

# The future of Australian LNG

Global oversupply, shifting demand and growing competition create uncertain outlook for industry

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## Key Findings

**Global liquefied natural gas (LNG) markets are heading towards a supply glut due to unprecedented increases in supply from low-cost producers and weak demand growth.**

Australian LNG producers are likely to become increasingly exposed to LNG spot markets from 2030, which will be awash with uncontracted gas from low-cost Qatar and surplus LNG from portfolio players and major buyers.

Low volumes of economic reserves and high production costs could see some Australian LNG infrastructure mothballed before the end of its useful life, resulting in decommissioning costs being brought forward.

The various financial risks faced by Australian LNG producers could erode the financial returns for existing assets and undermine the business case for new developments.



## Executive summary

Australia's LNG sector underwent a wave of growth from 2012 to 2017, which saw Australia become the world's largest LNG exporter. This is remarkable given the remoteness and relatively small scale of Australia's gas reserves, which are significantly lower than the reserves held by other major LNG exporters.

### A looming supply glut meets shifting demand

From 2025 to 2028, LNG markets are set to increase supply by a staggering 40%. This glut of new, low-cost LNG supply will intensify competition between LNG exporters and traders and place downward pressure on LNG prices.

This coincides with a fundamental shift in demand in LNG markets, with demand in mature markets either falling or set to soon fall, leading to the LNG industry pinning its future on significant new demand in emerging markets. IEEFA, in line with the International Energy Agency (IEA), expects more moderate demand increases in those markets, given the range of barriers to increased structural LNG demand in emerging markets and the competition faced by LNG in power generation from renewable energy and coal.

In emerging markets, government policy is already curbing the rollout of gas generation (coinciding with a greater focus on renewable energy). In China, recent energy policy has heralded a softening of the outlook for gas consumption and a greater emphasis on domestic gas production and on pipeline imports rather than LNG imports. In Vietnam and the Philippines, persistent issues with approval processes and power purchase agreements for LNG-to-power have delayed the commissioning of new gas generation and reduced anticipated LNG demand. Recent high prices have also affected LNG demand, particularly in the price-sensitive markets of South and Southeast Asia, with state-owned utilities incurring material financial costs due to higher prices. At the same time, despite the adverse effects of recent high LNG spot prices, buyers in emerging markets outside China are yet to contract significant new LNG volumes.

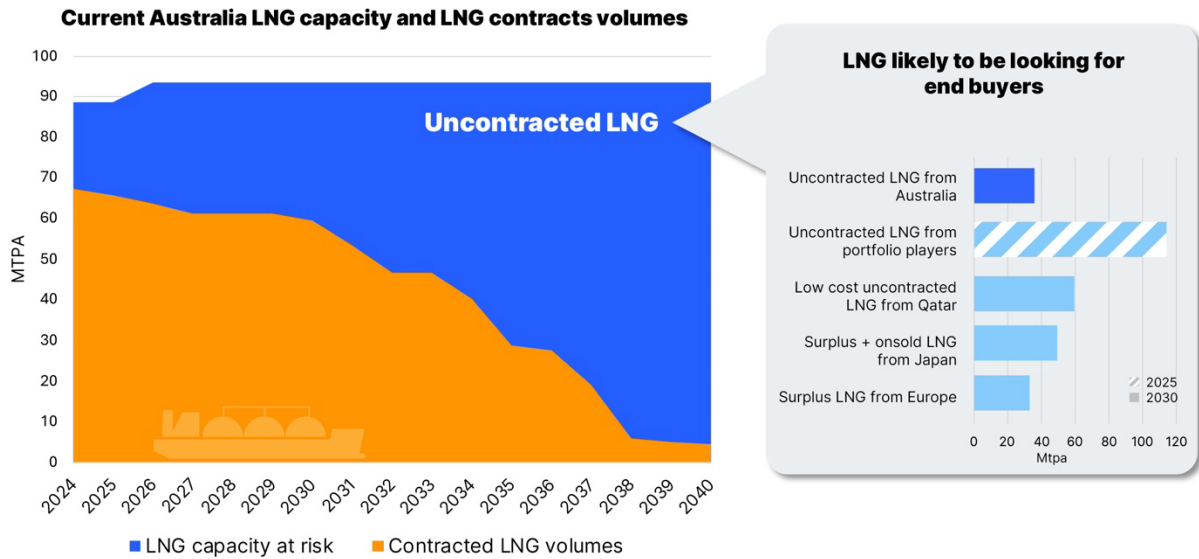
### Growing competition from gas looking for end buyers

Lower-than-anticipated LNG demand and an oversupply due to the massive wave of new investment will create challenging market conditions for Australian LNG exporters. While Australian LNG exporters presently sell about three quarters of their LNG under long-term sale and purchase agreements (SPAs), many of these agreements are set to expire in coming years. This may increase exporters' exposure to spot markets if they are unable to lock in new LNG SPAs in the face of increasing competition, or will put them in competition with other suppliers for contract extensions. In the absence of new LNG SPAs, Australia's uncontracted LNG volumes could represent 34 million tonnes per annum (MTPA) by 2030 and 89MTPA by 2040.

LNG markets are likely to soon be awash with uncontracted LNG, particularly from lowest-cost producer Qatar. By 2030, Qatar could potentially have up to 59MTPA of uncontracted LNG capacity.

LNG portfolio traders are adding to the stock of uncontracted LNG – these traders have purchased significant volumes of impending new supply under long-term SPAs, which they have not yet sold to end users. The IEA estimates that about half of the LNG supply held by portfolio traders remains uncontracted, representing more than 100MTPA in 2025.

**High-cost Australian LNG will soon be uncompetitive in an oversupplied market**



Major LNG buyers are also increasingly facing the problem of surplus LNG supply. IEEFA recently found that Japan’s four largest buyers also have surplus supply, which they are increasingly looking to sell into emerging markets in South and Southeast Asia. Declining demand and gas reduction targets could also lead to nearly 30MTPA surplus LNG in Europe. The IEA also projects that China could be overcontracted by 2030 with existing LNG contracts.

LNG buyers could therefore turn into sellers. Japanese companies already sold more LNG into third countries from 2020-22 than they purchased from Australia. These LNG buyers, who purchase significant quantities of LNG from Australia, have undertaken investments in gas and LNG infrastructure in third countries to drive demand growth for LNG. Government targets suggests that Japan could be selling nearly 50MTPA of LNG by 2030, turning Japan from one of Australia’s largest LNG buyers to potentially one of its largest competitors.

The impending supply glut is also placing pressure on LNG contract prices, with a range of buyers seeking to either reopen negotiations on pricing or seek lower pricing. Market participants, as well as IEEFA, expect that future LNG spot prices will fall due to LNG oversupply, which could lower the returns to Australian LNG producers who are exposed to spot market prices. This includes contracted and uncontracted LNG volumes, with Santos and Mitsubishi having a 10-year LNG SPA for 1.5Mtpa, with pricing based on the Asian LNG spot market price.



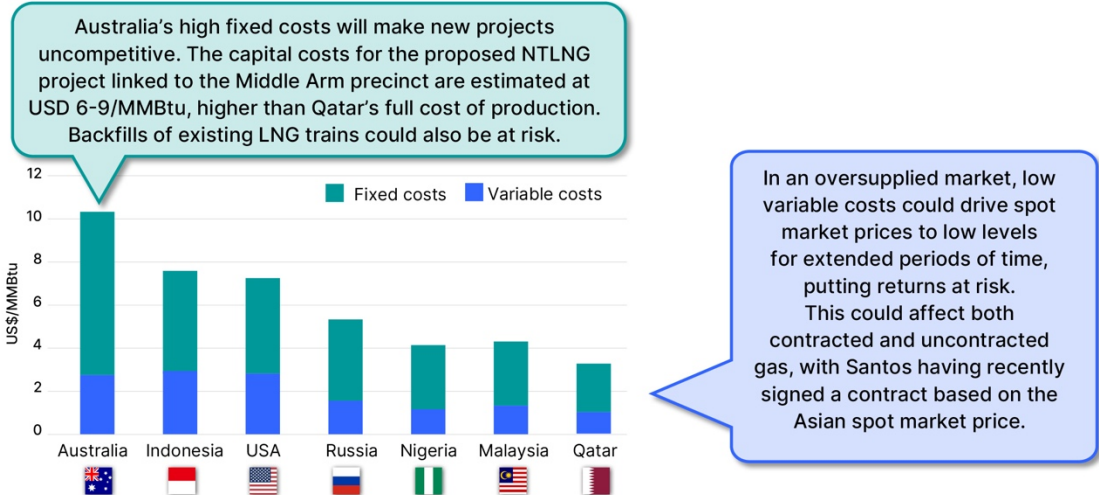
## Uncompetitive costs of production

These challenges, along with Australia’s record of high capital costs (and poor shareholder returns) for existing LNG facilities, means that Australia is unlikely to see any new LNG projects reach final investment decision (FID). There is presently only one proposed new LNG project, junior explorer Tamboran Resources’ NTLNG project, which IEEFA previously estimated would have capital costs between USD6.96-10.44 billion, equating to a cost of about USD6-9 per metric million British thermal units (MMBtu). However, in IEEFA’s opinion, the NTLNG project is likely to struggle to attract sufficient investment to reach FID given Australia’s high-cost reputation and the looming glut in new low-cost supply. This is in line with the Australian government’s Future Gas Strategy analytical report, which assessed that established Australian production would be more competitive than prospective new sites in the current market.

Existing LNG projects may also face cost pressures, with development of some new gas fields to backfill existing LNG projects potentially having higher costs than overseas, particularly Qatar. For example, Santos’s Barossa development was estimated to have a cost of about USD5.5/MMBtu, but delays to the project and the requirement to offset all reservoir CO<sub>2</sub> emissions are likely to have escalated costs.

These costs are much higher than they are in Qatar, which has an estimated LNG marginal cost of about USD2/MMBtu (and a long-term marginal cost of USD4/MMBtu). If Qatar’s revenue from its production of liquids (which are extracted along with gas) is accounted for, Qatar’s marginal LNG production costs are effectively negative. The differential in shipping costs (to North Asia) between Qatar and Australia is unlikely to make a difference – for example, IEEFA estimates the difference in shipping costs in mid-May 2024 to be less than USD0.30/MMBtu.

**Production cost curve of select LNG exporters**



Source: IEEFA, Future Gas Strategy analytical report

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## Australian LNG is entering a declining period

Australia's high costs and impending supply glut are likely to impact on the financial business case for further LNG developments, whether greenfield LNG plants or backfill projects, which could see Australia's export volumes decline in coming years. Low expenditure and declining gas reserves will also constrain Australia's future LNG exports, particularly from 2030 onwards.

Moreover, tightening domestic supply conditions and a need to maintain social licence will likely see gas that could be exported increasingly diverted to the domestic market. LNG exporters may also choose to prioritise domestic supply over discretionary LNG spot sales if domestic prices are higher than LNG spot prices. This could lead to mothballing of LNG and gas infrastructure before the end of its useful life, undermining the returns anticipated at the time of FID. Early retirement of infrastructure would also bring forward decommissioning obligations, with substantial costs.

