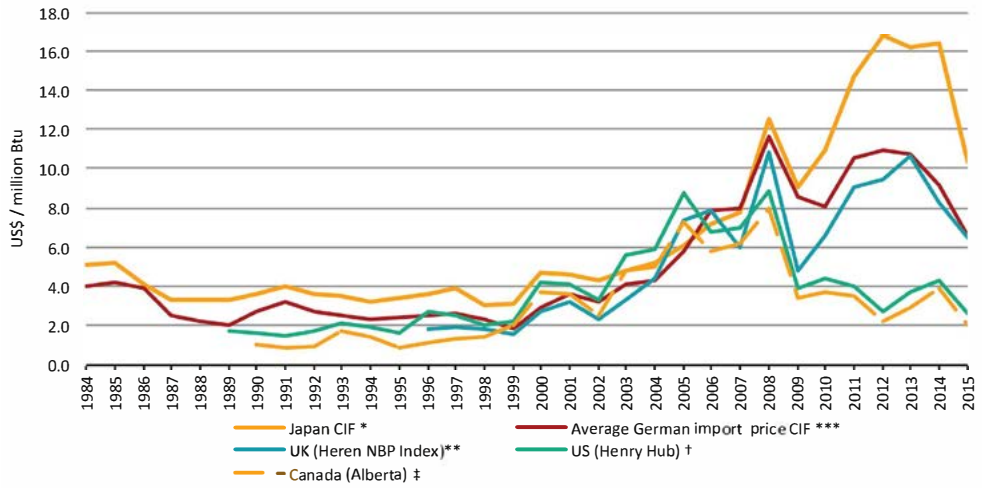
The world's imperfectly-linked regional natural gas markets lead to distinctive pricing mechanisms in North America, Europe and Asia Pacific.

North America has developed a competitive market where the price tends to be determined by the market fundamentals of supply and demand. In Asia, where LNG trade dominates, gas prices tend to be still tied to oil prices. Europe trades both pipeline and liquefied gas, and its regional price has shown some signs of decoupling from the oil price.

In technical terms, contracts which are purely determined in bi-lateral negotiations form a 'bilateral monopoly', but these contracts are rare. Natural gas prices that are set based on natural gas demand and supply forces are referred to as 'gas-on-gas' contracts; the US and to a lesser extent the European market fall under this category. In Asia, contracts are linked to oil prices by contractual formula, but the margins are negotiable and set bilaterally on a contract-by-contract basis. Recently, some integration of Asian markets has been observed, and there is a slow but ongoing trend towards gas-on-gas pricing (Inchauspe, 2014).

Figure 12 demonstrates that the price divergence observed from 2011 to 2014 has narrowed significantly. Converging prices can generally be explained by the growing supply overhang of natural gas and LNG, lacklustre gas demand over the past few years, and the oil price drop for the case of European and Asian prices. As noted, the oil indexation mechanism is still used in the latter two markets, to varying extents, for the pricing natural gas supply. In 2015, around 27 per cent of global gas trade could be classified as spot trade – a moderate increase over the past five years – with the remainder based on oil indexation. Producers, including those in Australia, might adapt to the evolving circumstances and currently oversupplied market by offering customers flexibility in pricing, length of contracts and destinations.

Figure 12 Main regional natural gas prices, in $US per million Btu, 1984 to 2015



Sources: *, ** Thomson Reuters DataStream.
*** 1984-1990 German Federal Statistical Office; 1991-2015 German Federal Office of Economics and Export Control (BAFA).
† ICIS Heren Energy Ltd.
‡ Energy Intelligence Group, *Natural Gas Week*.

Natural gas pricing in North America

Policies addressing third-access-party have been instrumental in the development of a competitive natural gas market in the US, but it took decades to achieve this status.

In North America, the natural gas markets are highly developed, competitive and integrated. The US has a highly-integrated pipeline network connecting almost all corners of the country. This network is interconnected with Canada and, to a lesser extent, Mexico. Prices in North American natural gas contracts are tied to the price of natural gas quoted at the Henry Hub in Louisiana. For instance, Figure 7 shows the average price in Alberta, Canada –another major trading hub – which moved on par with the Henry price reaching levels below US$3 per Btu in 2015. The competitiveness in North America was visible as early as the mid-1980s, but if something is to be learned from the North American experience it is that it takes many years to establish a fully-functional natural gas market.

A glimpse of the coal to gas transition is provided by the US experience in recent years. A narrowing gas and coal price differential in energy terms has been observed since 2008, with the gas price at times falling below the coal price, including throughout 2016. Gas use in electrical power generation has risen in consequence, while coal use has decreased.

One crucial factor encouraging both investment and competition in the North American market has been its regulatory framework, in particular, regarding third party access (TPA) to infrastructure. In line with earlier antitrust legislation in the US, natural monopolies are discouraged in natural gas markets, and owners of pipelines and some other infrastructure are required to provide access to third parties at the marginal usage cost (a well-established practice in competition policy). There are three main federal regulatory statutes for oil and gas pipelines in the US: The Natural Gas Act (NGA), the Interstate Commerce Act (ICA) and the Outer Continental Shelf Lands Act (OCSLA), with the former being the main one for natural gas networks. The NGA was enacted in response to perceived monopolies in the 1920s and applies to pipelines that transport natural gas 'for resale' in operations that involve 'natural gas companies'. Essentially, the NGA guarantees access to existing networks to all gas producers at a 'just and reasonable' rate, and equal treatment of firms (no 'undue preference' or 'unreasonable rate difference' is allowed). With the same spirit, the Federal Energy Regulatory Commission (FERC), state-level regulations and cross-border treaties have established TPA policies for pipeline and storage access that have contributed to the development of the market and encouraged relatively small producers to participate. In general, natural gas trade between North America as a block and other regions of the world has been very limited. However, the recent growth in unconventional reserves in North America is expected to lead to increased LNG exports and the price gap between regions would then be expected to narrow down.

With current LNG terminals under way, the US is set to become a major destination-flexible supplier of FOB LNG.

With the widening of the Panama Canal and international LNG prices that are above the Henry hub levels, the US is positioned to become a major 'destination flexible' supplier of FOB LNG. The first project to materialise was Cheniere Energy's Sabine Pass, which made its first shipment, from Louisiana to Brazil, in February 2016. Although the US currently plays a small role in the global LNG markets, numerous projects have been approved for exports by the US authorities, with many targeting major markets in Asia. By mid-2016, the US Department of energy had received 25 applications for LNG projects, with a potential addition of 423 bcm per annum to current export capacity. Six of these projects are currently under construction and total approved export capacity stands at approximately 110 mtpa, with nearly two thirds of that under construction. Overall, the comparative advantage of US LNG is that it can be offered at a relatively low price, namely, the Henry Hub price plus liquefaction and transportation costs and tariffs.

Natural gas pricing in Europe

In Europe, pipeline gas trade dominates, but LNG trade is still significant (Tables 3 and 4). Historically, TPA polices in Europe have never been as well-established as in North America, and European markets have tended to be dominated by large enterprises of significant market power. Consequently, Europe has been regarded as a more oligopolistic market with considerable government participation at all stages of the supply chain. Compared to an idealistic, competitive outcome, oligopolies are associated with restricted output, higher prices, and smaller welfare gains for market participants. In the past, Europe's contracts have been closely linked to fuel oil, and slowly moved towards gas-on-gas pricing in key trading hubs. For instance, UK's National Balancing Point (NBP) – a virtual price within the UK pipeline grid – is commonly used as a gas-on-gas pricing benchmark in some parts of Europe.

The evolution of supply patterns in Europe has evolved over time, generally transitioning to more competitive outcomes. In the past two decades, supply from Norway, Russia and Eastern Europe into Poland, Germany and Central Europe has been characterised by complex multi-lateral negotiations with distinctive price patterns. In the last five years, increased supply from the Middle East and North Africa has pushed prices down. Generally speaking, investment in exploration activities has been very limited in Europe. This is due to not only the red-tape gas distribution barriers, but also lack of demand growth, and policies. Figure 9 demonstrates that gas consumption in Europe stagnated in the mid-1990s, with no significant increment ever since. Low natural gas demand growth is actively encouraged by policy makers in Europe, through various environmental policies that are often associated with low fossil fuel consumption targets. The end result of the interplay of all the factors described so far is a price level that is neither as high as the demand-pushed prices in Asia, nor as low as competitive prices in North America. The main reference prices in Germany and the UK in Figure 12 are indicative of that.

At Europe's most liquid hub, the UK National Balancing Point (NBP), natural gas prices moved in the $8-to-$11-per-mbtu band during 2011 to 2015. By mid-2016, prices were pushed down to $5, much in line with German border prices, due to stagnating European gas demand. Relative to North American prices, European prices attracted US LNG suppliers and development of import infrastructure and active trading hubs. In 2016, European prices have become more attractive relative to historical levels against (oil-indexed) Asian LNG prices.

Overall, LNG in Europe has been used to 'clear' price differentials across major European hubs through arbitrage, and the resulting prices have been generally lower than LNG prices in Asia Pacific. Still, European prices are attractive to suppliers situated in North America, the Middle East and Russia. With gas production in Europe expected to decline, and renewable energy expected to grow at a rate lower than demand, there will be increased demand for gas imports. LNG from US and smaller suppliers in the Middle East and North Africa are set to fill this gap, and there is no major reason to believe that Russia's 30 per cent market share in the European gas market will be substantially affected. It is noteworthy that even though gas prices have fallen in Europe, coal prices have fallen even more, making it difficult for gas to gain further penetration in the energy mix at present.

Considered the 'last resort' market, the European market is characterised by under used import infrastructure, active trading hubs, and a desire to diversify away from Russian gas imports. The latter has been so far achieved with negotiations with US exporters. It could perhaps one day be a potential future destination for Australian LNG. However, the current scenario shows no signs of substantial demand growth in Europe or shortage of cheap US LNG, meaning that the potential for Australian suppliers is relatively small.

Natural gas prices in Asia Pacific: The oil link

In Asia, the natural gas market is very different. Cross-border trade in Asia is nominated by LNG contracts. Since the LNG trade inception in Asia, contracts have been contractually indexed to crude oil. The Japanese Custom-Clear (JCC) crude price – a monthly average of a basket of various crudes imported into Japan – is commonly used as a pricing instrument in these contracts. LNG trade started in Japan in 1969 with supply from Alaska and quickly expanded to attract suppliers from Indonesia, Malaysia, and eventually Australia. Japan is Australia's main LNG destination, followed by China and South Korea. In 2015, Australia's exports to these countries were 25.7, 7.3 and 2.5 bcm, respectively, accounting for 89 per cent of Australia's total LNG exports. This is shown in Table 5.

Table 5 Australia's LNG exports, by country, in billion cubic metres, 2003 to 2015

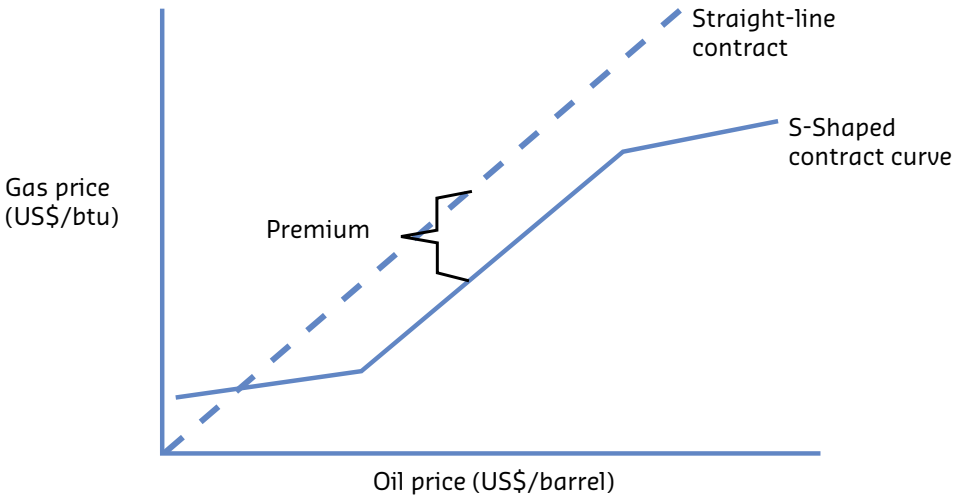
	Australian LNG importer													
Year	Middle East	Africa	China	India	Japan	Malaysia	Pakistan	Singapore	South Korea	Taiwan	Thailand	Europe	USA	Total
2003	-	-	-	-	10.27	-	-	-	0.17	-	-	0.08		10.52
2004	-	-	-	-	11.20	-	-	-	0.55	-	-	-	0.42	12.17
2005	-	-	-	0.16	13.05	-	-	-	1.16	0.40	-	0.08	-	14.85
2006	-	-	1.00	0.08	15.68	-	-	-	0.87	0.40	-	-		18.03
2007	-	-	3.30	-	16.05	-	-	-	0.56	0.33	-	-	-	20.24
2008	-	-	3.61	0.16	15.94	-	-	-	0.53	-	-	-		20.24
2009	0.08	-	4.75	1.12	15.87	-	-	-	1.75	0.60	-	0.08		24.25
2010	0.09	-	5.21	-	17.66	-	-	-	1.33	1.06	-	-		25.35
2011	0.30	-	5.00	0.20	19.00	-	-	-	1.10	0.40	-	-		26.00
2012	0.10	-	4.80	-	21.60	-	-	-	1.10	0.30	-	-		27.90
2013	0.10	-	4.80	-	24.40	-	-	-	0.80	0.10	-	-		30.20
2014	0.10	-	5.20	-	25.00	0.10	-	-	1.20	0.10	-	-		31.70
2015	0.74	0.09	7.24	1.16	25.69	0.43	0.27	0.99	2.55	0.33	0.27	-		39.77

Source: Authors' calculation from International Energy Agency and BP data.

In Asia Pacific, a typical long-term supply contract would tie the natural gas price to oil prices.

A typical long-term Asian LNG contract comprises three elements (Inchauspe, 2014). First, the contract specifies an oil price benchmark. The JCC crude oil price is the most common choice. Second, a price factor or slope is set in the contract. Considering that a btu (British thermal units) of natural gas has 16 per cent to 17 per cent of the energy content of a barrel of crude oil, a lower slope factor (for instance, 14%) implies that the buyer is paying a premium with respect to oil's equivalent calorific power. Third, different slopes that apply to different crude oil levels may be used to provide some protection to both the seller and the buyer. The combination of these three elements leads to the 'S-shaped' curve schematically represented in Figure 13.

Figure 13 S-shaped representation of a typical oil-indexed contract



Note: Asian LNG prices in long-term contracts are represented on the vertical axis, and compared to the JCC oil-equivalent price on the horizontal axis.
Source: Inchauspe (2014).

A study by the International Gas Union (2009) estimated average 'slope factors' from major bilateral LNG contracts signed in between 2000 and 2008, based on Netback Market Values (NMV) of LNG at specific locations. The JCC benchmark slope factor, representing the dashed-line calorific equivalence in Figure 8, was estimated at 17.4 per cent (this represents the dashed-line in Figure 8). Average slope factors for imported natural gas were as follows: Japan 8.8 per cent, Korea 11.5 per cent, Taiwan 4.8 per cent, India 11.9 per cent, and China 9.3 per cent. Importantly, all prices (except that for Taiwan) exhibited fairly consistent co-movements with approximately constant differences in slope factors, attributable to market conditions.

Japan's LNG price also moved at par with the Henry hub and European prices up to 2008-09, but has since surpassed both. This movement is attributable to several factors. The most relevant has to do with increased demand for LNG and the fact that Asian LNG importers compete for limited supply in the region. Although rampant energy demand growth from Asian importers was observable as early as in the late 1990s, it takes time for new margins to be observable in new long-term contracts (a typical long-term contract can last 5-20 years). Additionally, LNG importing infrastructure also requires time, and generally speaking, Asian importers have judged their infrastructure to be suboptimal in most years since 2000. Other factors, such as the post-Fukushima re-assessment of nuclear energy and stronger currencies in the aftermath of the 1997 financial crisis in South Asia, have contributed to high LNG demand growth.