In addition to creating financial risks for LNG exporters, these factors point to a gloomy future for Australia's LNG export sector, with the volume and value of Australia's LNG exports likely to materially decline over the next decade. It is vital that Australia shifts its focus to developing new export markets in which Australia is likely to have a comparative advantage.



## Introduction

Australia’s liquefied natural gas (LNG) sector has witnessed a remarkable boom in the past decade, propelling Australia to briefly become the world’s largest LNG exporter. However, the sector now faces a challenging future due to declining LNG demand in key markets (which Australia has historically relied upon), uncertainty about new demand in emerging markets, and a looming glut of low-cost LNG supply from key competitors. Australia’s relatively high costs are likely to limit Australian LNG exporters’ ability to compete with this new supply.

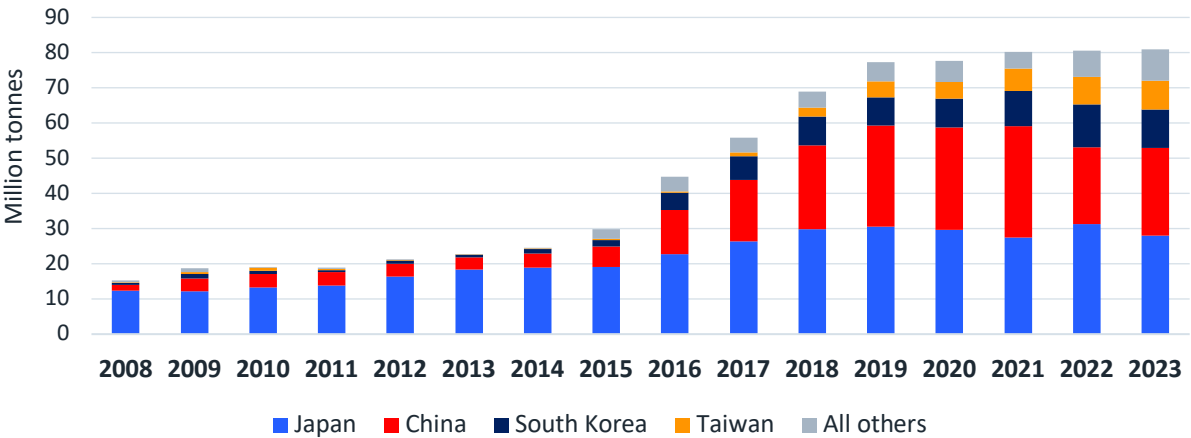
The challenges will be compounded by declining gas reserves and insufficient exploration expenditure in Australia. Tight domestic supply conditions may also see gas slated for export diverted to the domestic market, either to address supply gaps or if domestic prices are higher than those available in LNG markets.

These factors are likely to affect future LNG exports, with the expiry of existing Australian long-term LNG sale and purchase agreements (SPAs – or LNG contracts) likely to expose Australian LNG exporters to LNG spot market pricing. A looming glut is likely to lead to lower LNG spot prices, which could persist without sufficient new demand emerging. Australian LNG exporters also face a range of financial risks, including price risks and the risks of their LNG assets being underutilised or stranded.

## Australia’s LNG exporters rely on key buyers in Asia

Australia has exported LNG to a wide range of countries over the past decade, with cargoes at times travelling as far as South America and Europe. However, Australian exporters rely on LNG buyers in a handful of countries. Historically, Japan, China, South Korea and Taiwan have accounted for almost all of Australia’s LNG exports (Figure 1), with buyers in other Asian countries accounting for only a small proportion of Australia’s LNG exports.

Figure 1: Australia’s LNG exports by country



Source: IEEFA analysis of Kpler LNG data.

The historical reliance on Japan, South Korea, Taiwan and – more recently – China reflects Australia’s proximity to key Asian LNG markets. This provides Australian LNG with a freight cost advantage due to the relatively short shipping distances (LNG freight is typically priced on a per-day basis plus port costs). For example, LNG freight rates in mid-May 2024 suggest that Australian LNG had a freight cost advantage of almost USD0.30 per metric million British thermal units (MMBtu) relative to LNG from Qatar, and about USD0.60/MMBtu from the US.

This proximity, along with a favourable investment environment in Australia, has seen major buyers in Asia enter into numerous LNG SPAs with Australian exporters. Some of these buyers have also directly invested in Australia’s gas and LNG sectors, including by acquiring interests in LNG facilities and a range of upstream gas developments. A recent example is LNG Japan’s purchase of a stake in Woodside’s Scarborough and Pluto Train 2 project.<sup>1</sup>



**The historical reliance on Japan, South Korea, Taiwan and – more recently – China reflects Australia’s proximity to key Asian LNG markets.**

The majority of Australia’s LNG production capacity of 88.2MTPA is currently contracted under long-term LNG SPAs. As at the start of 2024, volumes under LNG SPAs with buyers in Japan, South Korea, China and Taiwan accounted for the vast majority of Australia’s total contracted LNG volumes and the majority of Australia’s total supply capacity.

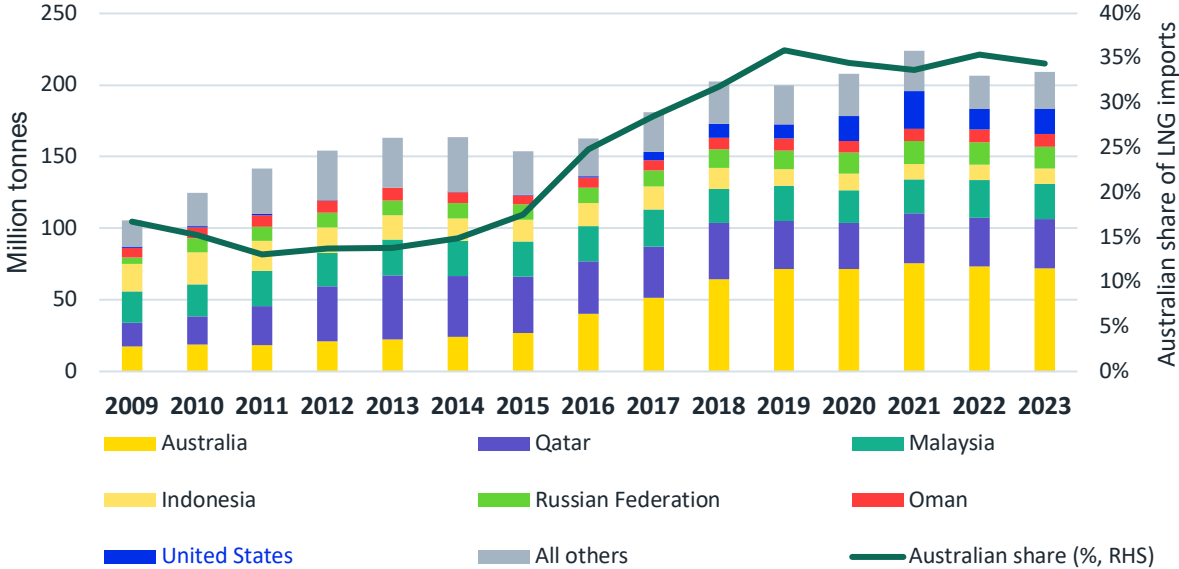
While Australian exporters are reliant on buyers in Asia, these buyers have sought to diversify their LNG supply. Australia’s share of LNG supply to Japan, South Korea, China and Taiwan grew rapidly during the period from 2014 to 2019 (during which Australian LNG capacity significantly increased), but has remained relatively flat since 2019, likely due to LNG capacity not growing since 2019 and increasing competition from US exporters.

By 2023, Australia was the largest LNG supplier to these countries, but still accounted for only slightly more than a third of LNG imports (Figure 2). Across all Asian countries, Australian LNG accounted for about 30% of imports in 2023.

Qatar remains the second largest supplier to Asia, with its LNG exports relatively stable over the past few years, followed by Malaysia. LNG supply from the US to Asia also increased following an expansion in LNG capacity from 2015, and the US was the fourth largest supplier to Asia in 2023.

<sup>1</sup> Woodside Energy. [Woodside to sell 10% Scarborough interest to LNG Japan](#). 8 August 2023. Page 1.

Figure 2: LNG imports to Japan, China, South Korea and Taiwan by country of origin, MTPA



Source: IEEFA analysis of Kpler LNG data.

Australia’s reliance on Asian LNG demand, and the financial unviability of supplying other regions, means the future of Australia’s LNG sector will rely on sustained demand in the Asian market.

## Anticipated LNG demand growth faces challenges

### Demand forecasts are falling despite industry optimism

Global LNG markets have experienced unprecedented upheaval in recent years following Russia’s invasion of Ukraine and a decline in pipeline gas exports to Europe. European gas buyers turned to LNG markets to replace Russian gas volumes, triggering global competition for LNG cargoes that threatened global energy security and saw prices reach record levels.

A range of governments in Europe responded to the energy crisis by implementing new measures to lower gas demand, including support for energy efficiency measures, electrification of winter heating load, and investment in additional wind and solar capacity.<sup>2</sup> Europe also saw reduced industrial gas demand due to high prices, though it is unclear whether this is transitory. Other countries saw state-owned utilities incur significant losses on the back of high LNG prices and, in the case of Pakistan, rolling blackouts due to insufficient LNG supply.

<sup>2</sup> IEA. [Europe’s energy crisis: What factors drove the record fall in natural gas demand in 2022?](#) 14 March 2023.

Global LNG markets are now experiencing a structural change, with demand in established markets declining and shifting, to some extent, to emerging markets. However, there remains considerable uncertainty about future LNG demand growth in emerging markets.

Shell, in its most recent LNG outlook report, forecast that LNG demand would grow to more than 600MTPA<sup>3</sup> While this forecast growth is lower than that in its<sup>4</sup>

Similarly, BP's 2023 Energy Outlook anticipates that global gas demand will increase into the early 2030s under two of the scenarios modelled, largely driven by rising demand in emerging markets and coal-to-gas switching in China.<sup>5</sup> Under a *Net Zero* scenario, gas demand is forecast to peak around 2025, but under the *New Momentum* scenario, BP forecasts that global gas demand will grow into the 2040s.

BP further anticipates that LNG demand will increase to 2030 under all scenarios, and global LNG demand is forecast to peak above 600MTPA even under the *Net Zero* <sup>6</sup> As noted by BP, the “range of the difference in global gas demand in 2050 across the three scenarios ... [highlights] the sensitivity of natural gas to the speed of the energy transition”<sup>7</sup>

These industry forecasts do not align, however, with forecasts from the International Energy Agency (IEA). In its *World Energy Outlook 2023*, the IEA forecasts gas demand will peak before 2030 under the three scenarios it models.<sup>8</sup> Even under the most conservative *Stated Policies* scenario (STEPS – aligned with 2.4°C warming), gas demand is expected to peak by 2030, and slowly decline thereafter.<sup>9</sup> Demand is anticipated to fall much more quickly under the IEA's *Net Zero Emissions* (NZE – aligned with about 1.5°C of warming) and *Announced Pledges* (APS – aligned with about 1.7°C of warming) scenarios.<sup>10</sup> Notably, gas demand in emerging markets and developing economies is forecast to fall from 2030 under the NZE and APS scenarios.

Lower-than-anticipated demand presents obvious financial risks for LNG producers and exporters. The IEA notes that around two thirds of projects under construction will not fully recover their capital costs under the APS, with this rising to three quarters under NZE.

The IEA's forecasts in recent years highlight the uncertainty over demand. Specifically, demand forecasts have consistently declined since 2019 (Figure 3), most significantly in 2022 reflecting the impact of Russia's invasion of Ukraine. The additional decline in the 2023 outlook largely reflects a more positive outlook for solar and wind generation capacity growth – the IEA has consistently increased its forecasts of new solar and wind generation over the past five years.

<sup>3</sup> Shell. [Shell LNG Outlook 2024](#). February 2024. Page 27.

<sup>4</sup> Ibid. Page 3.

<sup>5</sup> BP. [Energy Outlook, 2023 Edition](#). July 2023. Page 48.

<sup>6</sup> Ibid. Page 50.

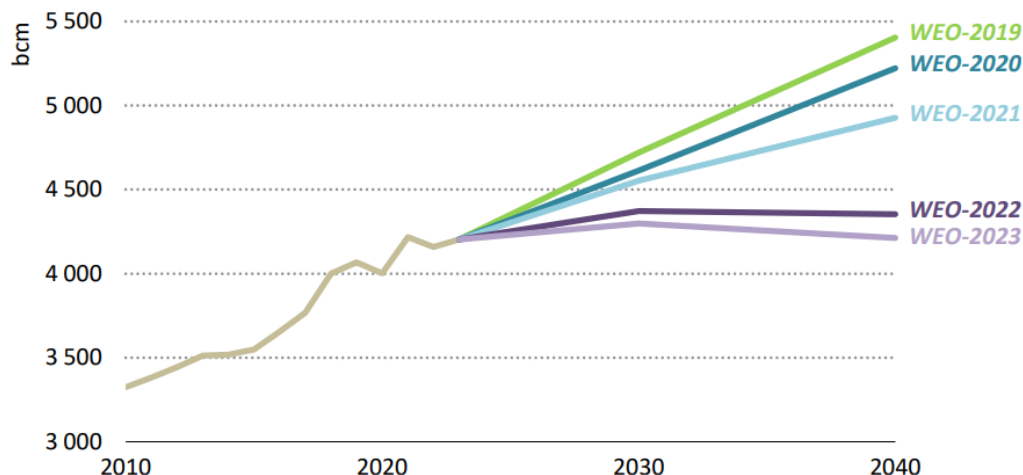
<sup>7</sup> Ibid. Page 49.

<sup>8</sup> IEA. [World Energy Outlook 2023](#). October 2023. Page 30.

<sup>9</sup> Ibid. Page 136.

<sup>10</sup> Ibid. Page 136. The Announced Pledges Scenario is intended to demonstrate possible emissions reductions under targets announced by countries (such as net zero targets). It implicitly assumes that targets are met on time.

**Figure 3: Natural gas demand projections in the STEPS to 2040 in five editions of the IEA's World Energy Outlook (WEO), bcm**



Source: IEA.<sup>11</sup>

While the different forecasts rely on different assumptions, they are aligned on emerging markets being the key driver for any new LNG demand growth.

However, industry forecasts are much more bullish on the prospects of rising LNG demand in emerging markets. As noted in both Shell and BP's outlooks, this reflects assumptions about the use of gas by industries and coal-to-gas switching for electricity generation in emerging markets.

Shell's forecast may also reflect its activities to create and lock in demand growth in emerging markets. The Australasian Centre for Corporate Responsibility (ACCR) recently undertook a review of Shell's disclosure of its lobbying activities.<sup>12</sup> It "identified multiple examples of undisclosed lobbying by Shell and its industry associations in emerging markets", to:

- "expand and create markets for gas in India
- "build long-term LNG demand in Southeast Asia, and
- "oppose the transition away from fossil fuels in China, Mexico and South Africa."

To the extent that Shell's forecasts incorporate assumptions about the impact of its lobbying activities, the forecasts may be subject to downside demand risks if these lobbying efforts do not lead to sustained increases in gas and LNG demand.

<sup>11</sup> IEA. [World Energy Outlook 2023](#). October 2023. Page 77.

<sup>12</sup> ACCR. [In the dark: gaps in Shell's climate lobbying disclosures](#). 1 March 2024. Page 4.

## Mature LNG markets seeing declines in LNG demand

LNG demand in the mature markets of Japan, South Korea and Europe, which account for about half of the world's LNG demand, is declining for a number of reasons.

**Japan**, one of the world's largest LNG importers, saw LNG imports grow rapidly in the aftermath of the 2011 Fukushima nuclear disaster as electricity generators sought alternative generation fuels (due to Japan shutting down all of its nuclear generators).<sup>13</sup> LNG demand subsequently peaked in 2014 and has been in decline since due to the restart of some of Japan's nuclear reactors and greater penetration of renewable energy generation.

As previously noted by IEEFA: "Japan's LNG imports fell 8% in 2023 to their lowest levels since 2009 (67MTPA). This was primarily due to lower demand in the power sector, where rising nuclear availability, declining power demand, and higher generation from renewable resources reduced the call on gas-fired generation."<sup>14</sup>

Japan's future LNG demand is estimated to fall even further due to the country's climate goals (reflected in the Sixth Strategic Energy Plan, growth in renewables and the restart of more nuclear generators). IEEFA previously estimated that Japan's LNG demand could fall to less than 50MTPA by 2030.<sup>15</sup>

Declining LNG demand in Japan has resulted in the four largest Japanese LNG buyers having surplus contracted LNG volumes, with these companies now seeking to cultivate demand in Asian markets (primarily South and Southeast Asia) to be able to offload excess LNG – as explored later in this report.<sup>16</sup>

**South Korea** similarly saw LNG imports decline in 2023, with imports down by 4.9% relative to 2022. This was due to elevated LNG prices in 2023, with high prices over the past three years leading to state-owned utility Korea Electric Power Corporation losing More than KRW44 trillion.<sup>17</sup>

The South Korean Government's *15<sup>th</sup> Long-Term Natural Gas Supply and Demand Plan* signalled declining future gas consumption that is likely to continue this trend of falling LNG demand. Specifically, the new plan anticipates a much smaller role for gas in the country's future electricity grid and the government has announced plans to increase the share of renewable and nuclear generation in South Korea, with LNG generation projected to fall from almost 23MTPA in 2023 to just over 11MTPA.<sup>18</sup>

**Europe's** LNG demand is expected by IEEFA to peak in 2025, before falling by 11% to 2030.<sup>19</sup> The EU Agency for the Cooperation of Energy Regulators (ACER), in contrast, anticipates LNG demand to peak this year.

<sup>13</sup> IEEFA. [Japan's largest LNG buyers have a surplus problem](#). 11 March 2024. Page 7.

<sup>14</sup> IEEFA. [Global LNG Outlook 2024-28](#). 25 April 2024. Page 27-28.

<sup>15</sup> Ibid. Page 28.

<sup>16</sup> IEEFA. [Japan's largest LNG buyers have a surplus problem](#). 11 March 2024. Page 16.

<sup>17</sup> Yonhap infomax. [KEPCO, 2 trillion net profits in Q3 after hiking power tariffs, additional hikes needed](#). 11 December 2023.

<sup>18</sup> IEEFA. [Global LNG outlook 2024-28](#). April 2024. Page 29.

<sup>19</sup> IEEFA. [Global LNG Outlook 2024-28](#). 25 April 2024. Page 24.



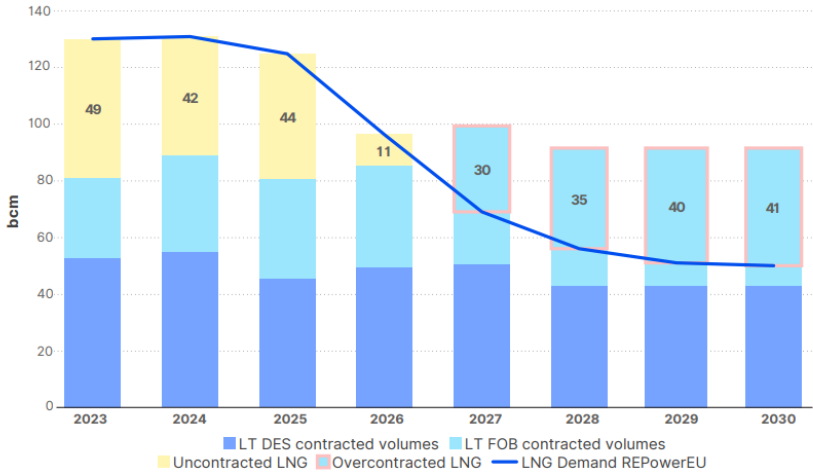
Following the Russian invasion of Ukraine, European gas buyers turned to LNG markets to replace Russian pipeline gas supply. This, in turn, created intense competition for LNG cargoes and pushed LNG prices to never before seen levels. Energy security concerns prompted a rush of new LNG contracting, investments in new LNG import terminals in Europe, and mandated minimum gas storage requirements.

The energy crisis also led to European governments adopting the RePowerEU plan, which resulted in coordinated actions to lower gas demand, increase renewables and diversify supply (to reduce reliance on Russian pipeline gas).<sup>20</sup> This is driving a structural shift in Europe’s energy markets, which could see gas demand fall significantly in coming years. As IEEFA recently noted:

“IEEFA expects that declining overall gas demand in Europe through 2030 is likely to reduce LNG imports after a peak by 2025. Already, the addition of new import infrastructure in 2023 caused utilization rates of EU LNG terminals to decline to 58.5% from 63% in 2022. An additional 94 bcm [billion cubic metres] of proposed import projects could bring Europe’s total regasification capacity to 405 bcm by 2030. As a result, the continent’s ongoing buildout of import terminals could cause utilization rates to fall over the remainder of the decade.”<sup>21</sup>

A recent report from ACER estimated future gas demand, and LNG requirements, under two scenarios: the Fit for 55 legislative package; and the REPowerEU reforms (which are additional to the Fit for 55 reforms). ACER forecast that if the REPowerEU targets are realised, European gas demand could decline by just over 200bcm by 2030 (relative to 2019).<sup>22</sup> The resulting decrease in LNG demand would leave European LNG buyers facing a surplus of LNG supply (Figure 4), which would be expected to be sold into other markets. This could further add to a coming glut in LNG markets.