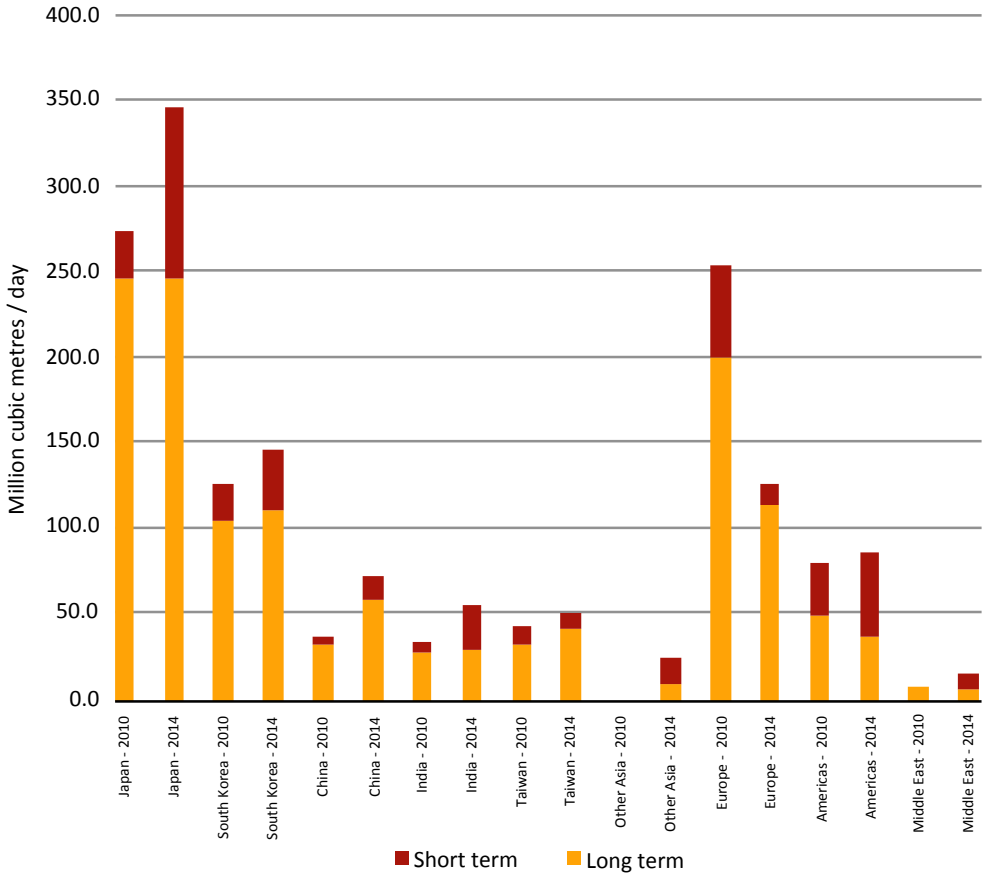
In recent years, Asian markets have started a transition towards spot pricing, with Singapore, Japan and China taking the initiative. As attested in Figure 14, the number of short-run contracts has increased substantially across all major Asian exporters between 2010 and 2014. Buyers in Asia are now demanding flexibility and new contracts, with new US suppliers offering it in two ways: by not including destination clauses in contracts, and setting tolling fees (penalties for missed deliveries) that are typically lower than that the take-or-pay clauses in traditional contracts. This process

could intensify soon with the advent of spot prices. In 2016, the Singapore Exchange launched the LNG price index SLLNG, which is essentially a financial instrument that is expected to reflect supply and demand forces from all over Asia. Australia's Global LNG Exchange (GLX), a Perth-conceived trading platform initiative, is expected to become fully operational in the first quarter of 2017[1].

Japan is also introducing flexible pricing through short-term contracts. Japanese are currently investing in regasification terminals and LNG storage facilities in the hope that by 2020 it will become a renowned international LNG trading hub. These developments seek elimination of destination restrictions that apply to the resale of cargo. In Japan's G7 meeting, Japanese authorities expressed support for the development of LNG trading hubs that improve market liquidity and transparency. They stated that in order to achieve this, LNG pricing based on market fundamentals, relaxation of destination clauses, continued negotiation amongst stakeholders and encouraged market developments are vital.

China launched the Shanghai Oil and Gas Exchange on 1 July 2015. It aims at providing a liquid platform for trading. To date, trade activities have not been significant but further participation is expected in the future.

Figure 14 Short- and long-term contracts, selected countries, in million cubic metres per day, 2010 and 2014



Source: Authors' calculation from US Energy Information Administration data.

1 http://www.glx-lng.com

After four years of sustained high gas and LNG prices of around $15 to $20 per mbtu, Asian oil-indexed and spot gas prices began to drop in the second half of 2014 due to the falling oil price combined with a gas and LNG glut in the region. Free on-board LNG prices in Asia have fallen to around $5 in 2016 – levels comparable to those in Europe. The price of gas in Japan dropped from around $9 in early 2016 to $7.50 by the middle of the year. The lower oil price environment means that gas-on-gas pricing, desired by some LNG consumers, does not necessarily deliver lower prices compared with oil-linked contracts. For example, US LNG contracts based off the HH benchmark have lost some of the price advantage they would have possessed prior to 2014.

In order for natural gas to develop its full potential in Asia Pacific it will be important to accomplish further gas-on-gas pricing reflecting demand-and-supply fundamentals on a global rather than regional scale. At the very least, some level of flexible pricing is desirable; this is because there is some trade-off between supply security and flexible pricing. Flexible pricing will enable natural gas to compete with the two other main contenders in the energy market, coal and renewables. It also unlocks supply of LNG from various regions of the world by eliminating inter-regional arbitrage opportunities.

A major disadvantage of gas-on-gas pricing for suppliers the risk of facing a low natural gas price that is triggered by low oil prices (although the converse could occur). It is nevertheless important to note that low oil prices are a problem that cannot, by definition, perpetuate in the long run. In oil-indexed gas contracts, parties can set any slope factor they want, so in principle, any natural gas price can be negotiated. However, these contracts are set for durations of up to 25 years, so a supplier may be locked in a low gas price situation for many years. The recent decrease in international oil prices took many gas producers by surprise, and some have in retrospect questioned their investment decisions. Given this situation, it is a concern that natural gas markets may never achieve their potential demand growth due to oil market related volatility.

On the other hand, flexible pricing might also be subject to substantial price risk. Given that all Asia Pacific markets are have well-connected fossil fuel markets at this stage, low prices in the natural gas industry could result from persistence of low prices on internationally traded coal and declining prices of solar collectors and other renewables (although it should be noted that natural gas generators are used as spinning reserves for wind power generation, so increases in wind energy supply lead to increases in natural gas demand). In this scenario, prices of natural gas may not cover costs including transportation and production.

Whether desirable or otherwise, the introduction of flexible pricing and supply arrangements will continue to gain adepts in Asia. In the medium run, the most likely outcome is a hybrid pricing mechanism in which both long-term contracts and flexibly-priced LNG will play a role. Asia's movement into a truly competitive hub with gas-on-gas pricing is well behind other regions. And, dependence on inflexible long-term contracts, which hinder the development of spot or futures trading in high-volumes, will not be completely eliminated any time soon. Despite efforts by a few Asian countries including Singapore, China and Japan to build and sustain trading platforms to act as benchmarks, both sellers and buyers that trade in these natural gas market remain sceptical regarding the feasibility of the pricing mechanisms available in the current market.

Australian LNG suppliers could seek strategies to diversify risks by offering both long-term oil-indexed and short-term gas-on-gas priced.

Evidence of prevalence of long-term contracts is provided in Table 6, which is consistent with Australian investors and clients having preference for secure, long-term, oil-indexed contracts. Many of these contracts will expire in 2020 to 2025. From this point forward, importers might not be interested in rigid long-term contracts anymore, and supply from the US and elsewhere might shift the negotiation power towards the importers. For Australia's firms to remain competitive, it will be important to closely follow the transition towards short-term or spot pricing and develop strategies to possible diversify supply – allowing for both a secure, long-term base, and more flexible supply. Therefore, Australian suppliers should consider the possibility of diversifying the risks associated with oil-indexation and flexible gas-on-gas prices by including both options in their portfolios.

Table 6 Long- and medium-run contracts for Australian LNG, in million cubic metres per day, 2002 to 2035

Loading point	Seller	Buyer	ACQ (Mtpa/day)	Duration	Type
Withnell Bay	Woodside, Shell, BHP Billiton, BP, Chevron, Japan, Australian ALNG Pty Ltd (Mitsubishi & Mitsui)	The Chugoko Electric	1.43	2009-2021	DES
		Tokyo Gas, Toho Gas	1.37	2004-2029	FOB
		Kyushu Electric	1.05	2009-2023	FOB
		Osaka Gas	1	2004-2033	FOB
		Tohoku Electric	1	2010-2019	DES
		Toho Gas	0.76	2009-2019	DES
		Chubu Electric	0.6	2009-2029	DES
		Tokyo Gas	0.5	2009-2024	DES
		The Kansai Electric	0.5-0.93	2009-2024	DES
		Chubu Electric	0.5	2009-2016	DES
		The Kansai Electric	0.2-0.44	2006-2021	DES
		Tokyo Electric	0.3	2009-2024	DES
		Kyushu Electric	0.18	2006-2021	DES
		Shizuoka Gas	0.13	2004-2029	FOB
		KOGAS	0.5	2003-2016	DES
		GDLNG	3.3	2006-2030	FOB
Darwin	ConocoPhillips, ENI, Santos, Inpex, TTSR	Tokyo Electric	2	2006-2022	FOB
		Tokyo Gas	1	2002-2022	FOB
Pluto	Pluto LNG	The Kansai Electric	1.75-2	2011-2025	FOB/DES
		Tokyo Gas	1.5	2011-2025	FOB/DES
Curtis Island	QCLNG	BG	Up to 8.5	2014-2034	FOB
	BG	CNOON	3.6	2014-2034	DES
	BG	Tokyo Gas	1.2	2015-2035	DES

Source: Authors' calculation from GIIGNL data.

LNG projects in Australia guarantee, in the medium run, a substantial amount of well-diversified supply. However, many of these contracts have been signed prior to the oil price collapse of 2014, and hence have been subject to cost-cutting and lower than expected profitability. With more than US$200 billion of new investment sunk into Australia's LNG projects, the industry may have survived its most critical point yet. By 2020 it is expected that Australia will have the largest LNG production capacity worldwide, overtaking Qatar. Nevertheless, challenges faced by early investors included project delays, cost overruns, stakeholder disputes in addition to an accumulating LNG surplus which has left investors sceptical about the future of

the industry. Recent weak price expectations have led new greenfield investment to a standstill in 2016/17. The relevant question for the industry will be how to sustain investment beyond 2020. At that point, both the market conditions and local supply chain might have very different characteristics. Once the industry is highly developed the new investment needed beyond 2020 will most likely take the form of brownfield investment along different components of the supply chain.

Chevron's massive Gorgon LNG project finally commenced production in March 2016 and appears to be the last in a long run of late LNG megaprojects. It ran one year behind schedule and 50 per cent over budget. Since this last mega-investment, buyers have indicated preference for US destination-flexible LNG over other suppliers. Gorgon, and other projects, have been forced to differentiate themselves through cost control and innovation. Chevron's head of operations in Australia, Roy Krzywosinski, openly stated during the LNG 18 Conference that if the company was to do it all over again it would have spent more time on 'front-end' work on the Gorgon megaproject ahead of final investment decisions on whether or not to proceed. Some other projects, such as Woodside's Browse project[2], have been cancelled.

As a cost-cutting innovation, major companies in Australia (and worldwide) are now looking at floating LNG (FLNG) offshore terminals as an option with great potential. After the 11.7 mt/year Browse project was abandoned off the coast of WA, Shell's 3.6 mt/year Prelude project, also based within the Browse Basin, will become the largest FLNG project once online. The abandoned WA project has placed some doubt in the minds of investors as to whether FLNG technology can live up to its potential in the early stages of development. To reduce engineering and construction costs, alterations to the original design for the Prelude FLNG project had been implemented. Now with potentially lower fixed sunk cost and improved flexibility to extract gas from relatively small reservoirs, FLNG projects have been able to accommodate exploration for gas reserves to feed into their current operating capacity.

Following the LNG 18 conference hosted in Perth, the LNG suppliers have remained hopeful on future prospects despite current weak demand and low oil and gas prices. But firms have also stated that LNG projects in Australia need to become increasingly cost-effective, in order to be able to compete with newer renewable energy technologies and fuels such as coal.

The Australian LNG industry has passed its most critical point yet, and will become the largest LNG exporter by 2020. The main issue is how brownfield investment can be accommodated beyond 2020.

2 The Browse basin project was officially abandoned on 22 March 2016, but new options are currently being considered (http://www.woodside.com.au/Our-Business/Developing/Browse).

LNG developments elsewhere

Australian LNG stakeholders should keep an eye on the rest of the world. Supply from Qatar, Russia and Africa has been so far contained, but could unleash in the future. South America might be a possible LNG destination in the short run, but has plenty of own long-run supply potential. Canada LNG exporting potential has so far not been realised.

Qatar is the world's largest LNG exporter and Qatar Petroleum is the most important firm in the global LNG export sector. However, Qatar will most likely maintain its self-imposed North Field moratorium until 2030. Introduced in 2015, this moratorium limits LNG output to 77 mbtu (104.7 bcm) per annum. To date, there has been no sign of lifting or altering this policy. Qatar's production costs are among the lowest in the world, and Qatar Petroleum is one of the few countries that have been able to sell at a profit during the low LNG prices period.

Sanctions, high production costs and political uncertainty have held back Russian LNG projects. The only LNG export facility that is likely to be operational by 2020 is Novatek's Yamal project, and another two (Sakhalin 2 and Baltic LNG) might become operational by 2025. Gazprom, the dominant pipeline gas firm, has shown little interest in LNG development.

In Canada, there has been no firm investment in LNG exporting infrastructure. Abundant gas resources are available in central Canada (Alberta), which is far away from potential liquefaction facilities on the west or east coast. Natural gas transportation through the Rocky Mountains to the west coast requires negotiation with indigenous communities that have proved difficult so far. In the east coast, natural gas is imported from the US, and low prices and regulatory hurdles have provided low incentive for LNG development. In other words, Canada could Canada could potentially be an LNG exporter at the level of Australia, but this is unlikely due to 'above-ground' constraints. Consequently, its potential is yet to be exploited.

LNG imports in South America started in 2008 and have been used as a mean to reduce supply dependency from Bolivia and Venezuela, and to negotiate lower prices. Argentina, Chile and Brazil are all LNG importers now, and LNG terminals are underway in Colombia and Uruguay. Argentina possesses vast shale gas resources in the Vaca Muerta region that were not exploited during presidents Kirchner's and Fernandez's administrations, but president Macri has announced this year a new program to attract foreign investors.

In the medium-term African LNG resources will remain largely untapped. For example, Nigeria's poor policy management has discouraged investment, and production is likely to remain stagnant until 2020. Among the most recent interesting developments, Perenco and Golar have developed a new floating LNG facility in Cameroon, which is expected to provide an additional 1.6 bcm per annum export capacity. Natural gas discoveries in East Africa (Tanzania and Mozambique) have also attracted investors, but these are seen as longer term LNG prospects.

International

trends in oil markets

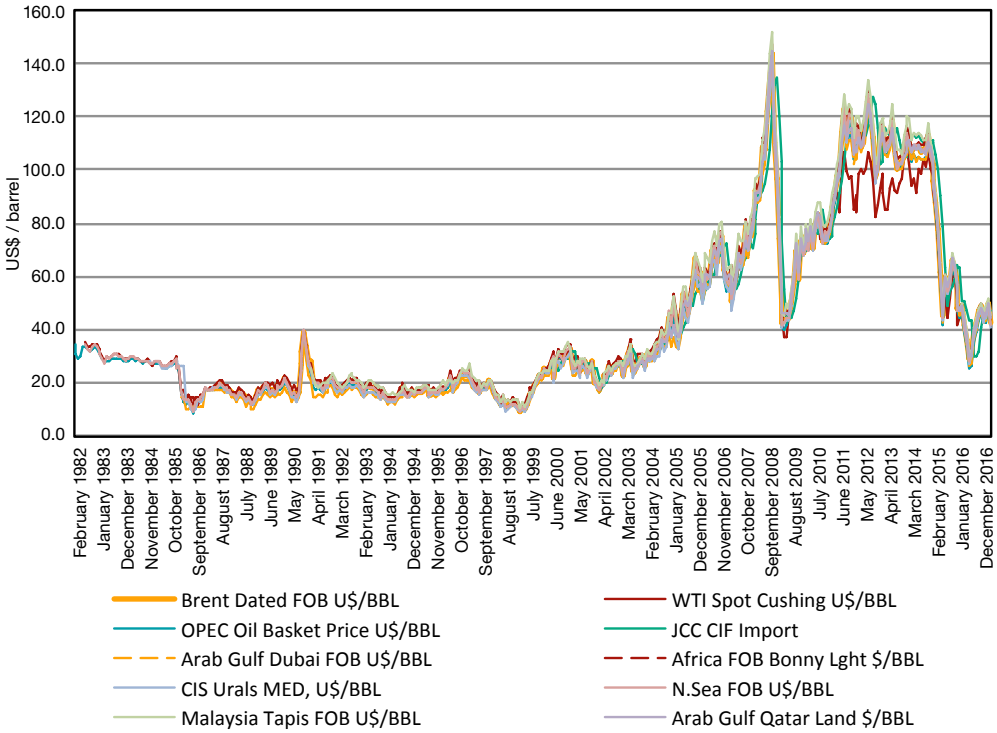
International trends in oil markets

In the previous chapter, it has been concluded that oil prices are – and will for some time still be – important for determining natural gas prices in Asia. It is hence important to review the international oil market in this chapter. We examine the main factors affecting the price of oil in both the short and long-run. We also review the composition of production and consumption, and the most significant trade flows. Because oil is not abundant in Australia – which means the country will continue to be a net importer in years to come – we do not focus on the role of Australia in international markets.

Oil prices

A feature that clearly stands out in Figure 15 is that, unlike gas prices, oil prices tend to move together. This is because oil markets have a much more integrated market than those of gas, and arbitrage opportunities tend to reduce or eliminate any price differentials. In this perspective, it makes sense to talk of a 'single' international oil market.