**Figure 4: European LNG demand under the REPowerEU scenario by 2030, bcm**



Source: ACER.<sup>23</sup>

<sup>20</sup> European Commission. [REPowerEU at a glance](#). Accessed 29 April 2024.  
<sup>21</sup> IEEFA. [Global LNG Outlook 2024-28](#). 25 April 2024. Page 27.  
<sup>22</sup> ACER. [Analysis of the European LNG market developments: 2024 Market Monitoring Report](#). 19 April 2024. Page 7.  
<sup>23</sup> Ibid. Page 8.

## Challenges to structural demand growth in emerging markets

The future of LNG markets, and whether there will be sufficient new demand to replace declining demand in mature markets and absorb the unprecedented wave of new supply, depends on demand growth in emerging markets, primarily in Asia and South Asia.

However, despite optimistic forecasts, structural LNG demand growth in emerging markets faces a range of barriers, competition from renewables and other energy sources (primarily coal), and uncertainty over future demand. As noted by the IEA, "... uncertainty remains surrounding LNG demand growth in emerging Asian gas markets as affordability and market stability continue to be key factors in the take-up of natural gas in certain sectors and countries."<sup>24</sup>

**China's** LNG exports have boomed over the past decade, with China recently overtaking Japan to become the world's largest LNG importer.<sup>25</sup> China is also expected to be the key driver of gas demand growth in coming decades. Shell's 2024 LNG Outlook anticipates that China's gas demand will grow by more than 250bcm between 2023 and 2040 (to just over 650bcm), materially larger than the expected growth of South and Southeast Asia combined.<sup>26</sup> This growth primarily stems from higher forecast gas demand for industry, residential and commercial use, and for power generation.<sup>27</sup>

In contrast, the IEA's *World Energy Outlook 2023* forecast China's total gas demand at 458bcm and 452bcm in 2030 and 2050 respectively (compared to 369bcm in 2022), with the period between seeing relatively stable gas demand.<sup>28</sup> The IEA further noted that uncertainty about China's future economic growth contributes to a related uncertainty about future gas demand. To account for this uncertainty, the IEA modelled different scenarios to assess the impact of different assumptions about future economic growth on gas and LNG demand. This modelling suggests that gas demand could be up to 30bcm lower in 2030 (under a lower economic growth STEPS scenario), equivalent to about 23MTPA (or 20% of China's expected LNG imports in 2030).

In a draft version of the National Gas Utilisation Policy, China's Government signalled a shift in the role of gas in China, moving from a focus on increased gas consumption to now prioritising "orderly growth in natural gas demand".<sup>29</sup> The draft also highlights the need for demand management and a "less indiscriminate gas-fired power build out".<sup>30</sup>

LNG imports in China are likely to face stiff competition from domestic gas production, pipeline imports, coal and renewables. In 2023, China rolled out about 300 gigawatts (GW) of renewable generation capacity, 216GW of which was new solar photovoltaic (PV) generation capacity (equal to 14% of the world's total solar PV capacity).<sup>31</sup> This investment has continued into 2024, with China

<sup>24</sup> IEA. [Natural Gas Supply Security in Korea](#). April 2024. Page 22.

<sup>25</sup> IEEFA analysis of Kpler data.

<sup>26</sup> Shell. [Shell LNG Outlook 2024](#). February 2024. Page 6.

<sup>27</sup> Ibid. Page 30.

<sup>28</sup> IEA. [World Energy Outlook 2023](#). October 2023. Pages 285 and 236.

<sup>29</sup> IEA. [Gas Market Report, Q1-2024](#). January 2024. Page 20.

<sup>30</sup> Ibid.

<sup>31</sup> S&P Global Commodity Insights. [Infographic: China's solar capacity growth in 2023 sets new record](#). 8 February 2024.

adding almost 46GW of new solar PV capacity in just the first quarter of 2024 (a 35% increase relative to new solar additions in the first quarter of 2023).<sup>32</sup>

Slowing economic growth could also weigh on China's gas demand. Under a low economic growth and gas demand scenario, the IEA anticipates that China could have up to 80bcm (about 59MTPA)<sup>33</sup>

**India, Bangladesh and Pakistan** all saw LNG imports decline in 2022 due to prices being unsustainably high, underscoring the price sensitivity of LNG buyers in South Asia. Nonetheless, both India and Bangladesh are looking to increase LNG imports, with the Bangladeshi Government recently approving construction of the country's third LNG import terminal, and the Indian Government setting a target to increase gas consumption by nearly 90MTPA by 2030 (an increase of about 270%).

However, future sustained LNG demand growth in South Asia could be adversely impacted by LNG price volatility and fiscal challenges.<sup>34</sup> High LNG prices in 2022 increased Bangladesh's import costs, with USD5 billion remaining outstanding, and concerns about Pakistan's credit risk have prompted LNG suppliers to demand premiums even for spot LNG cargoes.<sup>35</sup>

There is also limited upside for gas generation in South Asia, due to high prices and increased competition from renewable and nuclear generation. Both Pakistan and India have signalled their intent to not build any new gas generation.

Gas demand growth for industrial applications also faces headwinds. As noted previously by IEEFA, "... gas usage in the fertilizer sector [in India] could increasingly compete with hydrogen technologies, which are being piloted at scale. About 5.8MTPA of green ammonia capacity is under construction, with first production likely in 2027.<sup>36</sup>

High LNG prices continue to present challenges in **Southeast Asia**, particularly in **Vietnam** and the **Philippines**, with both countries facing exposure to high LNG spot prices due to neither country having any long-term LNG contracts in place.

Across the region, the impact of high and volatile LNG prices on state-owned utilities have "added financial and political pressure to find alternative energy sources, including renewables and domestic gas."<sup>37</sup> In 2023, **Thailand** finalised a procurement process for 5GW of new renewable generation and **Singapore** conditionally approved a range of new renewable import agreements from neighbouring countries.

Gas demand for generation also faces a constrained role due to delays to power purchase agreements for LNG-to-power projects and a pivot to cheaper alternatives.<sup>38</sup>

<sup>32</sup> PV Tech. [China adds 45.7 GW of solar PV in Q1 2024, up from 33.7GW in q1 2023](#). 22 April 2024.

<sup>33</sup> IEA. [World Energy Outlook 2023](#). October 2023. Page 238.

<sup>34</sup> IEEFA. [Global LNG Outlook 2024-28](#). 25 April 2024. Pages 35-36.

<sup>35</sup> Ibid. Page 36.

<sup>36</sup> Ibid. Page 37.

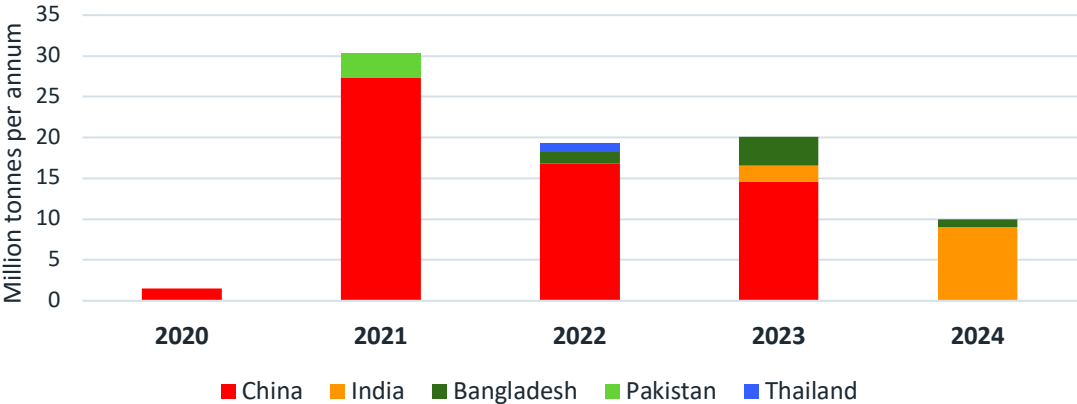
<sup>37</sup> IEEFA. [Global LNG Outlook 2024-28](#). 25 April 2024. Page 40.

<sup>38</sup> Ibid. Page 40.

Despite these barriers, industry forecasts anticipate large increases in LNG demand in emerging countries in Asia. For example, BP’s 2023 Energy Outlook anticipates that demand in China, India and other emerging Asian nations will increase by about 200MTPA <sup>39</sup>

However, IEEFA estimates that these countries have entered into only about 80MTPA worth of new LNG SPAs (Figure 5), well below BP’s estimated increase of about 200MTPA by 2030.

**Figure 5: New LNG SPAs for emerging Asia, by year of signing, MTPA**



Source: ICIS

Further, the largest LNG SPA signed by India in recent years, Petronet’s recent 7.5MTPA LNG SPA with Qatar, is an extension of two existing LNG SPAs (due to expire in early 2028) rather than an addition to India’s current LNG supply. This low level of contracting raises questions about whether India will meet a government target to increase gas consumption by 90MTPA by 2030 (anticipated to be primarily met through LNG imports).

Notably, Vietnam and the Philippines, both seen as future markets for LNG-to-power, have not signed any firm LNG SPAs.<sup>40,41</sup>

The lack of material firm contracting (outside China) raises questions about future demand forecasts in emerging markets. This is particularly the case given the risks of LNG spot market exposure, which in recent years has resulted in state-owned utilities across the emerging world incurring significant financial hits due to high LNG spot prices and an inability to pass on increased costs to their domestic consumers.

Recent geopolitical tensions in the Middle East serve as a reminder of these risks, with market commentary noting that LNG spot prices could again reach record levels if the Strait of Hormuz was closed to marine traffic. However, despite the risks, emerging market buyers are yet to contract significant new volumes (again, with the exception of China).

<sup>39</sup> BP. [Energy Outlook, 2023 Edition](#). July 2023.

<sup>40</sup> Fitch Solutions. [Philippines Emerging As A New Frontier LNG Market](#). 22 December 2023.

<sup>41</sup> Lexology. [The continuing evolution of the Asian LNG market](#). December 2023.

# Australian LNG is facing increasing competition

Australian LNG exporters will face increasing competition in LNG markets due to a massive wave of new LNG supply (a significant portion of which remains uncontracted) and the expiry of existing Australian LNG contracts. New supply is likely to push down prices in LNG spot markets but could also see prices in new LNG contracts fall.

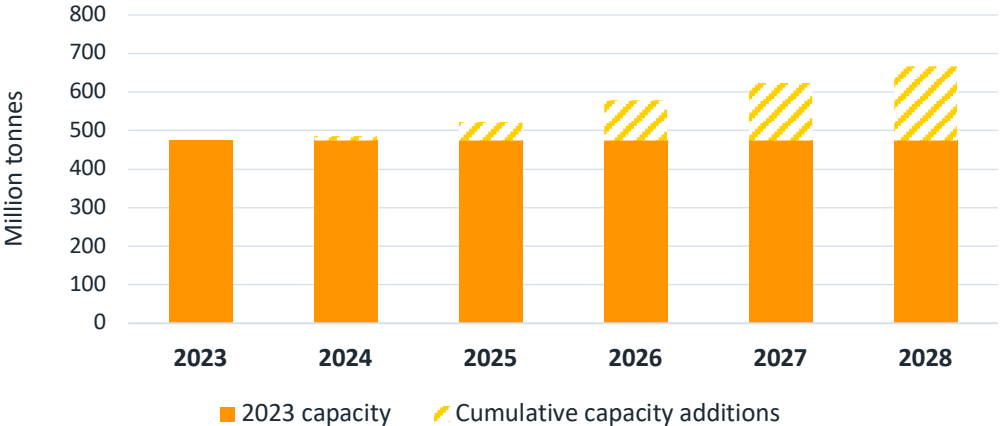
## Booming low-cost LNG supply will create an LNG glut

In its *Global LNG Outlook 2023-27*, IEEFA predicted that global LNG markets would see a glut in the second half of the decade.<sup>42</sup> The IEA has since confirmed this view.<sup>43</sup>

IEEFA expects that about 181 million tonnes (Mt) of new LNG liquefaction capacity will come online in the period from late 2024 to 2028 (Figure 6), equivalent to about 40% of global LNG capacity in 2023. This is by far the largest addition to global liquefaction capacity in the history of LNG markets, surpassing the previous record by more than 60MTPA. It’s also occurring at a time when the IEA has said that the ‘golden age’ of gas is over and there is considerable uncertainty about future demand.

This new supply is split across five regions, with the US and Qatar driving the largest capacity additions. In the US, five new projects are expected to bring 71MTPA of new supply to market, with Qatar aiming to add 48MTPA by 2028 (with an additional 16MTPA by 2030). Russian and Canadian projects aim to add 34MTPA of capacity. Finally, there are five new projects in Africa that are expected to add 14MTPA of capacity.<sup>44</sup>

**Figure 6: Global LNG liquefaction capacity, Mt**



Source: IEEFA estimates, based on data from the International Gas Union, the International Group of Liquefied Natural Gas Importers, Independent Commodity Intelligence Services, Kpler, Global Energy Monitor, company announcements and financial filings, and news reports.

<sup>42</sup> IEEFA. [Global LNG Outlook 2023-27](#). 15 February 2018.  
<sup>43</sup> IEA. [World Energy Outlook 2023](#). October 2023. Page 21.  
<sup>44</sup> IEEFA. [Global LNG Outlook 2024-28](#). 25 April 2024. Pages 9-10.

Australian LNG capacity will also increase through the sanctioning of Woodside's Pluto 2 train (5MTPA) and debottlenecking work at Inpex's Ichthys plant (0.4MTPA).

In January 2024, the US Government announced a temporary pause on pending approvals for new LNG exports to countries without a free trade agreement with the US.<sup>45</sup> This pause is intended to allow the Department of Energy to update the economic and environmental analyses that underpin export approvals. While the pause will not impact on projects that have already received approvals, it has raised concerns about the impact on proposed LNG projects that have not yet been approved. The US Secretary of Energy, however, recently indicated the pause would be relatively short-lived.<sup>46</sup>

## Australia has higher costs than its key competitor Qatar

The rapid expansion in new global LNG capacity from 2025 includes 64MTPA of new supply from Qatar, which, given its location, is a key competitor for Australian LNG exporters (particularly for supply into South and Southeast Asia). Qatar is also the world's lowest-cost LNG producer, for both capital costs and for ongoing marginal gas production and liquefaction costs.

In contrast, Australia's LNG sector has historically had high capital costs for new LNG plants, and when accounting for all costs involved in producing LNG, Australian projects generally had much higher costs relative to key competitors.<sup>47</sup> As noted by Wood Mackenzie, "... Australia sits relatively high up along the global LNG cost curve in relation to other major LNG producing nations."<sup>48</sup>

LNG capital costs have increased in the intervening years, including for US and Qatari projects.<sup>49</sup> Nonetheless, IEEFA expects that new Australian LNG projects are likely to continue to face higher costs than projects in either the US or Qatar.

Australia's high costs have an impact on LNG project investment returns. A recent report by the ACCR found that while Australia's LNG growth wave led to Australia being the world's largest exporter, it did not deliver value for shareholders, with capital cost overruns and production delays leading to seven of the eight Australian LNG plants that came online between 2012 and 2017 eroding shareholder value (with returns below the cost of capital).<sup>50</sup> The ACCR further found that these projects appear to have eroded USD19 billion of shareholder value.

<sup>45</sup> The White House. [Fact Sheet: Biden-Harris Administration Announces Temporary Pause on Pending Approvals of Liquefied Natural Gas Exports](#). January 2024.

<sup>46</sup> CNBC. [U.S. energy secretary tells skeptical executives natural gas export pause will be short-lived](#). 21 March 2024.

<sup>47</sup> IOP Conference Series: Earth and Environmental Science. [Global LNG market: supply-demand and economic analysis](#). 2022. Page 5. *Qian Zou et al.*

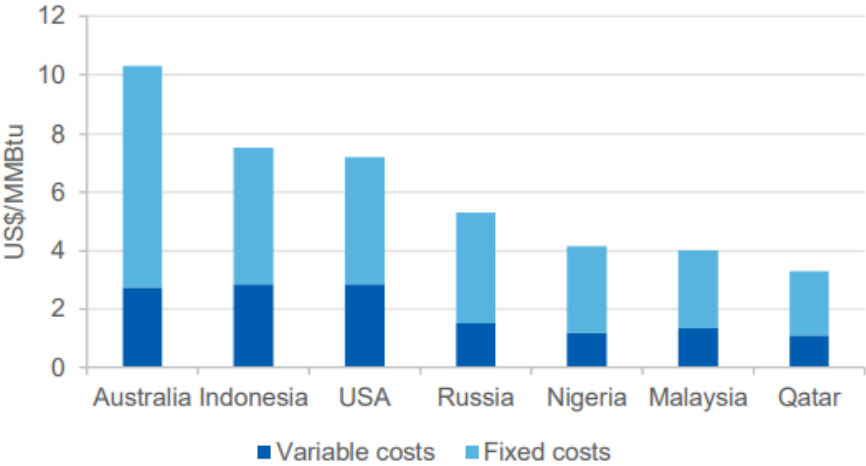
<sup>48</sup> Wood Mackenzie. [Australia Oil & Gas Industry Outlook Report](#). March 2020. Page 16.

<sup>49</sup> Wood Mackenzie. [Positioning for global LNG's next big growth phase](#). July 2023.

<sup>50</sup> ACCR. [Australia's LNG growth wave – did it wash for shareholders?](#) November 2023. Pages 3-4.



Figure 7: LNG project costs, USD/Million Metric British Thermal Units (\$/MMBtu)



Source: Department of Industry, Science and Resources.<sup>51</sup>

The high capital cost of Australian LNG raises questions about the financial viability of any new greenfield LNG plants being built in Australia, despite plans by junior explorer Tamboran Resources to develop the NTLNG project in Darwin (with the support of government subsidies and land grants). Cost overruns at existing Australian LNG projects have led to Australia having a reputation as a high-cost region, which in IEEFA’s opinion could make it more difficult for any new LNG projects to attract sufficient investment to reach FID.<sup>52</sup> IEEFA recently estimated that NTLNG could face capital costs of AUD10-15 billion just for the liquefaction facility, based on an estimated cost of USD6-9/MMBtu.

This is consistent with the Government’s findings in the Future Gas Strategy, which finds that “established Australian production is able to be more competitive than prospect new sites.”<sup>53</sup>

Existing Australian LNG projects may also face higher upstream gas development costs than key competitors. Wood Mackenzie previously estimated Qatar’s upstream development costs for its LNG expansion at below USD2/MMBtu.<sup>54</sup> Australia’s Commonwealth Scientific and Industrial Research Organisation (CSIRO) found that the costs of onshore drilling in Australia are more than 2.5 times higher than in the US.<sup>55</sup>

More generally, Wood Mackenzie noted that: “... the increasing complexity of extraction and remoteness of resources could feasibly drive up the cost of upstream gas. As the example of cost escalation in the last wave of Australian LNG shows, the external environment is variable, difficult to forecast, and ultimately shifts value perceptions back and forth between upstream and downstream over any projected period. Australia’s high-cost labour, often geographical remoteness of its infrastructure, and extreme weather-related events will continue to impact the risk profile of future

<sup>51</sup> Department of Industry, Science and Resources. [Future Gas Strategy Analytical Report](#). May 2024. Page 62.  
<sup>52</sup> Oxford Institute for Energy Studies. [LNG Plant Cost Reduction 2014-18](#). October 2018. Page 16.  
<sup>53</sup> Department of Industry, Science and Resources. [Future Gas Strategy Analytical Report](#). May 2024. Page 62.  
<sup>54</sup> Wood Mackenzie. [Australia Oil & Gas Industry Outlook Report](#). March 2020. Page 17.  
<sup>55</sup> Ibid. Page 16.

and existing downstream, and underutilised LNG capacity (i.e., both currently and threatened in the future) would increase downstream unit costs.”<sup>56</sup>

The Waitsia project in onshore Western Australia (WA) provides a recent example of the potential for cost overruns for Australian gas projects. The project, a joint venture between Japanese trading house Mitsui and Beach Energy, saw its total development costs increase to AUD1.3 billion from an original estimate of between AUD700-800 million, an increase of up to 85%.<sup>57</sup>

In contrast, by some estimates, Qatar’s marginal LNG costs may actually be negative in periods of high oil prices due to the co-production of oil. For example, the Oil & Gas Journal reported in 2021 that: “Qatargas 1 LNG Train 1 has an estimated variable cost of LNG production of \$1.6/MMbtu. If the pre-tax liquids revenue from the oil production is considered, the costs are offset by oil revenues of about \$2.6/MMbtu, which brings net costs down to a negative \$1/MMbtu. That way, projects like Qatargas 1 LNG Train 1 would cover their costs even if LNG prices went down to zero.”<sup>58</sup>

Gas development and drilling costs could also increase as LNG exporters shift from more prosperous to more marginal gas fields. CSIRO found that drilling costs for the North West Shelf project increased by a factor of more than 11 over the decade to 2013.<sup>59</sup>

Wood Mackenzie, in assessing the risks of periods of low LNG prices, noted that three Queensland LNG projects “have high ongoing drilling costs required to maintain production levels”, and that the breakeven price for undeveloped Queensland Coal Seam Gas fields was at the high end for global LNG short-run marginal costs (for LNG delivered to Japan).<sup>60</sup> This could mean higher costs as existing gas fields decline and producers move to less prospective fields.

Australian LNG exporters, however, have lower LNG freight costs for cargoes delivered into the key Asian markets, relative to most LNG exporters outside Asia, due to shorter shipping distances (Table 1). While US projects have lower capital costs, and potentially lower ongoing gas costs (depending on future pricing at the Henry Hub<sup>61</sup>), they face higher costs than Australian projects for delivery into Asia. This may mean that US LNG is more expensive (on a short-run marginal cost basis), particularly during periods of high LNG freight rates.

<sup>56</sup> Ibid. Page 17.