Figure 15 Main reference crude oil prices, in US dollars per barrel, reported in monthly frequency, 1982 to 2016



Source: Thomson Reuters DataStream.

For the most part, oil price differentials are explained by oil 'qualities' (density and sulphur content, TAN and API standards being the most important characteristics), which makes crude streams not always interchangeable as refinery inputs. An exception that stands out in Figure 15 is a short period in which the West Texas Intermediate (WTI) price, a major international reference, did not move in line with other oil prices. This was due to fast growing shale oil production combined with pipeline capacity constraints around the oil storage hub in Cushing, Oklahoma, which resulted in excessive oil stockpiles that could not be easily transported to refineries in the Gulf of Mexico. These issues pushed the WTI oil price down relative to Brent oil price. Following the resolution of the pipeline and distribution issues in the US, the WTI-Brent price spread started to contract from 2013 until it eventually reached the historical parity value once again. Similar experiences have occurred in other parts of the world, leading to significant discounts for some crude streams (e.g. the Western Canadian Select) relative to the prevalent benchmark prices.

A second salient feature in Figure 15 is that oil prices tend to be volatile and erratic. For instance, the WTI price was about US$30/barrel in 2001, US$140/barrel in 2008, US$90/barrel in 2009 and US$30/barrel in 2016, all expressed in real terms. Puzzling as this variation may seem to observers, it is not difficult to disentangle it with the aid of the fundamentals of oil markets, which includes some aspects that may be subtle or intrinsic and not necessarily well-understood.

Short- and long-run determinants of oil prices

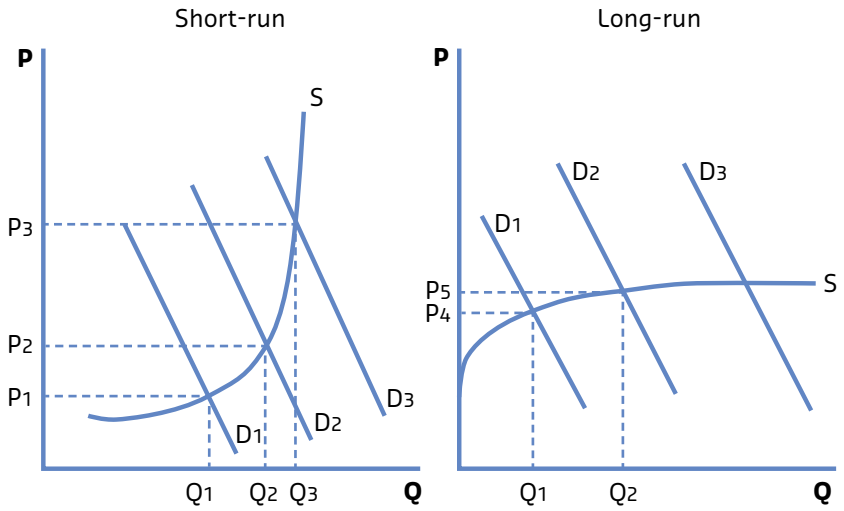
Oil demand and supply are highly inelastic, which means that small changes to production and consumption lead to large price changes, causing volatility.

This section builds on the work in Aguilera and Radetzki (2015), which at the time it was written (2014) had anticipated the current downfall of oil prices. According to the theories explored in this book, both short- and long-run variations in oil prices are determined by the market fundamentals, that is, forces that affect demand and supply of oil at a given price level.

What makes oil markets different is the relatively high inelasticity of demand and supply, a claim that is consistent with findings in economic academic journals. In economics, the term elasticity denotes a ratio of a percentage changes in two variables. The price elasticity of demand (supply) is the percentage change in quantity demanded (or supplied) resulting from a 1 per cent change in the price of the good. Inelastic demand (supply) means that changes to the oil price lead to very small changes in quantities demanded (or supplied). It also means that the demand and supply curves in Figure 16 are 'steep', and a small change that affects the quantity demanded (or supplied) at a given price, leads to great price variation, or price volatility.

The demand curve is relatively inelastic because there are very imperfect substitutes for oil utilisation in transportation and industrial oil-fuelled equipment. The supply is inelastic because, operationally, it is not easy to stop oil extraction, and investment in capacity to increase oil supply takes time to materialise. Typically, short-run, erratic price changes have to do with supply disruptions, taxes, announcements, and expectations. In the long-run, temporary disruptions become less important; it is the investment decisions and forces driving sustained demand growth that really matter. The recent technological developments allowing for growth in shale oil supply have been instrumental in increasing supply and expectations on further forthcoming supply growth. This, along with policy events affecting the composition of the energy mix, leads to low long run oil equilibrium price well below US$100/barrel and consistent with the right panel of Figure 16, according to Aguilera and Radetzki (2015).

Figure 16 Short- and long-run oil price determination



Note: Where P = price, Q = quantity and S = supply.
Source: Aguilera and Radetzki (2015).

Much of the short-to-medium run price variation observed in Figure 15 can be explained by specific events, most of which are supply disruptions. The following is a summary of some of the most significant oil market milestones:

- In 1974, OPEC announces an oil embargo on US, Canada, Japan, Holland and UK. Soon after, OPEC announces quotas limiting supply to increase oil prices and revenues. The reduction in supply has been estimated at 4.4 million barrels per day (Hamilton, 2012).
- In 1978, the Iranian Revolution takes place. Public demonstrations to overthrow the Iranian monarch leader lead to political turmoil which causes supply disruption and increases the oil price.
- In 1980, a new supply disruption takes place when Iraq declares war on Iran. Global oil production decreases by 6 per cent (Hamilton, 2012) and oil prices reach a historical peak.
- Between 1980 and 1986, peace and slower demand growth lead to low prices, despite several oil cuts being announced in 1982.
- In 1986, Saudi Arabia decides to abandon its pre-assigned quota and double its oil production, causing oil prices to hit a low.
- In 1990, Iraq invades Kuwait and the Persian Gulf War begins. Supply disruptions in the Middle East cause a new price spike.
- In 1997-98, the Asian Financial Crisis takes place. Speculative attacks on currencies of various South East Asian countries led to massive exchange-rate devaluations and output losses. Output losses spread globally and decreased oil demand caused oil prices to plummet.
- In December 2002, public demonstrations and political turmoil in Venezuela cause supply disruption.
- In 2003, the Second Persian Gulf War begins, this time with US and UK involvement.
- Between 2006 and 2008, galloping demand growth in Asia in combination with supply from major oil fields reaching maturity leads to the largest oil price spike yet.
- 2009 feels the repercussions of the global financial crisis on output and oil demand, and the oil prices reaches a low.
- In 2010, the Arab Spring begins. Political unrest in Iraq, Egypt, Libya, Tunisia and Yemen causes supply disruption that lead to a high-oil-price period that prolongs through to 2014-15.
- In 2015-16, the combination of appreciation of the US dollar (making oil more expensive to many countries, considering that international oil prices are denominated in US dollars), increased oil supply in the US and Middle East (including oil being freed up for export in Iran after the Nuclear Deal was signed), and moderately low oil demand growth in China and Asia, leads to low oil prices.

Oil prices exceeding the US$100/barrel level were not expected to prevail in the long run, and prices fluctuating around US$60 to $70/barrel seem a more realistic expectation for the next five years or so. Importantly, this expectation may fail to materialise in the presence of military or political conflict such as the above, which are in essence very difficult to predict. Additional sources of uncertainty at the moment are the possible trade restrictions – including tariffs, re-negotiation of trade agreements, and embargo situations – or conflicts that may arise in relation to the Trump administration in the US.

Future oil prices are difficult to predict. The current state of affairs and market conditions suggest that major oil prices should remain in the US$ 60-70/barrel level. However, history has demonstrated that at least one major supply disruption occurs in a decade.

Oil fundamentals: Demand, supply and trade

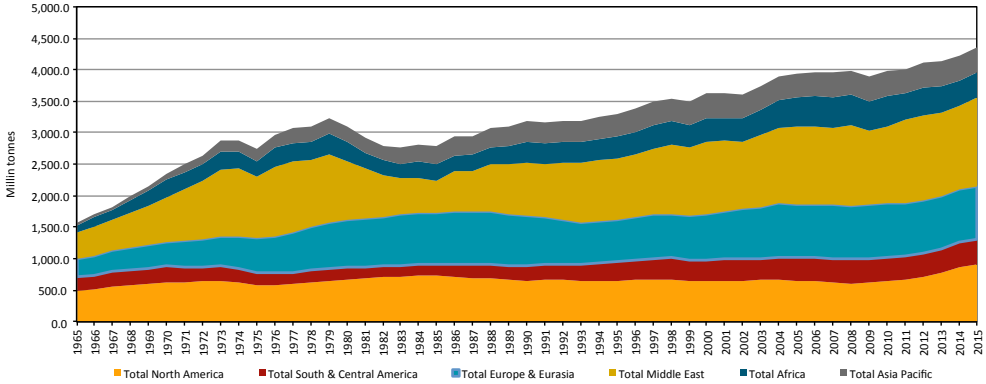
The oil market milestones described above can also be matched with Figures 17, 18 and 19. We leave the interpretation of these matches to the reader and focus on selected features.

Turning our attention to recent oil production, Figure 17 reveals that the increments in US production during 2010 to 2015 were approximately proportional to the increments observed in global supply. This increment can be explained by the production of US shale oil. We can also observe a smooth supply increase in the Middle East starting in 1991, although this increment, as a proportion of total supply, is much smaller.

A very recent driving factor that is expected to put downward pressure on oil prices and does not appear obvious in the analysis conducted above is the deconcentration of supply. To understand what is involved, it is crucial to review the instrumental role of OPEC's large oil producers in price formation. In 1960, Iran, Iraq, Kuwait, Saudi Arabia and Venezuela founded OPEC. A major objective of OPEC was to restrict output to indirectly raise the oil price and oil revenues. OPEC's official mission is 'to coordinate and unify the petroleum policies of its member countries and ensure the stabilisation of oil markets, in order to secure an efficient, economic and regular supply of petroleum to consumers, a steady income to producers, and a fair return on capital for those investing in the petroleum industry.' Essentially, OPEC has achieved its mission by allocating production quotas for its members, and alike coordination efforts.

An economic model thought as explicative of the emerging market structure is the so-called 'dominant-firm competitive-fringe model', which is reviewed in Dahl (2015). This model defines a large number of large producers who coordinate their actions through a cartel, and the remaining suppliers are classified as 'small'. In this context, a firm is said to be small if it cannot, alone, significantly affect the market price. In effect, small firms are 'price-takers' and make decisions on whether to supply and how much. On the other hand, large firms do have enough market power to affect the market price, and their joint profit – achievable as a cartel – is maximised when the level of output is relatively low. To do that, they act as if they were a monopolist facing excess demand, that is, the demand that is not met by small suppliers at given prices. It is then argued that, by trial and error, a cartel should theoretically find the profit-maximising amount of supply. This model has been questioned as it does not capture cartel instability, and alternative outcomes merging from quota negotiations or surpassing quotas. Nevertheless, its simple essential structure captures much of what has been observed in the market and could be used as a reference point. What is now changing is the amount of supply by small producers, or producers that are smaller than OPEC. As a result, OPEC's share of total supply (which matches the residual demand aforementioned, as a percentage of total demand) is being reduced. This residual demand reduction is restricting the profit possibilities for OPEC. Whatever supply arrangement is made within OPEC members, the profitability will not be as high as it would be in absence of the increase in non-OPEC supply. Hence, we could say that OPEC market power is expected to decrease over time, and that should put down pressure on oil prices. The additional non-OPEC supply is coming from relatively competitive suppliers and is linked to shale oil developments. The US is currently at the forefront, and some of its shale oil well projects are now maturing, but further greenfield development of competitive shale supply is expected in the US and elsewhere, where shale oil has not yet being developed.

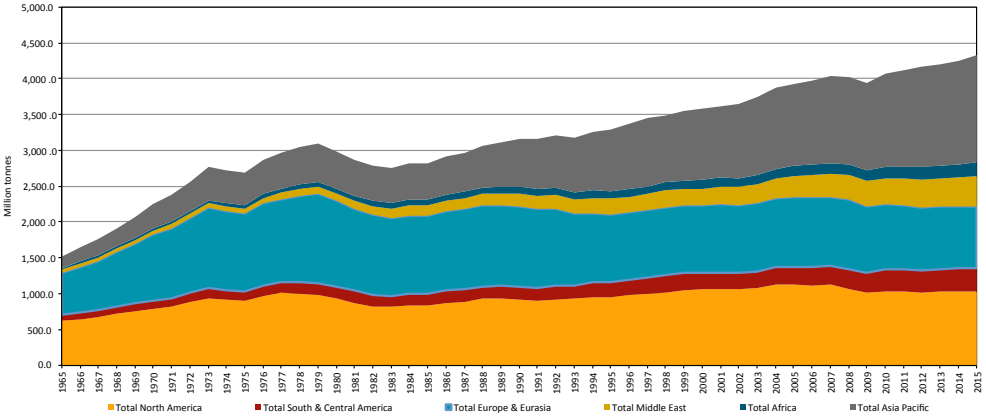
Figure 17 Global oil production, in million tonnes, 1965 to 2015



Source: Authors' calculation from International Energy Agency data.

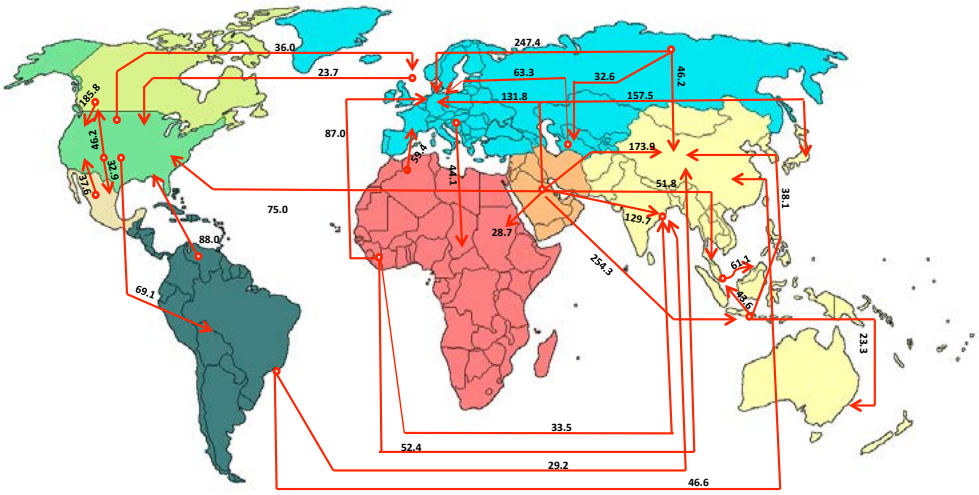
When it comes to oil consumption, it is not surprising to see again that most of its growth, from around 1990, originated in Asia Pacific. The rapid rise in income in emerging Asian economies has increased demand for transportation, and oil has also been used intensively in industrial production. The consumption in Europe and Eurasia has declined in the last decade, mainly due to energy efficiency measures and declining population. In North America, oil consumption is also in decline. Figure 19 proves that oil consumed in Asia comes from almost all parts of the world, except North America. Figure 19 also demonstrates that there are important trading hubs. These give rise to the reference prices in Figure 15. In Asia, trading activities are intensive in China, Malaysia, India, Indonesia and Japan.

Figure 18 Global oil consumption, in million tonnes, 1965 to 2015



Source: Authors' calculation from International Energy Agency data.

Figure 19 Main global oil trade flows in 2015, in million tonnes



Source: Authors' calculation from International Energy Agency and BP data.

Oil spot and futures prices

An important characteristic of oil markets is that oil traders can use futures contracts to hedge against the risk of price fluctuations. Oil futures are mainly used for hedging, and only about one per cent of futures contracts lead to physical delivery of the commodity. We argue that if liquid trade at the new Singapore Exchange LNG hub – and possible other hubs in Asia – progresses, natural gas futures could likewise be used as hedging instruments in Asian LNG markets, and lessons from experiences with oil and other commodities would be valuable for that endeavour.

A 'futures contract' generally refers to a legal contractual agreement whereby the contract buyer agrees to take delivery from the seller, of a specific quantity of a good at a predetermined price and at a specified time in the future. In oil futures markets both buyers and sellers of crude oil can benefit from such arrangements. Crude oil producers can sell crude oil futures ('go short') to lock in a selling price for the crude oil they produce. On the other hand, crude oil consumers can buy oil futures ('go long') to secure a purchase price. Although some futures contracts call for actual physical delivery of the crude oil, others are settled in cash. The main crude oil futures exchanges are the New York Mercantile Exchange (NYMEX) and the Intercontinental Exchange (ICE), where West Texas Intermediate (WTI) and North Sea Brent crude oil futures are respectively traded.

Futures contracts are a very important instrument for hedging price risk variation in oil markets, and might play an important role in liquid gas-on-gas trading hubs in Asia, should they develop.