<sup>57</sup> AFR. [Beach shares dive as Waitsia gas project costs blow out to \\$1.3b](#), 8 April 2024.

<sup>58</sup> Oil & Gas Journal. [Rystad: US producers' cost to supply LNG to Asia increases](#), 24 June 2021.

<sup>59</sup> Wood Mackenzie. [Australia Oil & Gas Industry Outlook Report](#), March 2020, Page 16.

<sup>60</sup> Wood Mackenzie. [The LNG wars – Will short run marginal costs be the deciding factor?](#) 16 May 2017.

<sup>61</sup> The Henry Hub is a physical gas trading location in the US. Some LNG producers source gas directly from this Hub at prevailing market prices.

**Table 1: LNG shipping distances and freight costs to North Asia**

Loading port	Receiving terminal	Distance (nautical miles)	Estimated freight cost (USD/MMBtu)
Australia (Barrow Island)	Tokyo	3,727	0.33
	Shanghai	3,322	0.29
Qatar	Tokyo	6,512	0.52
	Shanghai	5,845	0.46
US (Sabine Pass)	Tokyo (via Panama Canal)	9,209	0.89
	Shanghai (via Panama Canal)	10,081	0.93

Source: Oxford Institute for Energy Studies.<sup>62</sup> LNG freight rate estimates are from ICIS LNGEdge (31 May 2024).

## Carbon capture and storage will add to Australian project costs

The global LNG industry is facing increasing pressure to decarbonise in light of increasing scrutiny on the carbon intensity of LNG compared with renewable energy sources, and emissions reduction targets in a range of countries.<sup>63,64,65</sup>

In an Australian context, LNG exporters and gas developers are required to lower their greenhouse gas emissions under Australia's revised Safeguard Mechanism (provided they fall within scope of the mechanism's coverage). The mechanism applies to major industrial facilities that emit more than 100,000 tonnes of CO<sub>2</sub>e in a year and requires these facilities to ensure their net emissions are below a prescribed baseline (which declines over time).<sup>66</sup> For new gas fields, operators are required under the mechanism "to have net-zero scope 1 emissions from the outset". Put differently, operators are required to offset any reservoir CO<sub>2</sub> emissions for any new gas fields and may be required to offset any methane leakages (if it results in their CO<sub>2</sub>e emissions being above their baseline).

The Scarborough gas field in offshore WA, which is being developed to provide feedgas for Woodside's Pluto LNG facility, has low CO<sub>2</sub> (at about 0.5%). However, several proposed new gas field developments, intended to backfill existing LNG plants, have much higher CO<sub>2</sub> concentrations, which is likely to add to the costs of developing these fields.

Santos' Barossa field, which is currently being developed, has a CO<sub>2</sub> content of about 18% and estimated emissions of almost 13Mt of CO<sub>2</sub>e to 2030.<sup>67</sup> IEEFA estimates that if Santos were to offset these emissions solely through the purchase of Australian Carbon Credit Units (ACCUs), it would need to buy about 13-14Mt of offsets by 2030. At a contemporary ACCU price of AUD33.75 (which is

<sup>62</sup> Oxford Institute for Energy Studies. [The LNG Shipping Forecast: costs rebounding, outlook uncertain](#). March 2018. Page 6.

<sup>63</sup> Wood Mackenzie. [Can emissions taxes decarbonise the LNG industry?](#) 11 April 2024.

<sup>64</sup> Herbert Smith Freehills. [Decarbonisation of the LNG Supply Chain: challenges and the way forward](#). 14 January 2021.

<sup>65</sup> McKinsey. [The impact of decarbonization on the gas and LNG industry](#). 30 June 2021.

<sup>66</sup> King, Wood and Mallesons. [The Safeguard Mechanism is now law – Here's your to-do list for Australia's new carbon rules](#). 8 August 2023.

<sup>67</sup> S&P Global Commodity Insights. [Ambitious CCS project may dent strong ACCU demand expected from Santos' Barossa gas field](#). 9 April 2024.

broadly in the range of prices over the period from July 2022 to September 2023), this would cost Santos an estimated AUD438-472 million.<sup>68,69</sup>

Santos has proposed development of a new carbon capture and storage (CCS) facility at the now-depleted Bayu Undan field (which previously supplied the Darwin LNG facility) to capture emissions from the Barossa field (as well as Scope 3 emissions imported from other countries). The costs associated with this project, however, are also likely to be material. Energy consultancy Rystad estimates capital costs of more than USD1.7 billion, equating to a cost of about USD60-70 per tonne for the entire project (though this may include transport costs for CO<sub>2</sub> transported to Australia from other countries).<sup>70</sup>

Internal Santos documents also indicate that Santos expects the project cost to exceed USD1.6 billion. This is significantly lower than the estimated cost for Gorgon CCS of more than AUD3 billion despite Bayu Undan CCS potentially having an annual injection capacity of more than double the Gorgon project.<sup>71,72</sup>

CCS also has a poor track record, with the majority of large projects to date either failing or underperforming capture targets.<sup>73</sup> As previously noted by IEEFA: “In Australia, the Gorgon CCS project has failed to deliver, underperforming its targets for the first five years by about 50%. In FY2022-23, it injected just 34% of the 5 million tonnes of CO<sub>2</sub> (MtCO<sub>2</sub>) it captured. The Gorgon partners have spent more than A\$3 billion on the CCS facility since it started seven years ago. Globally, the maximum capture rate achieved by CCS to date appears to be 83%, well below the 90%-95% presented as feasible by the oil and gas industry.”

Several other LNG exporters could face material abatement costs if they proceed with plans to develop high-CO<sub>2</sub> fields, including:

- Woodside’s Browse field, which has an average reservoir CO<sub>2</sub> content of about 10%.
- Inpex’s Plover field, intended to backfill Ichthys LNG, which has a reservoir CO<sub>2</sub> content of about 17%.

Woodside has proposed developing a new CCS facility to capture emissions from the Browse field, with company plans indicating that the CCS project would reduce Scope 1 emissions by about 53Mt of CO<sub>2</sub>e (equivalent to a 47% reduction), which would leave a residual of about 59Mt of CO<sub>2</sub>e that would need to be offset (assuming emission capture targets were met).

Under Australian law, these companies may face a 15-year period of ongoing liability for any leakages of CO<sub>2</sub> from CCS facilities, which may require them making provisions to cover unanticipated liabilities.

<sup>68</sup> The closing price for generic ACCUs on 1 May 2024 was AUD33.75.

<sup>69</sup> Clean Energy Regulator. [Quarterly Carbon Market Report data workbook \(September 2023\)](#). September 2023.

<sup>70</sup> Energy Voice. [Santos eyes cheaper carbon storage offshore East Timor at new \\$1.7bn APAC hub](#). 27 May 2022.

<sup>71</sup> Santos. [MOUs executed for potential CO2 supply to underpin Santos’ Bayu-Undan CCS project](#). 3 May 2023.

<sup>72</sup> Department of Energy, Mines, Industry Regulation and Safety. [Gorgon carbon dioxide injection project](#).

<sup>73</sup> IEEFA. [Fact Sheet: Carbon Capture and Storage \(CCS\) has a poor track record](#). 8 February 2024.

## Australian exporters will face increasing competition in LNG contract and spot markets

The looming wave of new LNG supply is likely to increase the level of competition faced by Australian LNG producers.

In the next few years, this is likely to be most evident in spot markets, with LNG spot prices almost certain to fall due to the looming glut. In the longer term, Australian LNG exporters could find it more difficult to secure firm LNG SPAs, to replace expiring SPAs, if there continues to be large volumes of uncontracted LNG available.



**The looming wave of new LNG supply is likely to increase the level of competition faced by Australian LNG producers.**

The majority of Australia's LNG export capacity is currently allocated under long-term LNG SPAs, typically with foundation customers (i.e. customers who entered into LNG SPAs prior to LNG projects commencing construction). IEEFA estimates that in 2024, the volume of Australian LNG contracted longterm LNG SPAs totalled- slightly more than 67MTPA.<sup>74</sup> This is equivalent to about 75% of Australia's total capacity of 88.2MTPA (Figure 8).

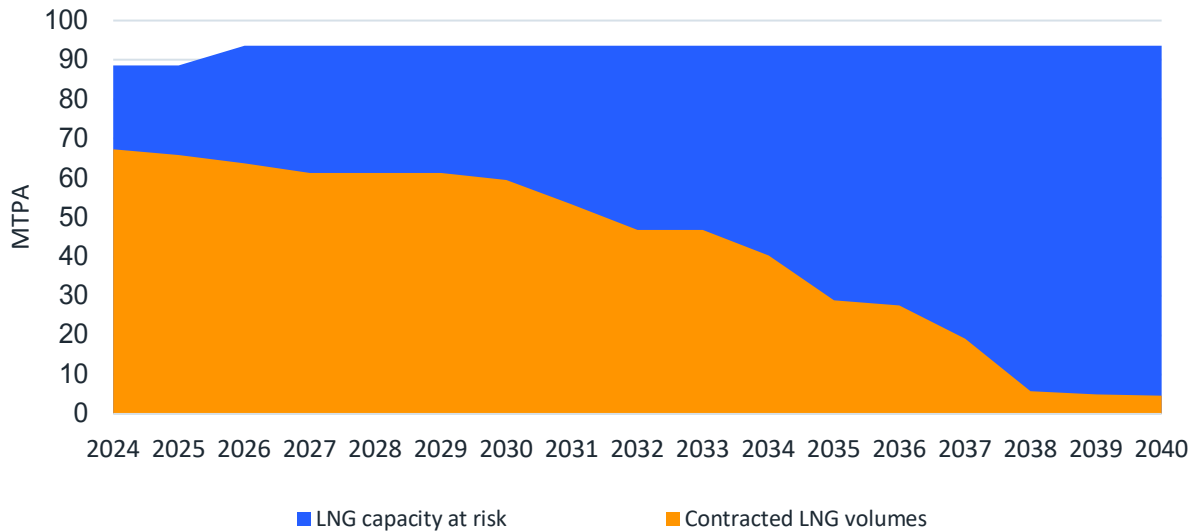
The volume of Australian LNG contracted will fall to just over 61MTPA by 2027, remaining stable until 2029 before sharply declining from 2030. While it is possible that new contracts will be executed, contracted volumes could potentially fall below 41MTPA by 2034 and below 30MTPA by 2035.

Generally speaking, the ability of Australian LNG exporters to sign new deals will depend on buyers being willing to enter into firm LNG contracts and the ability of Australian exporters to compete with any remaining uncontracted LNG. It will also depend on LNG exporters having access to sufficient reserves of gas.

That said, an increasing portion of Australia's LNG liquefaction production from 2030 is likely to either be exposed to LNG spot market pricing or face the risk of ullage/mothballing due to declining gas production or insufficient global demand.

<sup>74</sup> Estimates of the volume of LNG 'effectively' contracted under LNG SPAs.

**Figure 8: Australia’s LNG capacity at risk of ullage or exposure to spot markets, MTPA**

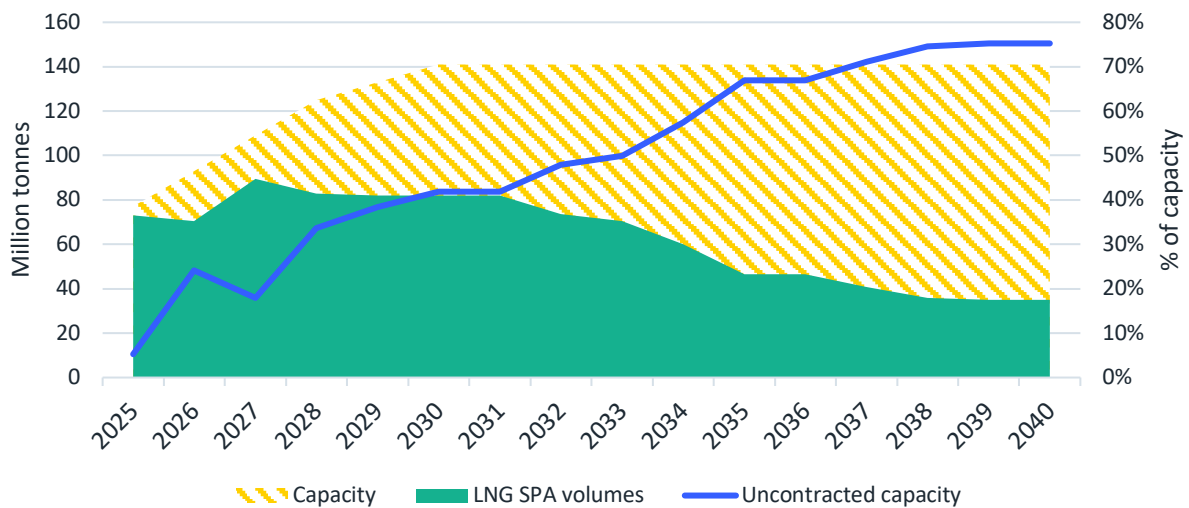


Source: IEEFA estimates based on data from Kpler, ICIS and GIIGNL.

Globally, there has been a rush of LNG contract activity in recent years, spurred by both the shift away from Russian pipeline gas in Europe and the boom in new LNG supply (with firm offtake contracts typically required for project financing).

Despite this, a significant portion of LNG capacity set to come online in the next six years remains uncontracted, particularly from low-cost Qatar (Figure 9). By 2030, when the expiry of Australian LNG contracts starts to pick up pace, Qatar could have up to 59MTPA of uncontracted LNG capacity that, given Qatar’s low costs, would likely outcompete Australian LNG on price.

**Figure 9: Qatar’s uncontracted LNG capacity**



Source: IEEFA estimates using ICIS, Kpler, GIIGNL data.

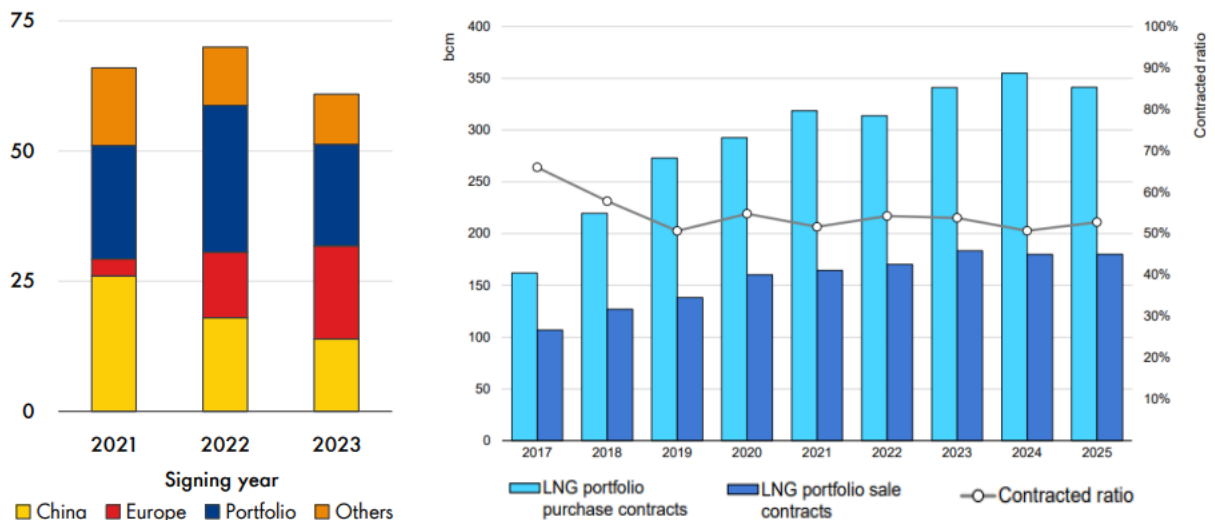


LNG traders, portfolio players and some LNG buyers are also likely to compete with Australian LNG exporters within the Asian region.

The recent surge in contracting has in part been driven by traders and portfolio players, who have secured additional volumes of LNG under firm contracts over the past three years. These portfolio traders now have significant LNG volumes under contract, about half of which they have not yet on-sold to end users, according to the IEA. In effect, LNG traders and portfolio players are taking long positions, exposing them to LNG spot market pricing and the possibility of lower than anticipated future demand (Figure 10). This represents a key financial risk as LNG spot futures have little to no liquidity beyond one to two years, limiting the ability to hedge.

It also means that by 2025, portfolio players could have about 160bcm (about 115Mt) of LNG available to be sold under LNG contracts, adding to the substantial volumes of uncontracted gas.

**Figure 10: LNG portfolio traders have material uncontracted volumes**



Source: Shell, MTPA (LHS);<sup>75</sup> IEA (RHS).<sup>76</sup>

Declining demand in mature markets could also add to the glut of uncontracted LNG. As noted earlier, if the EU meets the targets outlined in the REPowerEU plan, European LNG buyers could have a surplus of 41bcm (29MTPA) of LNG by 2030.

In Japan, government policy intent on protecting Japan’s energy security and influence in the global LNG market in the face of declining domestic demand will add to this surplus. While the past five years have seen Japan’s LNG requirements fall by about 17%, its handling of LNG has grown, fuelling higher resales to third countries.<sup>77</sup> Remarkably, the volume of LNG sold by Japanese

<sup>75</sup> Shell. [Shell LNG Outlook 2024](#). February 2024. Page 34.

<sup>76</sup> IEA. [Global Gas Security Review 2023](#). July 2023. Page 56.

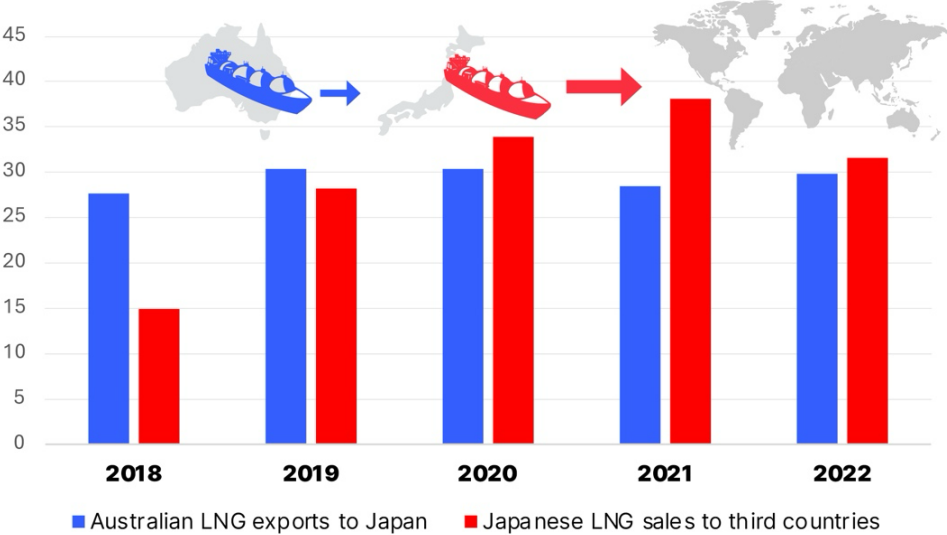
<sup>77</sup> Handling includes not only domestic use of LNG covered by long- and short-term contracts and spot purchases, but volumes sent to other countries via offtake rights or tolling agreements or short-term or spot procurement.

companies to third countries from FY2020-22 averaged about 30MTPA and was higher than the volume of Australian LNG imported by Japanese companies (Figure 11).

While Japan has stated that it relies on Australian LNG, Japan’s resales to third countries suggests that if Australia stopped exporting LNG to Japan tomorrow, it could potentially divert enough volume from its third-party resales to replace Australian volumes.<sup>78</sup>

Despite the prospect of domestic demand falling to 50MTPA this decade, the Japanese Ministry of Economy, Trade and Industry is targeting a 2030 handling target of 100MTPA and is instructing Japanese firms to cultivate demand across Southeast Asia.<sup>79</sup> The current surplus will continue to grow this decade, adding to the competitive pressure facing Australian LNG exporters.

**Figure 11: LNG sales by Japanese companies to third countries compared with Australian LNG exports to Japan**



Sources: JOGMEC<sup>80</sup>; Kpler.

### LNG market prices likely to fall in coming years

The looming glut in LNG supply and relatively low global variable LNG supply costs will likely place significant downward pressure on LNG prices in coming years. This will be evident in spot market prices but may also impact on prices negotiated for new LNG SPAs. As shown in Figure 7, average LNG variable costs for key suppliers are below USD4/MMBtu, much lower than average LNG fixed (i.e. capital) costs.

<sup>78</sup> S&P Global Commodity Insights. [Japan concerned Australian gas security policy change could threaten LNG trade: official](#). February 2023.

<sup>79</sup> IEEFA. [Japan’s largest LNG buyers have a surplus problem](#). 11 March 2024. Page 9.

<sup>80</sup> JOGMEC. [Results of FY2023 Survey on LNG Handling Volume by Japanese Companies](#). 10 November 2023.

Recent Qatar pricing for new LNG SPAs has been in the range of 12% of Brent (equivalent to about USD10/MMBtu).<sup>81</sup> However, lower-than-anticipated demand will likely require Qatar to lower its pricing to sell its uncontracted supply (which is set to increase in coming years). This pressure on pricing is already being seen, with buyers seeking lower prices for new LNG SPAs and some buyers seeking to renegotiate already-signed binding term sheets before finalising and signing new LNG SPAs.<sup>82</sup>

This represents a key price risk for LNG exporters who are exposed to LNG spot market prices or who have LNG SPAs with variable pricing (i.e. linked to oil or LNG price benchmarks). The majority of Australia's LNG SPAs have pricing that is linked directly to either Brent or Japan Crude Cocktail (JCC) prices, exposing LNG exporters to the risks of price movements in these indices.<sup>83,84</sup> LNG exporters may be able to hedge this exposure but will typically incur additional costs to do so. LNG producers may choose to not hedge all of their price exposure – for example, Woodside has hedged only part of its exposure to price movements at the Title Transfer Facility and Henry Hub for its Corpus Christi LNG volumes.<sup>85,86</sup>

LNG SPAs with pricing linked to less liquid benchmarks will have similar risks, but may be challenging to hedge, particularly over longer time horizons. The Japan Korea Marker (JKM), for example, has exhibited significant volatility over the past decade, with JKM seeing both record lows and highs.<sup>87</sup> However, JKM futures have limited liquidity beyond a one-to-two-year window, limiting the ability of parties to hedge against future price movements for longer terms.