Recently, analysts have debated whether the WTI or Brent prices should be used as a global hedging benchmark. Addressing this debate, Burns, Inchauspe and Ripple (2017) have studied hedging mechanisms for the pricing method used by Saudi exporters. Historically, Saudi oil exports were priced according to the destination of the volume flows. For volumes flowing to North America, Saudi oil exports were priced against the WTI spot price. For volumes flowing to Europe, oil exports were priced against the Brent spot price. Lastly, for volumes flowing to Asia, Saudi oil exports were priced as a 50 per cent, 50 per cent weighted average of Oman and Dubai spot oil prices.

A radical change occurred in 2010 when Saudi oil exports to the US started to be priced against the Argus Sour Crude Index (ASCI). The ASCI is the volume-weighted average of the prices of three crude oil grades traded in the Gulf of Mexico hub (Mars, Poseidon and Southern Green Canyon). This change relates to the US demand management issues described above, affecting the WTI price. Although there are no futures contracts on Saudi crude oil, there are futures contracts related to the Brent and WTI spot price that could be used for hedging. Therefore, an importer of Saudi oil residing in North America or Europe could effectively hedge using those in a portfolio. Burns, Inchauspe and Ripple (2017) construct various portfolios using near-month futures contract and arrive at two important conclusions. First, when hedging against the WTI or Brent price, the local futures contract (i.e. the WTI futures contract for WTI spot price, and Brent futures contract for Brent spot prices) is the more effective hedging instrument. Second, when hedging against movements in the ASCI spot price, a two futures portfolio is more effective than a single futures hedging portfolio. However, which futures contract dominates the ASCI hedging portfolio is influenced by a range of factors and does change over time, and the Brent futures contract was indeed more important when the WTI price derailed.

Recent

technological developments

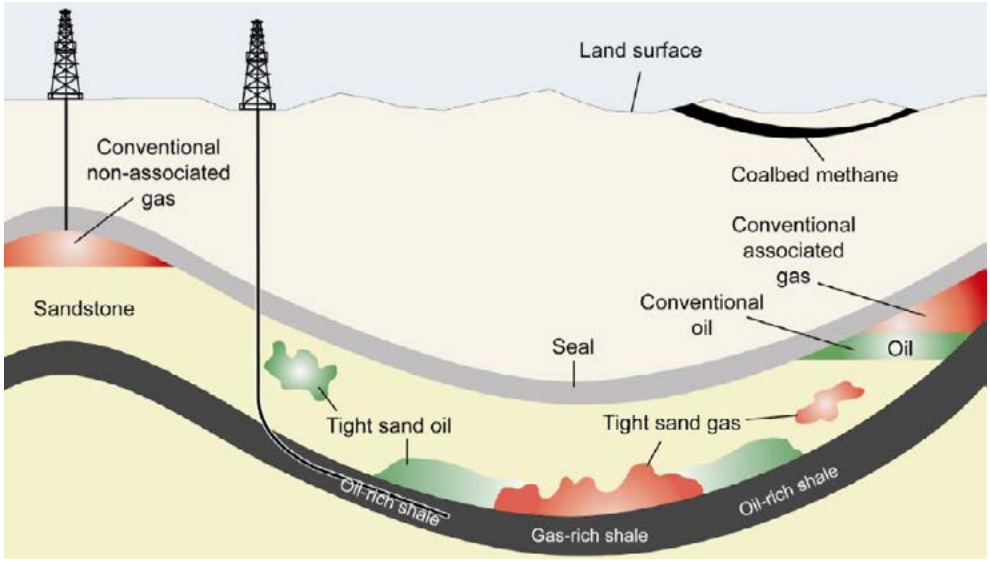
Recent technological developments

Previous chapters covered the implications of increased supply of unconventional gas and oil. To complement them and make this study self-contained and compact, this chapter offers some coverage of key technologies. We review the technologies for recovering unconventional gas and oil and assess the world's and Australia's potential. In addition, we cover developments in floating LNG facilities, a new technology that will be key in future LNG markets. We include a brief summary of the lessons learned from Australia's LNG ventures over the past decade.

Unconventional oil and gas

In recent years, technological improvements made the development of unconventional natural gas resources economically viable. The recent technological developments include the combination of hydraulic fracturing with horizontal drilling, which is useful for developing resources deep underground such as tight gas and oil (depths greater than 1,000 meters) and shale gas and oil (depths between 2,000-8,000 meters). Figure 20 summarises the different types of oil and gas resources. As observed, natural gas may be 'associated' (with oil) or not. Figure 20 also identifies 'conventional' resources, which technically speaking are those that exist in well-defined reservoirs with permeability levels higher than defined standards. Typically, conventional oil and gas lie within 1,500 metres from ground level and are extracted with vertical wells. Unconventional natural gas is classified as (i) coal bed methane (CBM) or coal seam gas, (ii) tight gas and (iii) shale gas. Tight gas is found in various low-permeability sandstone and limestone reservoirs, whereas shale gas is found in continuous rock formations known as shales. CBM is found in shallower coal seams (300-1,000 meters) and its extraction does not generally require horizontal drilling. In a typical CBM development, about half of the wells require hydraulic fracturing. A comparative advantage of CBM is that it contains very little heavier hydrocarbons and no gas condensate[3]. Exploration of shale and tight resources is generally difficult, and the recovery rates are generally lower than those of conventional wells. However, technological development has reduced costs significantly, and now a great part of these resources has become economically exploitable, expanding reserves globally (Chapter 1).

Figure 20 Conventional, tight and shale oil and gas



Source: Modified from US Energy Information Administration and US Geological Survey.

3 The primary chemical component of natural gas is methane, which is formed by four atoms of hydrogen and one of carbon (H_4C). Natural gas can also have heavier components, including: ethane (H_2C_6), propane (H_3C_8) and butane (H_4C_{10}). The term 'wet gas' is used to refer to gas in raw state, while 'dry gas' refers to processed gas in which heavy components have been removed.

Hydraulic fracturing and horizontal drilling are old extraction techniques, but it was the combination of the two that made a breakthrough when the shale revolution started about ten years ago. The combination of these two techniques is often referred to as 'fracking', and as we explained is used for extracting shale oil/gas and tight oil/gas. Essentially, fracking is a well stimulation technique. In a typical shale well, a wellbore penetrates the ground vertically until the shale is reached. Then, the wellbore turns horizontally, as shown in Figure 20. It may split into more than one borehole. Along the horizontal borehole(s), lateral injections of highly-pressurised 'fracking fluid' crack the rocks to release the oil or gas. The fluid formulas used in shale wells are not always known to the public, but usually consist of water with small grains of a proppant (quartz sand, silica or aluminium oxide), thickening agents, lubricants, corrosion inhibitors, biocides and clay stabilisers.

Fracking safety is a sensitive topic, and it would be in the interest of everyone in Australia to conduct an independent assessment and educational campaign.

When fracking first started in the US, there was general public concern about the possibility of environmental damage, including earthquakes, water and ground pollution. Now that more than 20,000 wells have been developed worldwide, the evidence suggests that fracking is generally very safe. In 2010, producers' violations at the Marcellus Shale (Pennsylvania, US) that involved thin cementing and inappropriate casing caused fracking fluid filtrations, contamination, and some public debate. Regulations have since strengthened to avoid such failures. From this experience, it is worth remarking that it was the cement casing, and not the fracking extraction process, that was responsible for contamination. Still, fracking may be associated with some negatives, factors, including the vast amounts of treated water injected into the ground, landscape contamination, and other sorts of contamination that to a large extent are preventable with proper regulation. While it is not within the scope of this report to assess these factors, we remark that it would be in the interest of stakeholders involved in discussions to have access to more comprehensive, accurate, accessible independent research assessments for Australia. Despite some prior investigation into the subject, the Australian government could continue to produce independent research on the issue to educate stakeholders according to the findings.

The US shale revolution is the result of years of research and government support.

It is worth remarking that the fracking breakthrough in the US was not a mere coincidence. Through mixed public-private initiatives, including tax incentives, and R&D support, the US government has been active in supporting technological innovation in the sector since the 1970s. Estimates of government support to the US CBM industry are provided in MIT (2011, p. 163).

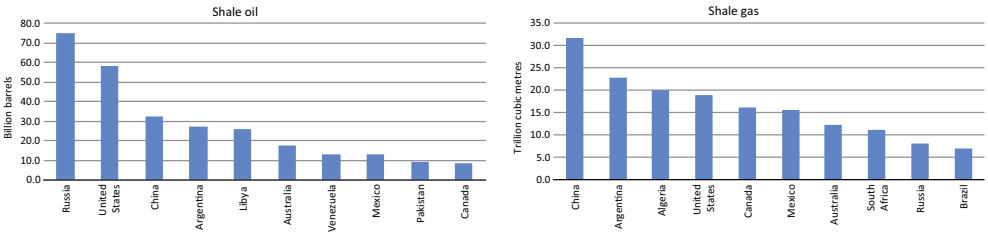
Assessing unconventional resource endowments

A major effort to compile shale geological data from best available sources was commissioned by the US Energy Information Administration and published in 2013. Since its first publication, it has been regularly updated, and the latest available revision is available through EIA (2015). Data for Australia has been compiled from government geological surveys (from Geoscience Australia) and industry data. Processing this data leads to some interesting findings for Australia.

To understand how the shale revolution has affected supply from a global perspective we list the top countries in Figure 21 according to their technically recoverable (that is, proven and unproven resources that are economically exploitable) resource endowment. Australia ranks number seven in shale gas, and it becomes the highest ranked in terms of per capita shale gas endowment. However, the absolute country endowment and its dispersion do not contribute to economies of scale, and from this angle, Australia may not be the most favoured nation. When it comes to shale oil resources, Australia ranks sixth in the world, according to the EIA assessment.

Australia has the highest per capita endowment of technically recoverable shale gas in the world.

Figure 21 Top 10 countries with technically recoverable shale oil and gas



Source: Authors' calculation from US Energy Information Administration data.

Table 7 Shale resources in Australia

Basin	Formation	Shale gas		Shale oil	
		Risked in-place (bcm)	Technically recoverable (bcm)	Risked in-place (billion barrels)	Technically recoverable (billion barrels)
Cooper	Roseneath-Epsilon-Murteree (Nappamerri)	8,702	2,528	17	1.0
	Roseneath-Epsilon-Murteree (Patchawarra)	484	102	9	0.4
	Roseneath-Epsilon-Murteree (Tenappera)	34	3	3	0.1
Maryborough	Goodwood/Cherwell Mudstone	1,810	543	0	0.0
Perth	Carynginia	3,515	703	0	0.0
	Kockatea	1,236	223	14	0.5
Canning	Goldwyer	34,750	6,666	244	9.7
Georgina	L. Arthur Shale (Dulcie Trough)	1,151	230	3	0.1
	L. Arthur Shale (Toko Trough)	751	132	22	0.9
Beetaloo	M. Velkerri Shale	2,671	627	28	1.4
	L. Kyalla Shale	1,758	400	27	1.3

Source: Authors' calculation from US Energy Information Administration data.

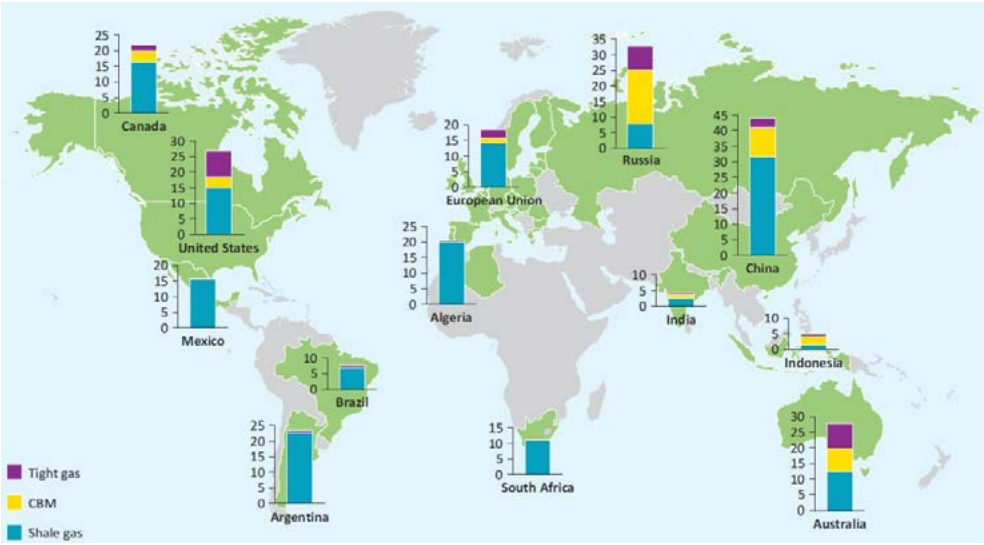
A comparative advantage of Australia for technological development and risk diversification is that it possesses all main types of natural gas.

A comparative advantage of Australia is that it has not only conventional gas, but also shale gas, CBM and tight gas, as demonstrated in Figures 22 and 23. This unique endowment has advantages for sharing know-how, developing new technologies and investment risk diversification by developing both small and large projects. The geographic distribution of each resource type is interesting. Much of the recoverable shale gas is located in Western Australia, in the Canning and Perth basins (Table 7). WA also possesses the largest endowment of conventional reservoirs, but there are significant pipeline and other infrastructure problems. Coal bed methane is most abundant in Queensland and New South Wales, but sizeable endowments are also found in Northern Territory, Victoria, and South Australia. CBM commercial extraction in Australia started in the Bowen basin, Queensland, in 1996. Today, nearly 80 per cent of total natural gas production in Queensland is in the form of CBM. The main CBM deposits in Queensland are the Surat and Bowen basins. According to IEA (2013), the production of CBM natural gas in Australia will have grown by approximately 90 per cent by 2035. When it comes to tight gas, substantial projects are under way. Australia's largest tight gas deposits include the Perth basin (WA), Cooper basin (South Australia/Queensland) and Gippsland basin (Victoria, offshore). Investment in Australia generally prioritises CBM and tight gas, in addition to conventional gas, as developing shale gas is more expensive to explore and extract and requires large-scale investment. CBM is usually developed at a smaller scale than tight gas in Australia.

Strong regulations in NSW have put a freeze on new CBM developments.

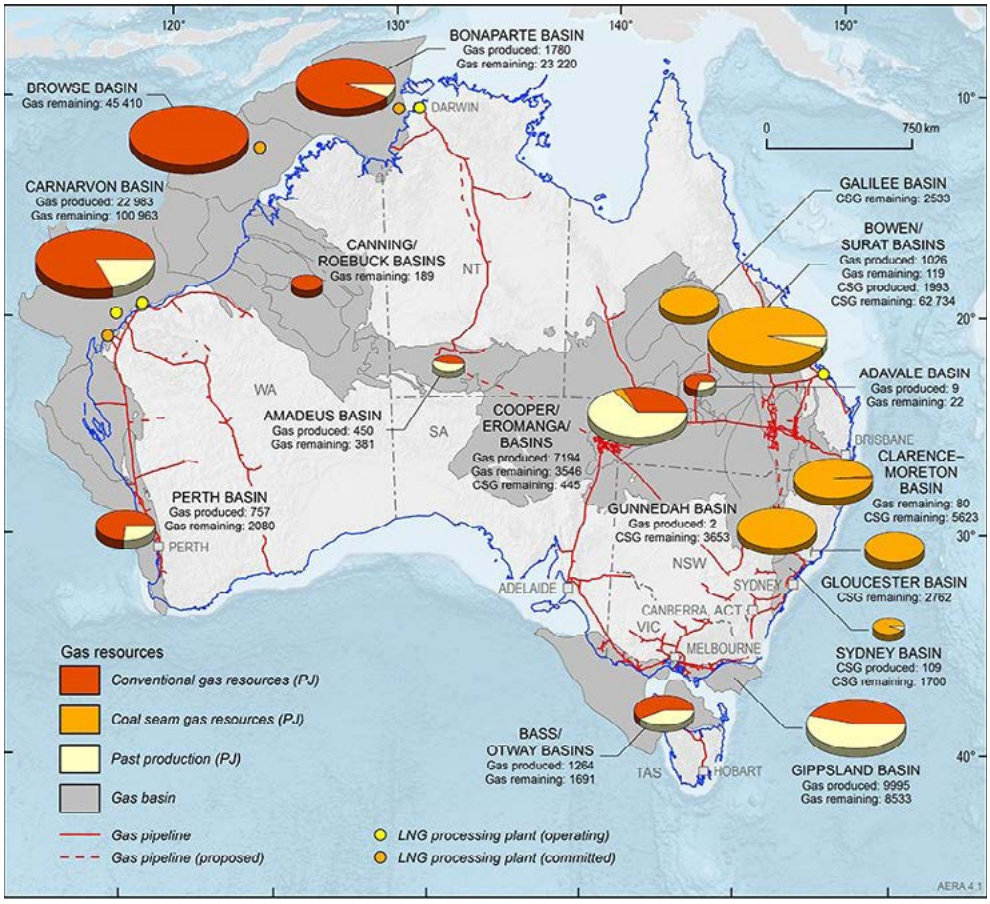
In terms of natural gas regulation, NSW is by far the most restricted state in Australia. CBM is abundant, and in the past many licences were granted. By now, most wells have been permanently sealed and only a handful of firms develop CBM. The most significant state regulation was announced on 19 February 2013. The NSW government placed a moratorium on new developments, i.e. a freeze on new licences. It also prohibits developments in CBM restricted zones, which are zones within 2 kilometres of residential areas and critical industry clusters. The policy is generally supported in rural areas that suffered from landscape contamination, which could perhaps have been avoided with tougher activity regulation in place. There is no indication that NSW authorities will completely lift the ban any time soon. If it does happen far in the future, e.g. as a result of NSW lagging economically in relation to other states, there might be a substantial economic benefit.

Figure 22 Conventional, tight and shale oil and gas



Source: International Energy Agency.

Figure 23 Coal bed and conventional gas in Australia



Source: Geoscience Australia.

Given the cost blowouts and delays that become commonplace in the development of Australia's mega-LNG projects, Deloitte (2016) collected responses from major players about lessons learned for the future. One message that emerges forcefully is the need for producers to collaborate in terms of technology and innovation. For instance, the recent practice of developing many projects simultaneously, but without collaboration, led to excessive infrastructure. Facilities could have been shared, or standardised, leading to substantial cost savings. Furthermore, it would have been beneficial to use brownfields and infrastructure already in place. Most gas and LNG executives have acknowledged that areas for companies to work on include more efficient design, engineering and construction, and improved productivity in general across the supply chain.

Floating LNG (FLNG) terminals and vessels

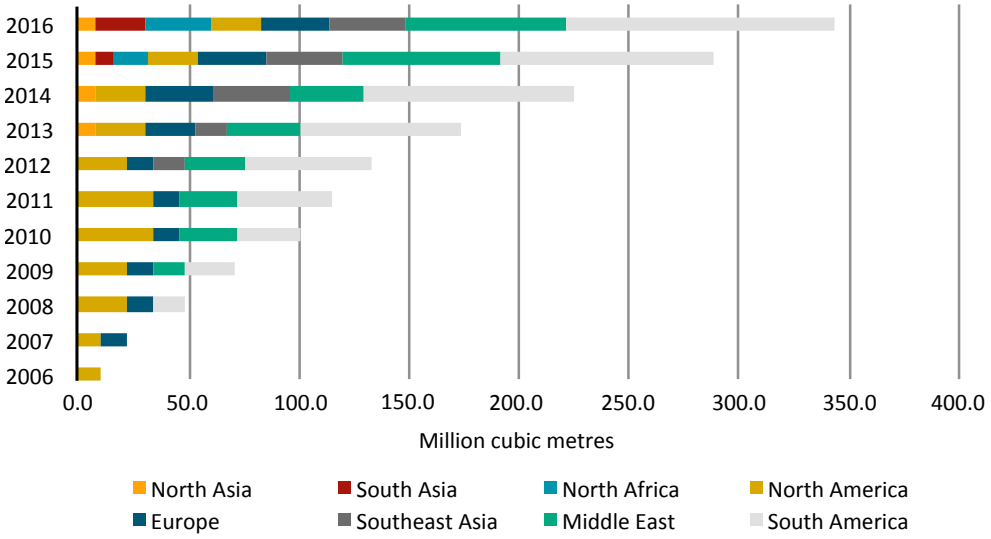
The most recent breakthroughs for gas markets are associated with floating LNG (FLNG) technology. Although floating terminals are becoming popular now, they are the result of years of research. In the last decade 18 LNG storage and regasification units have been installed, and one floating liquefaction facility is under way. Furthermore, Texas-based Excelerate and Norway's Hoeg are expected to soon introduce cargo vessels capable of liquefying LNG.

Floating LNG terminals for importing gas are now proving to be highly beneficial for gas consumers, gas suppliers, and terminal builders. From a gas consumer's perspective, a key advantage of floating units is that they can be built at a much faster pace than traditional onshore terminals. In Egypt, for instance, two storage and regasification units – which would take few years to build onshore – became operational within a few months. Likewise, recent supply shortages in Latin America were addressed relatively quickly with floating technology. Financially, floating LNG terminals are also attractive, because it helps avoid long periods of sunk, immobilised capital. For both LNG consumers and terminal builders, an additional benefit of FLNG terminals is that they do not have to be tied to any particular distribution company or network. Floating units can be leased, and companies such as Golar LNG and Exmar specialise in this area. Lease units are designed for re-use and modification. From a buyer's perspective, the main advantage has been the opportunities to allocate supply overhangs. Although there is little experience on this front, floating LNG terminals can be used in principle as a trading hub for buying and selling gas. Below, in Figures 24 and 25, we present data on floating LNG additions. What stands out is that countries that were not part of the LNG markets in South America, Africa and the Middle East, have now become FLNG buyers.

We thin cargo ships with re-gasification capacity have the potential to be a 'game changer' for the Australian LNG industry, so we recommend that companies and policy makers look seriously into it.

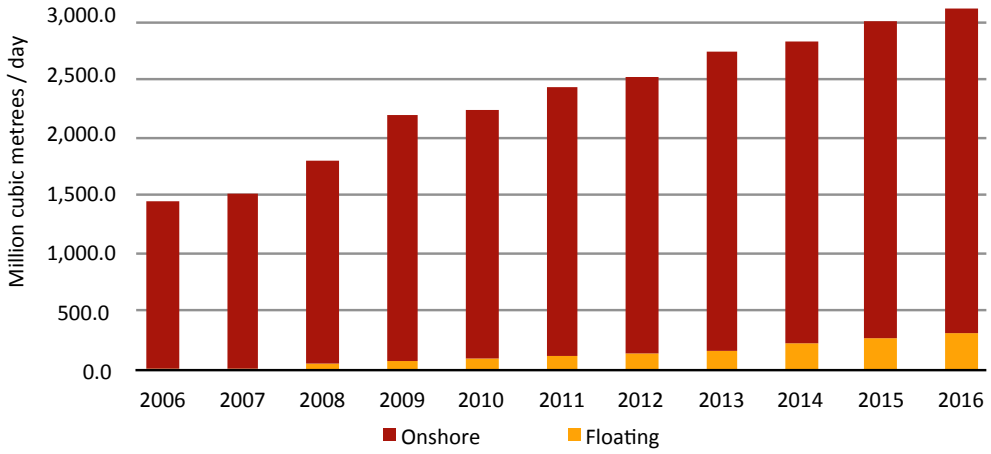
An interesting finding is the possibility of developing fully-mobile ships capable of re-gasifying LNG. Now that Australia is maturing and preparing for a post-2020 scenario in which gas-on-gas pricing may be preferred in Asia Pacific, FLNG terminals at the receiving end can open a whole spectrum of spot or short-term trade possibilities. For Australian suppliers, it might even be worth considering acquiring some ships of their own. One ship with regasification capacity could be acquired for about US$300 million (Financial Times, 2017). In possession of it, an Australian firm would be able to reach international destinations with no-regasification terminals onshore and gain market power to choose among the best paid deliveries in international markets. It could potentially be a 'market-maker' instrument. New contracts could even be reached through new pricing mechanisms, such as an Australia-based auction environment. If the scale of Australian projects does not allow firms to afford re-gasification vessels, firms could consider joint ventures and sharing schemes. Alternatively, or in addition, the Australian government could also consider public-private agreements to help firms gain access to such ships. All in all, floating LNG technologies have the potential to be a 'game changer' for the Australian LNG industry, and we would recommend to Australian firms and policy makers to assess the prospects.

Figure 24 Floating LNG capacity additions, in million cubic metres, 2006 to 2016



Source: Authors' calculation from Thomson Reuters DataStream.

Figure 25 Onshore versus floating LNG regasification capacity, 2006 to 2016



Source: Authors' calculation from US Energy Information Administration data.

Australia's

position

Australia's position

In this final chapter, we investigate key questions building on the findings presented so far. At the start of this report it was argued that the rapid expansion of LNG was due to the conjunction of high demand from China, high oil prices and the Fukujima nuclear crisis. Now, we will analyse the demand prospects in a first section. A second section will then provide some forward vision for the Australian industry.

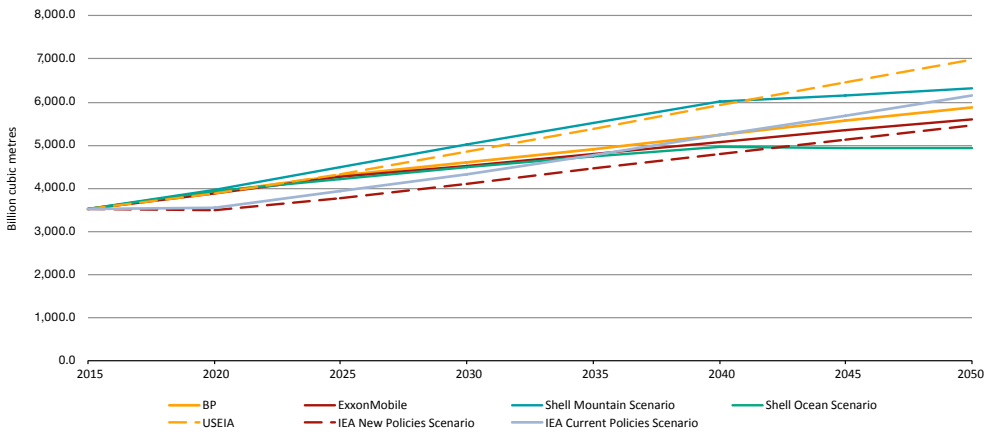
As for the third and final section, there is a special focus. So far, this report has so far not discussed many important topics, such as technical regulatory issues, environmental policy, electricity market issues, taxation, and so on. We are not providing exhaustive coverage of these topics because doing that would make the study excessively long, and there are existing guiding documents for that (unfortunately, this information is not available from a single source). What we do in our final section is assume that the reader is generally familiar with the topics, so we can focus our attention on selected policy dilemmas. Seven policy fronts are covered.

Demand's prospects

Aguilera, Inchauspe and Ripple (2014) analyse whether the Asia Pacific region is large enough to accommodate all suppliers. The study builds on the knowledge of international industry and government experts who have been preparing long-term energy forecasts, usually with a time period of 20 to 40 years into the future. Some oil and gas multinationals (such as BP, Shell, Exxon, and Statoil), non-for-profit organisations (e.g. International Gas Union, the Massachusetts Institute of Technology, and Oxford University) and governmental organisations (e.g. US Energy Information Administration, and OECD's International Energy Agency) prepare detailed forecasts with horizons between 2030 and 2050. The predictions are based on models that include all energy types in the mix, all regions (countries) in the world, and make key assumptions regarding policies, income growth, population growth, energy market structures. Importantly, these studies are updated, and by using them we can benefit from the knowledge of expert forecasters that have deep understanding of the industry. The approach taken in Aguilera, Inchauspe and Ripple (2014) consisted of building an average consensual forecast from selected sources. It is a procedure that has proven to improve forecasting power, as the prediction results from combining forecasts usually outperforms combinations made from subsets of forecasts (Baumeister & Kilian, 2015). The paper then performed some sensitivity analysis. The consensual natural gas additional demand and supply for Asia Pacific in 2030 were estimated at 41.5 tcf (1,162 bcm) and 29.3 tcf (821 bcm), respectively, meaning that approximately 70 per cent of Asia Pacific demand would be met with indigenous supply. Sensitivity analysis considering the highest and lowest regional supply estimates available led to the conclusion that gas demand in Asia Pacific was sufficiently large to accommodate all suppliers. Now that Russia and Qatar have increased their LNG injections into Asia Pacific, and knowing that pipeline trade between Asia and other regions has evolved rather slowly, there is a need to revisit the demand and supply balance in Asia.

To confirm the validity of the above results in today's world we consulted the same and alternative sources, essentially verifying that the same long-run demand trend holds. Based on the forecasted global demand by various organisations (Figure 26), we find that an additional demand in Asia Pacific of extra 1,162 bcm is within expectations.

Figure 26 **Forecasted world natural gas demand by various sources, measured in bcm, 2015 to 2050**



Note: Mismatching horizons where matched with linear extrapolations.
Source: Authors' calculation from BP, Shell, ExxonMobile, US Energy Information Administration and International Energy Agency data.

Expectations on environmental policies stemming from the recent Paris Agreement have also played an important role in our optimistic outlook for gas. Following COP21, several energy companies have signalled an aim of shifting their fuel portfolios towards natural gas, the cleanest fuel of all. The increasing importance of gas, as we explained, was mainly initiated by fuel switching from coal to gas in China. So far, economic growth in the region has mostly been fuelled by coal and to a lesser extent oil, but now all major reports predict further fuel substitution.

Energy demand from smaller gas-consuming countries in Asia is now perceived more favourably in international reports. In addition to rising consumption over the long-term in the traditionally important gas and LNG costumers, which include China, Japan and South Korea, demand is now expected to rise sharply in nations like India, Indonesia, Malaysia, Singapore, Thailand and Vietnam.

Long-run demand prospects for both natural gas and LNG in Asia look strong.

Having analysed demand trends in Asia, we now focus on LNG. The main problem with Figure 26, which most of the forecasts are based on, is that consumption (as well as production) patterns are predicted with no specific trade flows. What's more, in most cases we do not even know the proportion of demand that will be supplied with LNG. To address this issue, we borrow LNG sensitivity analysis conducted for the Oxford Institute of Energy Studies by Honore *et al*. (2016). According to the authors, the key factors affecting uncertainty in each scenario are future pricing schemes, energy mix developments, domestic supply and regulated prices.

Table 8 LNG demand scenarios, in million tonnes per year, 2010 to 2030

	Low case (million tonnes)					High case (million tonnes)				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Japan	70.9	85.1	63.3	63.6	59.3	70.9	85.1	91.7	91.7	88.4
South Korea	32.7	33.4	32.9	33.7	34.9	32.7	33.4	34.5	36.5	38.7
Taiwan	11.2	14.5	14.9	15.9	16.8	11.2	14.5	16.5	19.7	23.6
China	9.6	20.0	39.7	33.8	55.1	9.6	20.0	58.1	48.5	77.2
India	9.0	14.6	22.1	36.8	48.5	9.0	14.6	26.5	44.1	58.2
Singapore	-	2.1	4.8	7.9	10.1	-	2.1	5.1	8.4	10.9
Thailand	-	2.7	8.1	15.0	16.5	-	2.7	10.2	19.7	22.9
Indonesia	-	-	-	-	6.9	-	-	-	3.6	15.3
Malaysia	-	1.5	2.8	3.7	4.6	-	1.5	2.8	3.7	7.9
Pakistan	-	1.0	7.4	10.3	10.3	-	1.0	8.8	11.8	19.1
Bangladesh	-	-	2.9	5.9	13.2	-	-	4.4	11.8	19.1
Vietnam	-	-	-	3.2	6.7	-	-	-	4.2	8.4
Total	**133.3**	**174.9**	**198.8**	**229.6**	**283.0**	**133.3**	**174.9**	**258.5**	**303.6**	**389.8**

Notes: 1 million tonnes LNG = 1.38 billion cubic meters NG.
Source: Authors' calculations from Honore *et al.* (2016).

Focus on China and India

The main conclusion from the last section is that there will be plenty of long-term demand in Asia Pacific. However, there are questions on whether there will be enough LNG re-gasification capacity and, if there is, it is not clear that there will exist new adequate infrastructure to carry the natural gas to final consumption destination points. The main problem in India, and to a lesser extent China, is that natural gas flows to the shores or hubs but cannot reach many users outside major urban agglomerates or industrial hubs.

Luckily for Australia, China has committed to heavy investment in LNG import infrastructure (Table 9). Roughly 30 per cent of under way LNG re-gasification infrastructure in the world is located in China. These developments are strongly pushed by Chinese government authorities seeking supply diversification from Turkmenistan, supply security, and further from coal-to-gas substitution.

It is noteworthy that China and India, our prominent costumers, have a relatively small shares of natural gas consumption in their primary energy mixes at present. Thus, there is ample opportunity for gas to capture market share in the future. Some of the factors underpinning the optimistic gas outlook in Asia are the brisk economic expansion of the region, which will remain in an energy intensive mode for the foreseeable future, and the abundance of natural gas around the world and the expanding LNG and pipeline trade over the long-term.

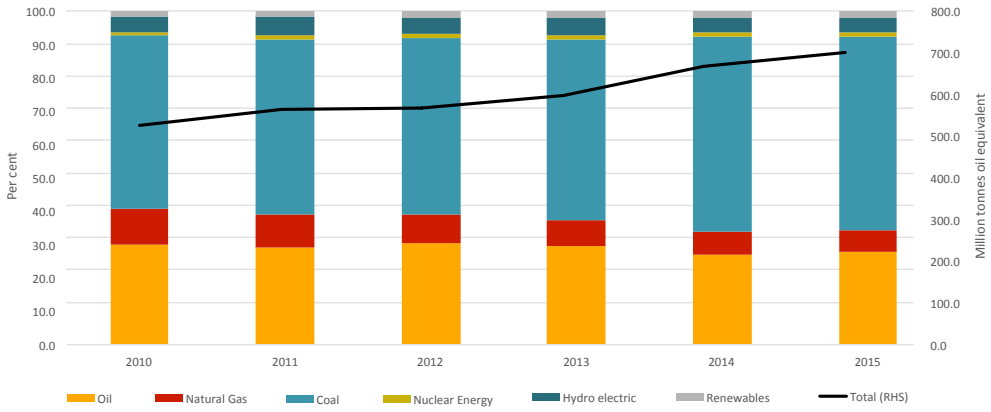
Table 9 LNG import facilities under way (as of October 2016)

Country	Project	Capacity (bcm/y)	Major participants	Start up
China	Diefu LNG	5.4	CNOOC, Shenzhen Energy	2016
China	Guangdong Dapeng LNG Expansion	3.1	CNOOC, BP	2016
China	Guanghui LNG	0.8	Guanghui Energy, Shell	2016
China	Hainan LNG Expansion	1.3	CNOOC	2016
China	Jiangsu Rudong LNG Expansion	4.1	CNPC (Kunlun Energy)	2016
China	Qingdao Expansion	4.8	Sinopec	2016
China	Shenzhen	4.1	CNPC (Petro China)	2016
China	Yuedong LNG	2.7	CNOOC	2016
Colombia	Cartagena FSRU	4.1	Sacyr Industrial	2016
Greece	Revithoussa Expansion	2.0	DESFA SA	2016
Haiti	Maurice Bonnefil LNG Import Terminal	0.4	Haytrac Power and Gas	2016
Philippines	Philippines LNG	4.1	Energy World Corp.	2016
Sweden	Gothenburg LNG	0.7	Swedegas	2016
China	Tianjin North	4.1	Sinopec	2017
Ghana	Ghana FSRU	7.5	West African Gas, Golar LNG	2017
Indonesia	Cilacap FSRU	1.6	Pertamina	2017
Malta	Malta FSRU	0.6	Electrogas Malta	2017
Pakistan	Pakistan FSRU 2	7.8	Pakistan GasPort	2017
Korea	Boryeong LNG	4.1	GS Caltex, SK E&S	2017
Korea	Samcheok Expansion	6.3	KOGAS	2017
Thailand	Map Ta Phut Expansion	6.8	PTT LNG	2017
Uruguay	GNL del Plata FSRU	5.5	Gas Sayago, Mitsui OSK Lines	2017
Bangladesh	Bangladesh FSRU	5.2	Excelerate Energy, etrobangla	2018
China	Fujian LNG Expansion	1.5	CNOOC	2018
China	Zhoushan ENN LNG	4.1	ENN	2018
Finland	Manga LNG	0.5	Manga Terminal Oy	2018
India	Ennore LNG	6.8	Indian Oil Corporation	2018
Japan	Soma LNG	1.4	JAPEX	2018
Japan	Toyama Shin-Minato	1.4	Hokuriku Electric	2018
Singapore	Jurong Expansion	6.7	SLNG	2018
Chinese Taipei	Taichung Expansion	2.0	CPC	2018
India	Dhamra LNG	6.8	Indian Oil Corporation	2019
Total		**118.2**		

Source: Authors' calculations from International Energy Agency data.

Despite the potential, it is a particularly difficult question about what is going to occur in India's energy landscape. Figure 27 shows that although primary energy demand in the last five years has been strong, consumption of natural gas grew less than other fuels and lost market share as a result. Looking forward, most international organisations predict very strong growth in energy demand and weak production growth in India. At present, natural gas lacks penetration in India because distribution channels are underdeveloped. To assess the possible emergence of India as a major LNG customer of Australia, it is recommended that Australian investors follow distribution network policies in India closely. Expansion plans in India are heavily managed by government authorities and subject to a great deal of uncertainty. The major pipeline projects to follow are listed in Table 10, which shows that Indian authorities seem to have committed to ambitious projects.

Figure 27 Primary energy consumption in India, in mtoe, 2010 to 2015



Source: Authors' calculations from International Energy Agency data.

Table 10 Planned pipeline developments in Asia Pacific

Major pipeline projects in Asia Pacific	
Name	Characteristics
Trans-Afghanistan (TAPI) Natural Gas Pipeline	Coverage: Turkmenistan (Galkynysh Gas field)-Afghanistan-Pakistan-India (Fazilka) Length: 1814 km Commencement date in Turkmenistan: 13/12/15 Company: Turkmengaz (company building pipeline) Expected Operational by 2019 Capacity: 33 bcm per annum capacity Notes: Originally signed plans in 1995 (delayed due to Taliban attacks). New deal signed in 2002. Cost estimated at US$10bn. Recently (04/16) a contract was signed by TAPI shareholders, providing an initial budget of over US$200m to fund the next phase. Pipeline is expected to unlock economic opportunities, transform infrastructure and diversify the energy market for Turkmenistan and enhance energy security for the region
Altai Natural Gas Pipeline	Coverage: Western Siberia to North Western China Commencement date in Yakutsk: 09/14 Length: 2800 km Capacity: 30 bcm per annum Other details: Deal signed in 2006 (put on hold due to disagreements over natural gas price and competition from other gas sources in the Chinese market)
Kashmir Natural Gas Pipeline (India)	Coverage: Mehsana - Bhatinda – Jammu – Srinagar Capacity: 11 Billion Cubic meters per annum Estimated completion date: 2019 (possibly later) Approved by Indian government 2013 Notes: Delays due to reluctance of Haryana government to issue its no objection notice for laying the main gas pipeline from the national gas grid.
Mallavaram – Bhilwara Pipeline (India)	Coverage: Mallavaram – Bhilwara Length: 1584 km Capacity: 11 Billion cubic meters per annum capacity Estimated completion: 2017 Notes: Transporting production and imports from India's east coast.
Surat – Paradip Pipeline (India)	Coverage: Passes through Maharashtra and Chhattisgarh (including 5 spur lines) Length: 1724km Notes: Destination is Indian Oil Corp's 15 MTPY refinery in Paradip
Jagdishpur – Haldia Pipeline (India)	Length: 2050km Aims to connect Eastern India to the national grid Initial phase capacity: 2.7 bcm per annum Total capacity reaching 5.8 Billion Cubic Meters annually Notes: Passes through 13 districts in Bihar supplying both a refinery there and a refinery in Barauni. Also will supply local gas networks in Barauni, Gaya and Patna. I will cost US$2bn.
Iran – Oman Pipeline	Notes: Tasnim news agency (Iran) reported commencement of preliminary studies for the construction of this pipeline – 11/15. Contract has been signed by the managing directors of the National Iranian Gas Export Company and Iranian Offshore Engineering and Construction. Offshore studies will be conducted by the Iranian Offshore Engineering and Construction company. Studies for onshore sections of the pipeline have been undertaken by Pars Consulting Engineers Co.
Karachi (Russia) – Lahore (Pakistan) Pipeline (AKA North-South pipeline)	Length: 1100km Length Capacity: 12.4 bcm per annum Estimated completion: Stage 1 – Mid 2018, Stage 2 – Mid 2019, Stage 3 – Mid 2020 Operator: Russia's RT Global Resources (25 year contract) – After termination of the contract the pipeline will be handed over to the Pakistan government Notes: Pakistan has plans for a large-scale development of the country's energy sector. Regasification terminals are currently under construction in Karachi. Project to be completed in 3 stages
Northern Territory (Tennant Creek) – Queensland (Mount Isa) Pipeline	Length: 622km Length Estimated completion date: 2018 Estimated budget: $614m pipeline Notes: Recently downscaled (pipe capacity). It will transport from Queensland to Northern Territory from 3 coal seam gas-to-LNG projects.

Source: Authors' own compilation.

Evolution of the Australian gas industry: From greenfield to brownfield

The sharp decline in oil prices and the slowdown in Asia's demand growth were unexpected events for many market participants five years ago. As a result, some previously announced projects have been cancelled in Australia. Nevertheless, the vast majority of projects started before the oil price decline and had already committed sunk capital by the time oil prices dropped. Most projects have gone ahead and survived this critical stage, as demonstrated in Table 11. There is evidence that Australian LNG investment remains strong and leads internationally. It is also clear that exporting capacity will increase at least until 2020. The transition through this critical period has not been without a cost. Expected cash flows have deteriorated, and some projects were downsized.

It is worth remarking that many of the pre-arranged developments in Table 11 were greenfield projects. Those have or will become operational 6-8 years after the final investment decision date. Going beyond 2020, we would expect brownfield projects to dominate as the Australian gas market matures. Under this market structure, there will be more opportunity for small firms to make relatively small contributions to the supply chain. Consequently, the supply chain will become more competitive. There will be more firms with less market share each, and more supply segmentation. The latter means division of the different stages of the supply chain, including: exploration activities, drilling activities, equipment supply, waste treatment, distribution, liquefaction, storage, cargos, production supplies, etc. This scenario also envisions more specialisation, and R&D to enable comparative advantage in the supply chain through patents. Compared to the greenfield scenario prevailing a few years back, the brownfield one will require less fixed investment entry barriers. It is important to recognise again that Australia has taken this huge first step. To illustrate the importance of this first step, compare Australia's situation with Canada's. Although natural gas in Canada in highly developed, LNG investment in Canada has not taken off. Australia has a first-mover advantage.

With the brownfield environment new challenges will come. Companies in Australia will have to become more accustomed to a highly competitive environment. The US experience suggests that LNG exporters have become accustomed to selling at a price that is close to the resource marginal cost. The natural gas market in the US is highly competitive in each stage of the supply chain and, coming from this environment, American LNG suppliers have been happy to sell LNG to Europe and Asia at a price just above perceived marginal cost. The bottom line for US LNG suppliers is determined by the Henry Hub price (the domestic price or opportunity cost) plus liquefaction costs, transportation costs, tariffs and a small normal profit. When the price at the Henry Hub was US$2/mbtu, prices in the range US$3.5 to 4/mbtu in Asia (depending on the destination) seemed to have been above the marginal cost in the US, but arguably not high enough as to recover initial investments quickly, as happened with Australian LNG producers during the high oil price era. A key difference between the Australian iron ore and the natural gas industries is that the former is, internationally, far less concentrated and competitive than the former, and stakeholders should be always aware of that.

To move away from low-profit competitive sections of the supply chain, Australian gas producers will have to be innovative in ways of achieving profit. Firms will have to carefully consider all available options such as the ones identified here: diversifying portfolios across contracts of different duration and pricing scheme; diversifying their development portfolios across different natural gas types at various scales; exploiting gained experience by developing a range of different producing wells to improve R&D and taking comparative cost advantages; considering different shipping options, as well as cost-sharing and risk-sharing with other companies operating locally.

Table 11 LNG Projects under way, 2016

Country	Project	Bcm pa	Participants	Decision date	First cargo
Malaysia	MLNG (T9)	4.9	Petronas	2013	2016
Malaysia	Petronas FLNG SATU	1.6	Petronas	2012	2016
Australia	Gorgon LNG (T3)	7.1	Chevron, Shell, ExxonMobil	2009	2017
Australia	Wheatstone LNG (T1)	6.1	Chevron, KUFPEC, Woodside	2011	2017
Indonesia	Sengkang LNG	0.7	Energy World Corporation	2011	2017
United States	Sabine Pass (T3-T4)	12.2	Cheniere Energy	2013	2017
Australia	Prelude FLNG	4.9	Shell, Inpex, KOGAS, CPC	2011	2018
Australia	Ichthys LNG (T1-T2)	12.1	Inpex, Total	2012	2018
Australia	Wheatstone LNG (T2)	6.1	Chevron, KUFPEC, Woodside	2011	2018
Russian Federation*	Yamal LNG (T1)	7.5	Novatek, Total	2013	2018
United States	Cameron LNG (T1)	6.1	Sempra Energy	2014	2018
United States	Dominion Cove Point LNG	7.1	Dominion	2014	2018
Cameroon	Cameroon FLNG	3.3	SNH, Perenco, Golar	2015	2019
Russia	Yamal LNG (T2)	7.5	Novatek, Total	2013	2019
United States	Corpus Christi LNG (T1)	6.1	Cheniere Energy	2015	2019
United States	Cameron LNG (T2-T3)	12.2	Sempra Energy	2014	2019
United States	Freeport LNG (T1-T2)	12.6	Freeport, Macquarie	2014	2019
United States	Sabine Pass (T5)	6.1	Cheniere Energy	2015	2019
Malaysia	Petronas FLNG 2	2.0	Petronas	2014	2020
Russia	Yamal LNG (T3)	7.5	Novatek, Total	2013	2020
United States	Corpus Christi LNG (T2)	6.1	Cheniere Energy	2015	2020
United States	Freeport LNG (T3)	6.3	Freeport, Macquarie	2015	2020
Indonesia	Tangguh LNG (T3)	5.2	BP	2016	2021
Total		**151.3**			

Note: Correct as of October 2016.
Source: Authors' calculations from International Energy Agency data.

Policy: The road ahead

Both the new developments in the gas industry and the rapid-changing international environment suggest that Australian policy maker's decisions will have substantial impact on Australian gas and the nation's prosperity. To achieve their objectives and enhance the interests of all the stakeholders –industry, environmentalists, and the Australian public in general- policy makers will have to work on several fronts. Below, we identify Seven Policy Pillars that we consider important.

Pillar 1: Develop credibility

Along the years to come, Australian policy makers should maintain an open communication channel with the gas industry. In doing so, authorities should maintain transparency and make their moves anticipatable. We say that because there have been instances in which unexpected tax and royalty hikes took the minerals industry by surprise (e.g. oil and gas majors are currently concerned about government plans to change the petroleum resource rent tax), creating substantial trouble between state- and federal-level policy makers. It is just too easy to raise taxes once important investment decisions are committed. The current number of long-run projects under way offers plenty of temptation of this type. The basic problem is that these policies are beneficial in the short-run but detrimental in the long-run. It is in the interest of prosperity to focus on the long run.

Nevertheless, government rulings and taxes are unavoidable. Changes in policies and taxes change the risk profile of the country, a concept known as sovereign risk. As sovereign risk increases the necessary profit and rate of return on investment increases. Because there a fewer higher profit opportunities, the amount of investment declines. Taking this into account, the government should act in ways that minimise sovereign risk. This will improve its position in the international market for foreign investment (Trench, Packey & Sykes, 2014).

The first question for Australian policy makers is how much they want to support the local industry. So far, the Australian industry has benefited from shale resource technological developments that were produced mostly in the US, but are transferrable across borders. It is worth remarking that the US industry achieved such breakthroughs through considerable government support in the form of private-public R&D initiatives and tax incentives MIT (2011). Similarly, the Australian Government should act in ways (e.g. with research funding and infrastructure development) that enables industry to more readily access and develop Australia's considerable potential conventional and unconventional energy resources.

For policy makers, there is a trade-off between short-run tax benefits and long-run interests. Credibility through long-term commitment is the most important of the two.

Pillar 2: Innovation support

Australia has now reached a point in which it is set to become a world leader as the world's largest LNG exporter by 2020. Our view is that this status might not last without substantive investment and innovation. This is simply because competing gas developers in the US, China and other places receive substantial government R&D support.

There is a unique opportunity for Australia to continue to develop *first-mover advantages* that involve LNG technological know-how. There are also substantial transferable resources in the iron ore and resource sector in general. That includes

If key international competitors continue to receive substantial R&D support from their governments, Australian policy makers will have to decide whether to match it or let the industry fall in the long run.

The Australian government is faced with a unique opportunity for establishing international leadership in the natural gas sector through first-mover advantages.

specialised human capital (engineers, geologists, etc.), entrepreneurial experience with large scale projects, a high stock of specialised capital goods, and so on. However, if Australia is to remain at the forefront, the Australian government should not do less than its competitors in terms of support. Critical decisions for commitment in this area will have to be made and signalled to investors because there might not be a 'middle way' for Australia.

In modern history, the Australian government has found ways of providing innovative solutions to industry demands. We identify two possible future initiatives for innovation. The first possible public-private initiative to consider would be financial support for purchasing LNG cargo ships with re-gasification capabilities. As was explained, these ships would unleash a whole new spectrum of supply destinations. It would allow not only for securing buyers to avoid supply overhangs, but also for increasing the price received by local suppliers. Overall, it could substantially increase investment in the sector and create new jobs plus additional wealth that would cascade across all sectors of the economy. The relevant question here is whether or not the additional generated wealth will outweigh the cost of the program.

The second proposed innovative initiative is to develop closer R&D ties with leading unconventional gas researchers and LNG suppliers. At present, R&D technological experiments take place where they are best supported, arriving to Australia years later when multi-national firms decide to bring the new technologies. This statement is made based on the shale breakthrough experience. It would have been desirable to have simultaneously developed these technologies with US partners through joint R&D collaboration. Sharing the cost of R&D would also enable the industry to achieve more ambitious technological developments and be at the forefront where it wants to be. The most natural potential partners would be the US and China. China has substantially reduced the cost of its own extraction of shale gas and CBM with government support. If this policy is to be considered, it should start with an open consultation process with the industry, to identify needs and potential. In the current state of affairs, it is not very clear how the Australian government should support R&D activities. Given the size and scope of the resources in Australia, the nation would benefit from a strategic and sustained governmental policy on R&D activities.

Pillar 3: Improved national coordination of regulation activities

Some activities are simply better conducted at Federal level. There are many instances in which states produce overlapping research, regulation and administration. Given the institutional and legal framework of Australia, some overlap is expected. However, in the natural gas sector in particular, the conjunction of overlapping activities has evolved to become complex and inefficient. The main problem is that this *multiplies the cost of research, regulation or administration* at the expense of the taxpayer. Each state has its own department of energy or equivalent and conducts research in order to understand regulation and safety needs. This often occurs with little cross-state collaboration. For instance, the regulations that apply to shale and tight gas activities in WA, summarised in Government of WA (2015), pre-date and are very different to Queensland's regulations. In turn, NSW authorities

have established a moratorium which suggests their views oppose those in WA and Queensland. In our view, these policy developments have included research activities that could have been less costly and better conducted with a single body of experts. Independent of the differences in opinion on whether or not a state's resource should be developed, there is enough ground for commonly developed research and rules. Legally, it is not possible to force states to follow a common Federal policy but more voluntarily-agreed common sets of rules would be a desirable outcome. This common ground could cover research for the regulation of licences, exploration construction, and extraction activities, and environmental safety aspects, pipelines, storage and closure.

When it comes to the regulation of pipelines, substantial differences are found across states. There is a common regulatory framework set out by the National Gas Law (NGL) and the National Gas Rules (NGR), both enacted in 2008. However, these regulations only apply to scheme pipelines (that is, pipelines that form part of a regulated market). Whereas distribution pipelines are highly regulated, with Lowe (2013) finding only 12 of 33 transmission pipelines within Australia were regulated.

In eastern states that are part of the National Electricity Market (a misnomer as the eastern market is not connected to WA), substantial cooperation has been achieved through regulators and initiatives. This has led for fluent pipeline gas trade among states and implementation of innovative trading instruments such as swaps. However, substantial differences still remain. Victoria follows a market carriage arrangement (mainly because the network was designed this way since its inception), and all other eastern states use a contract carriage approach[4]. As a whole, the domestic natural gas markets within the National Electricity Network are regulated by a set of rules coming from the conjunction NGL, NGR, the National Gas Emergency Protocol for cross-border operations, electricity market rules, and state and local regulation. With expectations of international LNG prices impacting prices of Queensland's domestic gas supply, even more complex rules might come into play in the future. None of these include Western Australia.

Western Australia produces around 90 per cent of Australia's conventional gas output in the Carnarvon and Browse basins. These gas fields provide for the LNG export industry and the state's domestic gas market.

The Western Australian Government's domestic gas policy aims to provide for the state's long-term energy needs by requiring LNG export projects to provide natural gas to the domestic market, with 15 per cent of gas from new offshore developments committed for domestic use. The Strategic Energy Initiative's' *Energy 2031'* final paper stipulates that gas producers must demonstrate their ability to meet the Domestic Gas Policy as a condition of project approval (Government of Western Australia, 2017).

Generally speaking, the learning process is quite costly for investors needing to understand the licence schemes, codes and rules to trade gas domestically. A common and generally accepted uniform set of rules would facilitate development. Although this could take a significant amount of time and effort to accomplish, the end product could be worth it.

Some gas-related state government that involve research, regulation and administration would be better conducted at Federal level or with increased cross-state collaboration. Further natural gas TPE regulation will be needed, and the regulation of pipeline schemes should be simplified.

4 Under a market carriage arrangement, market participants provide injection/withdrawal bids that are coordinated throughout the network by a market operator. In a contract market model, the owner of the network enters into transportation contracts directly with shippers.

Turning our attention to third party access (TPA) policy, the Commonwealth Competition and Consumer Act 2010 (CCCA) applies in all states. If there is no other specific regulation on top, the Australian Competition and Consumer Commission has power investigate TPA issues and present cases to the Australian Federal Court. Looking forward, Australia will need specific TPA natural gas regulations. This is especially true now that we are entering the brownfield era, in which firms could potentially share infrastructure and common resources. The basic idea behind TPA is that any firm should be able to access some defined infrastructure. This includes mainly infrastructure that has come into existence from natural monopolies. Lowering the cost of entering the market increases the number of firms promoting competition. Accurately defining which infrastructure should be given TPA, with specific pricing rules for compensating its owner, is important for this policy to work is. We should not forget that TPA policies were instrumental in the development of the US natural gas market. One does not want to repeat the competition thwarting proprietary difficulties found historically in Western Australian iron ore transportation.

Finally, we would like to remark that innovative policies could arise from combining TPA policies with government support. For instance, policy makers could consider the following scheme for LNG ships with re-gasification capability. The ship could be purchased by the government and become available to any firm that wishes to use it at pre-established price. The price would be set at a level that covers the usage cost plus a compensation high enough to repay the purchase (with some interest) over some long-term timeframe. This policy would be most useful if firms failed to acquire such equipment, the number of acquired ships was too low, or there were high perceived benefits to be made from increased competition.

Pillar 4: Improved information and transparency

It would be desirable to have an agency to compile and disseminate energy data, beyond electricity markets, as the energy industry has grown and become more diverse.

Investment decisions are better made when the alternatives are known based on the best available information. For the Australian gas industry, a more extensive, coordinated effort for compilation of data and statistics, and new comprehensive periodical publications would be beneficial. Such need did not seem necessary 15 years ago when the Australian gas industry was in its infancy, but things have changed. The model to follow could be similar to one used at the US Energy Information Administration; i.e. one in which a central government agency compiles and disseminates comprehensive, in-depth national and international data.

When it comes to natural gas market conditions LNG contract lengths and information of production volumes and flows are usually accessible through various sources including newspapers and media releases. However, pricing data is usually very difficult to obtain. If investors start trading LNG on a spot basis, or if Australia is to develop its own liquid market – perhaps integrating with other liquid market(s) in Asia – consistent access to existing prices would be desirable and facilitate trade.

In other energy areas, information and data exist but are dispersed, and not always available on a regular basis. For electricity markets, abundant data and reports are made available. The Australian Department of Industry, Innovation and Science produces a series of comprehensive, periodical publications and statistics.

However, it does not provide enough in-depth coverage of gas markets. Geoscience Australia provides geological surveys. International coverage is mostly found from international sources. In some cases, important information is missing or compiled through one-time, commissioned reports, with Oakley Greenwood (2016) and Core Energy Group (2013) examples of this. Industry participants often need to source the information they need from too many different sources, including unverified ones. More collaboration on this front would be desirable.

A second potential area of improvement could be aimed at educating members of the public on safety and environmental concerns based on findings obtained through comprehensive, independent assessments. It is difficult for the Australian public to know how much safety or restrictions would suffice to achieve acceptable outcomes. Popular beliefs among voters and demonstrators are often formed (or misinformed) from informal sources, such as Internet forums, non-expert opinions and the like. Whatever the findings are, we believe that all parties would benefit from knowing the facts and that would eliminate uncertainty on issues that could have positive effect on potential investors.

A third beneficial transparency action would involve communication of a unified national vision on natural gas development by policy makers. It may not be easy to achieve a unified view on all aspects across states, but a clearly expressed common ground could be agreeable.

Pillar 5: Development of a long-term view on domestic natural gas pricing issues

There have been concerns about the possibility of international LNG prices pushing up domestic gas prices and electricity prices. This could result in substantial reduction in pipeline utilisation, investment on pipelines and increased reliance on Victorian gas (Oakley Greenwood, 2016). The issue has led to substantial current debate on the benefits and costs of a State or Federal reservation policy.

Our general view is that reservation policies do not work. There is no international evidence suggesting that such policies can be maintained over the long run. Typically, reservation policies lead to disinvestment, diminished supply and high prices, with diminished benefits to the parties involved. Several international experiences are reviewed in Energy Quest (2013).

To give a foreign policy-neutral example, we can review the case of Argentina. Argentina is endowed with sizeable deposits of conventional and unconventional gas. It is ranked second in the world in terms of recoverable shale, although none has yet been recovered. It has highly developed pipeline networks for gas transmission and distribution. But, paradoxically, it became a net gas importer in 2008. The policies that led to this outcome were implemented under the administrations of President Nestor Kirchner (2003-2007) and his wife, President Christina Fernandez (2007-2015). Under the reservation policy in place, firms were forced to sell domestically at a low artificial price. Only excess gas over established quotas could be exported. In addition, a general freeze on utility wholesale prices took place, and utilities were subsidised in compensation. In 2011, prices were as follows: US$0.57/

MMbtu for residential use, US$0.97/MMbtu for transport CNG, US$2.60/MMbtu for power generation, and US$3.00/MMbtu for industry. The system implied cross-subsidisation, uncertainty and low profits. The reservation policy led to disinvestment and a supply shortage. To remedy the situation, the Argentine government negotiated several pipeline supply agreements with Bolivia, and the latter used its favourable negotiation power to ensure good deals. The price of imported gas in 2011 was US$10.60/MMbtu. To move away from Bolivian gas dependency, the government decided to seek deals with Venezuela and build two LNG plants to bring gas from the Middle East or Africa. As a result, the main oil and gas company, YPF, was on the verge of bankruptcy and the government had to rescue it by buying the majority of its shares from Repsol. Only very recently, under the new administration, market-friendly policies were introduced. The main problem now is that the reserve policy experiment has eroded confidence from major international oil and gas investors, and it will take a few years to reconstruct the natural gas industry. Other countries that have used similar policies mirroring the Argentine experience have likewise never developed a sizeable natural gas market.

It is our position that the reservation policies simply do not work. A reservation policy would also be incompatible with carbon pricing.

The next point we want to make is that increased domestic gas prices may not be a bad thing from the policy or the public perspective. If the reduction of carbon dioxide is a desirable outcome for the Australian society, then it should be noted that the effects of increased domestic prices through the Queensland LNG channel has essentially the same effect as a carbon tax on natural gas. Both essentially reduce carbon emissions through gas-to-renewable energy substitution in the National Electricity Market, and then industry and households. So, we find that a reservation policy to be highly incompatible with pricing carbon. It would be highly contradictive to establish, let us say, a Federal reservation policy to ensure high domestic gas supply and –at the same time- carbon-taxing gas supply to reduce it.

Finally, we would like to emphasise that the effects on retail gas prices may not be very high. This is based on the natural gas price inquiry commissioned to Oakley Greenwood (2016) that reviews price formation across different states and sectors. The report finds that in 2015, the wholesale price was only a small proportion of the residential retail gas price. It was about 15 per cent in Tasmania, 18 per cent in metropolitan NSW, 22 per cent in ACT, 18 per cent in SA, 17 per cent in Queensland, 28 per cent in Victoria, and 21 per cent in WA. Across Australia, 76 per cent of the retail charges were attributable to distribution (42%), transmission (8%), and retailer component (24%) charges. In WA, retail prices increased in real terms each year between 2007 and 2015. However, the price that large industrial customers paid for natural gas in WA actually decreased by about 60 per cent between 2008 and 2015 following the trend in oil prices. This makes the point that international shocks are not too relevant for determining retail charges.

Calculations for retail electricity prices are slightly more complicated considering the energy mix, but they would likewise show that the impact of wholesale gas prices on electricity prices would be relatively small. As for industrial users of natural gas and electricity, they may be more severely affected by international price shocks. Our view is that the Australian government should not intervene the industrial consumers segment of the energy market. It is more efficient to let the market forces re-allocate the resources of the economy. However, if increased industrial production costs are a

problem the government perspective, then the second-best solution is not to be found in a cross-sector subsidisation scheme that would make producers of both gas and manufactured goods more inefficient and ultimately independently unsustainable.

Almost all major gas producing nations have some form of gas reservation policy or law. However, natural gas reservation policies vary substantially in terms of implementation method and impact on the domestic market. While the common theme of such policies is to help ensure local industry and the domestic population are not disadvantaged by gas exports, opponents argue that limiting access to international markets will push prices artificially low, discourage exploration investment and hurt natural gas markets over the long term.

In some nations, there are clearly defined government policies mandating domestic natural gas supply for existing plants. For instance, Indonesia has federal laws mandating that existing projects are required to reserve at least 25 per cent of total natural gas production for domestic markets. For new projects, the policy is applied on a case-by-case basis and the prescribed reservation can be up to 40 per cent. For example, the recent Tangguh Train 3 project is required to reserve 40 per cent for the Indonesian market. The Indonesian Energy Minister has also indicated that – if economically feasible at domestic prices – it will aim to encourage 100 per cent of natural gas production for domestic use. However, the gas reservation policy is not applied uniformly across projects due to differing project costs. For instance, in 2015 the Indonesian Energy Minister indicated that as the Chevron Indonesia Deepwater Development has higher project costs, it will need to target overseas markets offering higher prices.

In contrast, Russia has a broadly-defined policy of promoting the domestic gas market via the granting of licences, production sharing agreements or the establishment of public and private partnerships. The Russian government has set out its broad energy policy strategy up to 2020 in an "Energy Strategy" document. Russia largely maintains its domestic advantage of natural gas reserves by having state-owned enterprises as the dominant producer of natural gas. However, in July 2008, the Russian president enacted a law allowing the government to unilaterally allocate strategic natural gas and oil deposits. This has allowed Russia to use its natural resources to its political advantage by securing large loans in exchange for the supply of its natural resources to its international partners, most notably China. Russia also cut natural gas supplies to Europe in 2008 following disputes with the Ukraine.

In the USA, export of natural gas is regulated by the Natural Gas Act (1938). Pursuant to this legislation, exports must be in the "public interest" as determined by the Department of Energy (DOE). This "public interest" test allows the US to maintain control over export volumes to ensure that any domestic increase in natural gas demand does not outstrip supply and thereby create shortages in the domestic market. Similarly, Canada also has a "public interest" test governing the export of its natural gas. In early 2016, the USA began exporting LNG to world markets for the first time since 1957. In January 2017, the United States President announced the pro-gas "America First" energy plan which aims to enhance natural gas exploration and exports, with the goal of becoming one of the world's largest natural gas exporters whilst simultaneously meeting domestic market needs.

The state of natural gas reservation policies in Australia stand in stark contrast to other major natural gas producing nations. Prior to 2017, there was no national policy or law governing natural gas exports. Up to this time, Australia was the only nation to permit the export of natural gas without restriction at the national level. In April 2017, however, the Australian Prime Minister announced the "Australian domestic gas security mechanism" which will allow export controls to be imposed when there is a gas supply shortfall. This policy response followed a period of surging natural gas prices and fears of a gas shortfall, particularly on the east coast of Australia.

Natural gas reservation policies already operate at the state level for Western Australia and, more recently, Queensland. In Western Australia, the state government has negotiated with gas producers in new Liquefied Natural Gas projects to obtain 15 per cent of gas to be supplied for domestic use rather than exported overseas. It is also legislated under state law that 15 per cent of all gas produced must remain for state consumers. Commentators argue that this form of policy has enabled Western Australia to guarantee domestic supply while simultaneously encouraging investment and exports.

More recently, fears of natural gas shortages on the east coast of Australia has seen the Queensland government introduce a natural gas reservation policy. Under Queensland's new gas reservation policy developments, gas exploration permits will be issued on the basis that they are used to supply domestic gas only. The first of such permits was announced in January 2017, where the government released 58sq kilometres of exploration ground in the onshore Surat Basin under the condition that any gas produced must be used in Australia. The policy rational is that development of gas export plants has driven up domestic gas prices and raised concerns about potential domestic gas shortages.

Pillar 6: Management of economic side effects

Another lesson to be learned from international experience is that producing an abundant resource may be economically detrimental for a country if not managed properly, as corroborated by a large number of academic studies across many countries. There are two well-known effects. The first one is the Dutch disease –a term coined by The Economist (1977). It occurs when the development of a natural resource that is exported leads to an exchange rate appreciation, to the point that other industries become uncompetitive. This is due to relatively high export prices and relatively low import prices. The situation becomes more complicated as the leading sector bids away important resources from the other sectors, for instance due to relatively high salaries. This situation resembles the Australian economy during the resource boom. The main conclusion that we can extract is that Australian companies are already familiar with this situation and the government has managed the benefits of the resource boom reasonable well. We consider this management experience an advantage. The second common adverse effect is known in academic literature as the resource curse. It is a paradox suggesting that high endowment of resources in a country may lead to a result (usually in GDP terms) that is less than what the country would have accomplished without the resource endowment. This is usually attributed to poor institutional quality through corruption, concentration

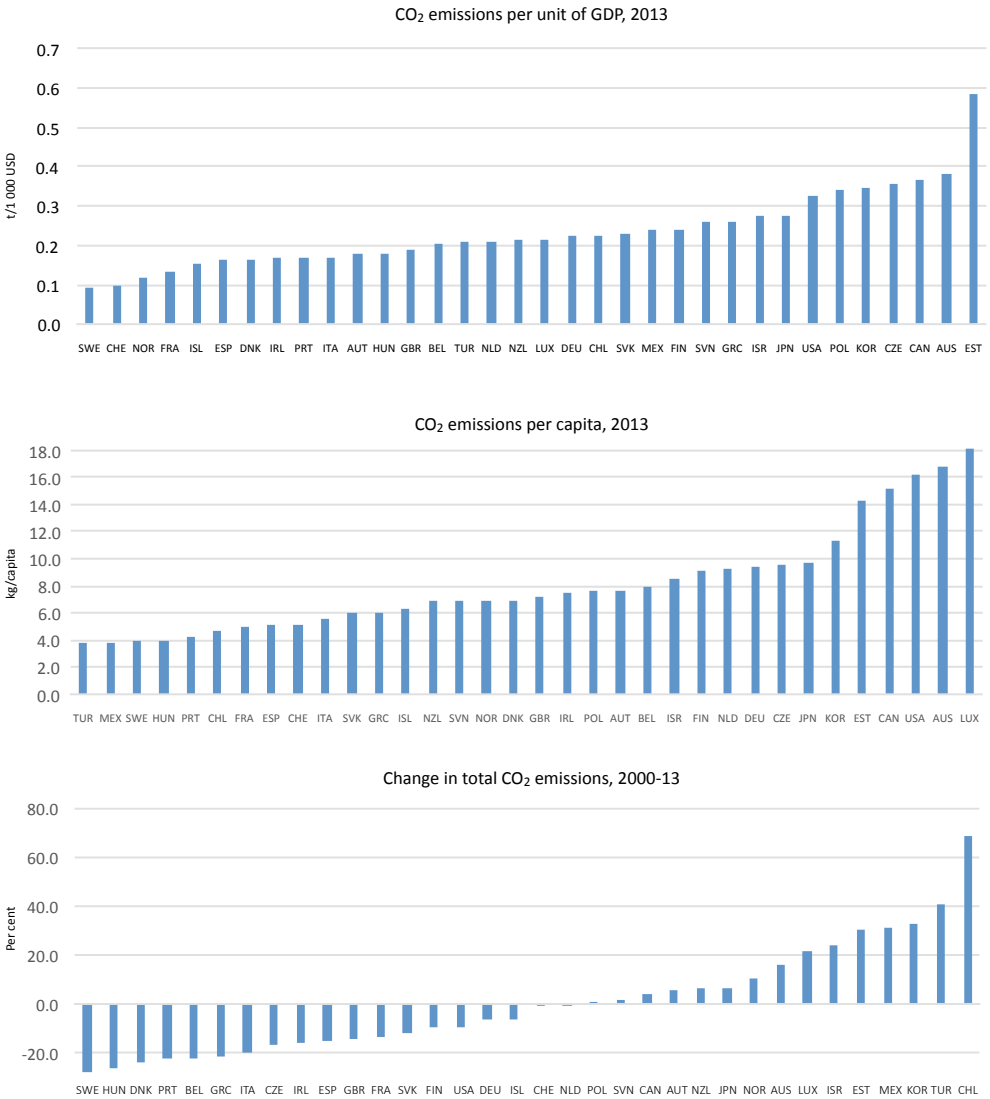
of power, elitism, diminished democratic value and impoverished middle classes. The Australian experience with the resource boom suggests that Australian institutions are much stronger and able, in the most part, to resist some of the negative aspects emanating from its resource endowment.

Pillar 7: Development of a stable long-term carbon dioxide policy

The final policy front to consider is the need for a clearly-defined, long-term carbon policy direction. The level of commitment of other OECD countries is generally much higher than that of Australia, and pressure on policy makers for action is starting to mount. This suggests that the current carbon policy approach is very unlikely to perpetuate. As the carbon tax affects internal natural gas demand and supply it is a concern for Australian gas producers. Overall, there is unresolved uncertainty, and we argue it would be better to address it sooner rather than later. Figure 28 provides an account of Australia's stance in 2013, a year in which the carbon tax was still operational.

There are concerns about future carbon pricing because the previous policy failed at large to bring carbon dioxide emission down to a level that would align with policies in other OECD countries, as Figure 28 shows. The last carbon policy was implemented under the Julia Gillard administration under the Clean Energy Act 2011. It established a carbon tax that would start at $23 per tonne of emitted carbon dioxide in 2012, rise thereafter and be eventually replaced by a trading mechanism. The Law was abolished on 1 July 2014 under the Abbott administration. The policy was meant to reduce heavy industry emissions while keeping its profitability unchanged, an outcome that is theoretically achievable through a combination of income and substitution effects. The income effect was provided in the form of lump-sum compensations to large industrial producers. The substitution effect is the change in energy consumption that a firm makes as a response to the change in relative input prices caused by the carbon tax. Overall, the combination of tax and compensations was not enough incentive for firms to substantially reduce carbon emissions. The options being considered for the trading mechanism involved integrating to the international market (that was dominated by Europe and had an even lower carbon price at the time) or setting some sort of domestic market.

Figure 28 Carbon dioxide emissions in OECD countries, 2000 to 2013



Source: Authors' calculations from International Energy Agency data.

Despite international pressure, there are good reasons for Australian policy makers to establish a standing position on carbon policy that would, to some extent, reduce the uncertainty. In the COP21 agreement, there was lack of enforceable, coordinate agreements, but voluntary concessions were made. In this context, and counter-intuitive as it may first sound, unilateral action may be undesirable. Waiting until a new agreement is reached may be a better strategy. This argument can be demonstrated with a hypothetical example.

The following example involves long-run leakage effects which cannot be corroborated with data as no resembling measurable situation has occurred yet. That means that

this example is a purely hypothetical construction. Suppose that Australia produces 5 units of carbon dioxide emissions and the rest of the world produces 100 units. Let us say that Australia reduces its emissions to 3 units after implementing a carbon tax. Over the long-run, some relocation of heavy industry from Australia to a country where carbon is cheaper may take place. If such place is a developing country, its technology would be inferior, so producing the same amount of output that was produced in Australia would produce more carbon emissions (because capital is more expensive relative to labour in developing countries). Overall, the 2-unit reduction in Australia's carbon dioxide emissions could lead to a 3 unit increase elsewhere. In total, the world would produce 105 units of carbon dioxide before the introduction of Australia's carbon tax, and 106 units after the tax introduction. If the global amount of carbon dioxide is a problem, it is then completely irrelevant how much countries contaminate *individually*. In this very hypothetical example, unilateral action by Australia is harmful at a global level. The main point is that if all countries in the world increased their carbon price simultaneously so that no industry relocation could take place, the outcome would be reduced carbon emissions at the global level. The whole example is illustrated in Table 12. The main conclusion is it may be beneficial to wait and negotiate a coordinated agreement later rather than take unilateral action today. Waiting is a valid policy, but it has to be clearly announced and understood.

Table 12 The global carbon negotiation game with hypothetical values

		Rest of the world	
		Without carbon tax	With carbon tax
Australia	Without carbon tax	Aus = 5, RoW = 100 Total = 105	Aus = 7, RoW = 95 Total = 102
	With carbon tax	Aus = 3, RoW = 103 Total = 106	Aus = 4, RoW = 90 Total = 94

Source: Authors' own example.

Natural gas generation, in the electricity market, may benefit from carbon dioxide reducing policies in two ways. First, natural gas fired generation produces 60 per cent less carbon dioxide emissions than traditional coal fired electricity generation. By replacing retiring or old coal fired electricity generators with natural gas fired generators, the amount of carbon dioxide released into the atmosphere will be 40 per cent of existing levels for each of the replaced coal fired units. This is one way the USA has significantly reduced its carbon dioxide emissions.

Second, there is a desire to employ more renewable energy technologies. Some of these technologies are intermittent or variable (e.g. wind). It is necessary to provide production support for the variable renewable energy technologies electricity production with back up generation. This is called spinning reserves. Spinning reserves are important because a sudden decease in generation can cause power disruptions. Spinning reserves alleviates the power interruption problem by quickly going on line and continuing uninterrupted service. One of the best spinning reserve generators is the natural gas turbine generator - from speed of ramp up and ability to synchronise with the transmission grid points of view. When added to this, that natural gas has lower in carbon dioxide emissions than coal or oil fired generation, it makes sense for natural gas electricity generators to be used as the spinning reserve generator for variable renewable energy technology generators. Both of these situations can potentially - significantly - lead to increased demand for natural gas.

So, can we expect a second resources boom?

All in all, the short answer is yes. The Australian gas industry has the potential to unleash vast wealth to the Australian economy. However, there are external and internal risks that may affect this outcome. We discuss them in the next section. The main recommendation for industry participants is to follow the events identified in this report. Policy makers should understand that their stance will be important, if not critical.

Discussion

and conclusion

Discussion and conclusion

Based on the work presented in this report it is possible to identify strengths, weaknesses, opportunities, and threats (SWOT) for the Australian natural gas sector. To accomplish this we have reviewed market structures, some aspects of the energy mix and techniques for resource extraction. A summary of our SWOT analysis is given in Table 13, where factors are presented in no particular order.

There will be ample opportunity for Australian producers to place their supply in Asia. With some analysis of the energy mix and China's Action Plan for Air Pollution Control, we have discovered that coal-to-gas substitution has been used as tool for both meeting energy demand needs and achieving environmental targets. China's plan is expanding and being mimicked in India and other growing Asian nations. An examination of demand trends revealed that most of the growth in the world's natural gas demands over the past few decades has come from Asia, with further examination supporting our beliefs that the prospects for gas demands in Asia looks favourable. Two questions arose in the context of infrastructure: Will there be enough LNG re-gasification facilities at the receiving end? Will gas be able to flow to end-user points at destination countries? The answer to the first question is that there is substantial forthcoming LNG re-gasification capacity for China, Japan and India, and enough in the rest of Asia. As for the second question, China's plan to jointly develop LNG re-gasification facilities and internal distribution networks seems to be working quite well, with Japan and South Korea already having developed distribution infrastructure. Now, questions may be asked about India. The evidence suggests that Indian policy makers are committed to major projects, however there have been frequent interruptions and postponements which could slow down natural gas penetration. A review of academic literature on causality suggests that we can expect high natural gas demand in developing countries of Asia, if there is high income growth.

Now that we know that gas can flow regularly from Australia to Asia, the next question relates to the amount of money Australian LNG exporters will receive. The investigation revealed that natural gas markets around the world are regional. The North American market, the European market and the Asia Pacific market are the main intra-trade blocks. In Asia, LNG is particularly important. The pricing mechanism in each of these blocks has distinctive market characteristics to it. In Asia, the preference has been to price natural gas against oil through long-term contracts (this decision was made not because gas and oil may have some degree of substitution but because there was no better reference point reflecting opportunity costs for Alaskan producers when natural gas trade with Japan started).

Australian companies have secured a large number of long-term oil contracts. So much so that the country is set to become the major LNG exporter by 2020. Oil-indexed contracts were preferred by both Australian investors and Asian investors wanting to secure diversification away from major pipelines. However, more and more gas-on-gas pricing has taken place in Asia in recent times. Most of these contracts are offered by US suppliers, with flexibility on volumes. Within the last two years, trading hubs have been introduced in Singapore, China, Korea and Japan, with not enough significant trade to date. However, liquid markets are expected to quickly grow and if that occurs there will be markets in Asia that follow natural gas demand and supply forces rather than oil prices. Australian companies have been very cautious so far but will have to soon start looking at their pricing options.

The Australian LNG industry was doing better 6 years ago when the oil price was high. Considering that oil prices are so important for gas pricing we conducted an examination of the 'global' oil market (unlike natural gas, oil markets are highly integrated). An interesting finding in the oil chapter is that at least one major supply disruption occurs in a decade. Supply disruptions, even when they are relatively small, can produce large increases in oil prices. The implication of this is that oil prices may not remain at the current level (although we do not see reason for it to change substantially in absence of supply shocks). Essentially, oil prices are difficult to predict. It seems that a few years back not all Australian gas producers or market analysts in general foresaw the drop in oil prices and slowdown in LNG demand. However, many of the firms had already sunk capital before the events developed, and for that reason, the industry survived its most critical moment.

In the coming years, Australian producers will face several dilemmas. Our advice is to use all the available options and try to diversify risk and innovate. The new liquid market will provide plenty of opportunity for diversifying across short-term gas-on-gas contracts, and traditional long-term oil-indexed contracts. Additionally, a producer could diversify by developing small-scale, large-scale and offshore resources simultaneously. Doing so would allow for introducing new R&D activities and breakthroughs. From being a world leader, the industry will receive a know-how first-mover advantage. Producers should use, and not waste, this opportunity to remain in front. Among the potential developments we see major breakthroughs coming from floating LNG technologies. A recent development that Australian producers could look into are ships with re-gasification capacity.

Finally, we want to say that all the achievements of the Australian LNG industry might not be sustained over the long run without sustained government R&D support. This is because main competitors do receive substantial R&D support. There are alternatives for support, and we think that sharing R&D with leading nations in the natural gas and LNG industries, as well as supporting infrastructure would be desirable. This is not the only front in which the Australian government could help, there is also a need for simplification of regulation, more cross-state cooperation, improved data collection and dissemination, and more fluent communication.

Table 13 SWOT analysis of Australian natural gas industry

Strengths	Weaknesses
• Vast endowments of all types of gas, onshore and offshore • Strategically situated near LNG outlets, relative to competition • Post-resource boom: economy adaptable to a gas boom • Enough projects under way • Has passed its most critical development stage yet • Entering a mature brownfield stage post 2020 • Advanced know-how • Leadership as world's main LNG exporter by 2020 • Has potential to find ways of innovating, especially based on experience of past decade	• Various domestic regulations leading to complexity and increases transaction costs • Not enough shared information, technology and infrastructure • Over-reliance on long-term contracts • High labour costs and taxes • Uncertainty in some policy fronts, including future of carbon policy and fiscal regime • Industry still highly concentrated • Companies in Australia might be too slow to react to rapid-changing market and economic conditions • Without new investment, the 2020 leadership position can be easily lost
Opportunities	**Threats**
• Could establish itself the leading LNG industry in the world • Plenty of gas-for-fuel substitution in China/Asia • Demand LR prospects for gas and LNG in Asia remain strong • Diversification between LR oil-indexed and SR flexibly-priced contracts • New gas-on-gas price opportunities • Plenty of potential for use of new floating LNG infrastructure • Ships with re-gasification might be the new 'game changer' and a 'market maker' • Oil disruption might increase oil prices in the future • Adequate policy management experience • New LNG destinations might be found; e.g. in S. Asia and S. America	• US competition may offer better terms to Asia: volume and price flexibility • Oil prices might remain low for a long time • Qatar might lift self-imposed moratorium and unleash LNG • India's pipeline infrastructure may not develop rapidly enough • Russia might increase LNG and pipeline supply • China might increase unconventional gas supply in the LR • Reservation policy in Queensland • Policy makers might not support the industry • NSW not supportive of CBM development • Uncertainty about new pricing mechanisms

Appendix

Calculation of average annual growth rates

In some sections, we reported average annual growth rates, which were calculated from the following expression:

$A_t = A_0(1+g)^t$,

where A_0 is the initial value of the time series, t is the number of years, A_t is the value of the time series after t years, and g is the annual growth rate.

Example: In Chapter 2, we estimated the average growth rate of the world's production of natural gas for the period 1970 to 2015 at 2.87%. Knowing that t = 45, A_0 = 991.9 *bcm* and A_t = 3,538.6 *bcm*, we estimated:

$$g = \left(\frac{3{,}538.6}{991.9}\right)^{1/45} - 1 = 0.0287.$$

Some useful conversion units

1 billion cubic metre = 0.028 billion cubic feet

1 billion cubic metre of natural gas = 0.90 million tonnes of oil equivalent

1 billion cubic metre of natural gas = 6.60 million barrels of oil equivalent

1 billion cubic metre of natural gas = 35.7 trillion British thermal units (btu)

1 btu = 0.239 kilo-calories = 0.948 kilo-Joules

1 billion cubic metre of natural gas = 0.725 million tonnes of LNG

1 (metric) tonne = 2,204.62 lb

1 (metric) tonne of crude oil = 7.33 barrels of crude oil

1 barrel/day of crude oil = 49.8 tonnes/year crude oil

Glossary

and technical notes

Glossary and technical notes

Asia Pacific

In this study, the Asia Pacific region includes the following countries: Afghanistan, American Samoa, Australia, Bangladesh, Bhutan, Brunei, Cambodia, China, Fiji, French Polynesia, Gilbert-Kiribati, India, Indonesia, Japan, Korea (DPR), Laos, Malaysia, Maldives, Mongolia, Myanmar, Nepal, New Caledonia, New Zealand, Papua New Guinea, Pakistan, Philippines, Republic of Korea, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, Vietnam, and Western Samoa.

Bcm

Billion cubic metres.

Btu

British thermal unit. It is a unit that measures the calorific energy content in fuels or electricity. See also conversion tables in the Appendix.

CIF

A standard methodology for reporting import prices that include Cost, Insurance and Freight.

CNOOC

China National Offshore Oil Corporation.

CNPC

China National Petroleum Corporation.

COP21

United Nations' Conference of the Parties for the 21st Century. It took place in Paris in 2015 and defines directions for climate-change related policies under the United Nations Framework Convention for Climate Change (UNFCC).

LNG

Liquefied natural gas (primarily methane). It is liquefied by reducing its temperature to -162 degrees Celsius at atmospheric pressure.

NMV

Netback Market Value (of LNG). It refers to the effective price to the producer at a specific delivery location, and is calculated considering the contractual natural gas price net of transportation and regasification costs and weighting out the amount of competition with other fuels.

Proved Reserves

The estimated quantities of resource which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under current economic and operating conditions. This definition includes field condensate, natural gas liquids and crude oil.

Refinery throughput

Capacity for refining crude oil.

Tcm

Trillion cubic metres.

Toe

Tonnes of oil equivalent.

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