While lower prices may benefit buyers and spur some responsive demand as buyers seek to take advantage of lower prices, they will reduce project revenue and potentially undermine investment returns. This reflects two factors: LNG variable costs are sufficiently low to drive down global LNG prices; fixed costs are generally large and likely to require a higher LNG price. In Australia, fixed costs have historically been more than three times higher than variable costs (as shown in Figure 7) – while an 'average' Australian LNG exporter could cover its variable costs at prices below USD4/MMBtu, it would require prices higher than USD10/MMBtu to cover lifetime project costs.

Exposure to volatile prices is likely to impact on most Australian LNG exporters. However, Santos is particularly exposed to JKM price volatility given its JKM-linked LNG SPA with Mitsubishi, intended to be supplied with gas extracted from the new Barossa gas field.

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<sup>81</sup> Brent is a crude oil price that is often used to price LNG under long-term LNG SPAs. Pricing is often expressed as a percentage of the Brent price.

<sup>82</sup> S&P Global Commodity Insights. [Asian LNG buyers seek to lower long-term contract slopes as markets shift](#). May 2024.

<sup>83</sup> The Japan Crude Cocktail represents the average price of crude oil imported into Japan and is often used to price long-term LNG SPAs.

<sup>84</sup> IEEFA analysis of ICIS LNGEdge data.

<sup>85</sup> The Title Transfer Facility is a virtual gas trading hub in Holland, which is sometimes used to price gas and LNG under contracts.

<sup>86</sup> Woodside. [First Quarter Report for Period Ended 31 March 2024](#). 19 April 2024. Page 5.

<sup>87</sup> The Japan Korea Marker is a price assessment for LNG spot cargoes delivered into the North Asian region which is sometimes also used to price LNG under contracts.

## Darwin LNG price risks could undermine Barossa project returns

In 2020, Santos and Mitsubishi signed a new 10-year LNG SPA for 1.5Mpta, with pricing “based on the Platts Japan Korea Marker”.<sup>88</sup> That is, prices for LNG delivered under the contract will be directly linked to JKM, which represents a key financial risk given the lack of ability to hedge JKM over the full term of the LNG SPA and rising development costs for the Barossa project.

Santos is currently developing the offshore Barossa gas field to backfill Darwin LNG, which is presently offline due to the Bayu Undan gas field being depleted, with an original estimated development cost of USD3.6 billion. This equated to an estimated cost of about USD5.50/MMBtu.<sup>89</sup>

However, development of the Barossa field was delayed following legal challenges to its approvals, which has impacted on timing and increased estimated project costs by USD300 million. This is likely to increase the per-MMBtu cost of producing LNG to satisfy Santos’ supply obligations under its SPA with Mitsubishi.

At the same time, reforms to Australia’s Safeguard Mechanism will require Santos to fully offset any reservoir CO<sub>2</sub> emissions from the Barossa field, which has a reservoir CO<sub>2</sub> content of about 18%. IEEFA estimates that fully offsetting these emissions with ACCUs would cost more than AUD400 million, though Santos has proposed the development of the Bayu Undan CCS project to offset these emissions.

As noted earlier, the costs of developing the Bayu Undan CCS project are expected to exceed USD1.6-1.7 billion, which will further add to the per-MMBtu cost of LNG produced by Santos, and could see costs rise to above USD6/MMBtu.

The Bayu Undan CCS project also face operational risks, and globally CCS has attained a reputation as an expensive and unreliable technology.

Recent periods of LNG oversupply (in 2016 and 2019) led to the JKM falling to below USD5/MMBtu (albeit for relatively short periods).<sup>90</sup> However, a sustained period of oversupply, which IEEFA expects will occur in the second half of this decade, could see Asian LNG spot prices remain at low levels for longer periods, representing a clear financial risk for Santos as it faces increasing costs and exposure to a price marker that cannot fully be hedged.

## Domestic supply and social licence concerns create risks for Australia’s LNG exporters

While Australia’s LNG growth wave was remarkable given Australia’s relatively limited reserves, it has coincided with increasingly tight domestic supply conditions, which risk the industry’s social licence, and declining gas exploration and development expenditure.

<sup>88</sup> Santos. [Santos and Mitsubishi sign SPA for Barossa LNG Supply](#). 7 December 2020.

<sup>89</sup> S&P Global Commodity Insights. [Australia’s Santos takes FID on Darwin LNG Barossa backfill project](#). 30 March 2021.

<sup>90</sup> S&P Global Commodity Insights. [JKM hits record low amid Chinese demand uncertainty, weaker Eurogas](#). 3 February 2020.

## Tight domestic supply could see exports diverted

Australian domestic gas markets are facing increasingly tight supply conditions due to declining domestic supply and strong LNG exports. This has led to gas prices increasing above historical levels, contributing to high energy bills and challenging market conditions for industrial gas users. Governments across Australia have responded in a number of ways.

Prompted in particular by concerns about the prospect of a supply gap on the east coast, the Australian Government implemented the Australian Domestic Gas Security Mechanism, which provides the Minister for Resources with the power to redirect LNG exports (including LNG intended to satisfy long-term LNG contracts) to the domestic market if there is likely to be a supply gap. This mechanism was recently strengthened to make it easier for the Minister to trigger export controls.<sup>91</sup>

The Australian Government responded to high gas prices on the east coast in 2022 by implementing a price cap of AUD12 per gigajoule for the ‘first sale’ of gas, and by legislating a mandatory code of conduct intended to incentivise gas producers and LNG exporters to supply more gas into the domestic market.<sup>92</sup>

In 2022, the Australian Energy Market Operator (AEMO) activated the Gas Supply Guarantee, an agreement between the Australian Government and the Queensland LNG exporters, which resulted in additional supply to the domestic market to ensure sufficient gas supply for electricity generation.<sup>93</sup>

In the Northern Territory (NT), declining gas supply from a legacy offshore gas field led to the NT Government entering into an emergency arrangement with LNG exporters Santos and Inpex to secure additional supplies for electricity generation.

In 2023, the Western Australian Parliament Economics and Industry Standing Committee commenced a review of the state’s Domestic Gas Policy (which sets out the existing reservation policy). The Committee’s Interim report found that the existing policy is no longer fit-for-purpose and “appears in some cases to be ineffective in ensuring the delivery of domestic gas in a timely manner”.<sup>94</sup> The report also found there is a case for further government intervention and outlined a number of possible options to ensure sufficient domestic supply, noting that “key features of the WA Domestic Gas Policy (the Policy) are designed to ensure the State’s domestic gas requirements do not go unmet, even in circumstances where it may be more profitable for producers to export LNG than market gas to West Australian consumers.”<sup>95</sup>

While the Committee has not yet released its final report, it seems possible that WA’s domestic gas reservation policy will be strengthened to require LNG exporters to supply greater volumes to the domestic market (likely at the expense of LNG exports).

<sup>91</sup> S&P Global Commodity Insights. [Reforms reshape the Australian gas market](#). 27 April 2023.

<sup>92</sup> Australian Competition and Consumer Commission. [Gas inquiry June 2023 interim report](#). June 2023. Page 8.

<sup>93</sup> Department of Climate Change, Energy, Environment and Water. [AEMO takes steps to manage tight gas supply](#). 20 July 2022.

<sup>94</sup> WA Parliament Economics and Industry Standing Committee. [Domestic Gas Security in a Changing World: Inquiry into the WA Domestic Gas Policy: Interim Report](#). 22 February 2024. Pages xi and 23.

<sup>95</sup> Ibid. Page ix.

Challenging domestic market conditions in Australia have also impacted on the social licence of the industry. The Minister for Resources, Madeleine King, warned in 2022 that the gas industry is losing its social licence due to gas producers (specifically on the east coast) prioritising exports over domestic supply.<sup>96</sup> It seems likely that LNG exporters will face increasing social pressure to divert exports to the domestic market, particularly in light of the looming LNG supply glut.



**It seems likely that LNG exporters will face increasing social pressure to divert exports to the domestic market, particularly in light of the looming LNG supply glut.**

Market participants expect this glut to push down LNG prices, which is likely to make it more financially attractive for LNG exporters to prioritise domestic supply rather than exports (given current high domestic gas prices).

The potential for diversion of exports (in the context of the east coast) was recognised by the Graeme Bethune from the Oxford Institute for Energy Studies, who noted: “In these circumstances it seems inevitable that Queensland LNG producers will be required to divert increasing volumes of gas to southern markets, particularly in winter, reducing LNG exports. This would occur under the ADGSM. This is described as a measure of last resort, only used if market-based solutions and other regulatory interventions fail to provide sufficient gas to Australian consumers. It has not been triggered for 2023. The policy guidelines recognise the need to protect long-term foundation contracts and to consider the impact on Australia’s reputation as a reliable trade and investment partner. However, the interests of Australian consumers (voters) take precedence.”<sup>97</sup>

## Declining exploration and development will reduce LNG exports

Australia’s gas reserves, which are low compared with other major gas producers, are in decline and are not being replaced with new reserves.<sup>98,99</sup> This reflects several factors, including increasing LNG competition, fierce competition for capital amid a global decline in upstream exploration expenditure, and perceptions that Australia is a high-cost gas producer. As noted by Wood Mackenzie, “High costs and cheaper competition threaten Australia’s ability to compete for the next wave of oil and gas investment, particularly in the key LNG market segment.”<sup>100</sup>

In IEEFA’s opinion, a glut of new low-cost LNG supply and uncertain future demand are likely to make it increasingly difficult for Australian gas producers and LNG exporters to attract investment. This may explain, at least in part, why Australia’s oil and gas exploration expenditure has fallen in recent decades (Figure 12), with recent expenditure well below historical levels, particularly for

<sup>96</sup> AFR. [King readies gas trigger, as exporters lose ‘social licence’](#). 1 August 2022.

<sup>97</sup> Oxford Institute for Energy Studies. [Is Australia quietly quitting the LNG business?](#) June 2023. Page 16.

<sup>98</sup> BP. [Statistical Review of World Energy 2021](#). July 2021. Page 2.

<sup>99</sup> Oxford Institute for Energy Studies. [Is Australia quietly quitting the LNG business?](#) June 2023. Page 1.

<sup>100</sup> Wood Mackenzie. [Australia Oil & Gas Industry Outlook Report](#). March 2020. Page 16.

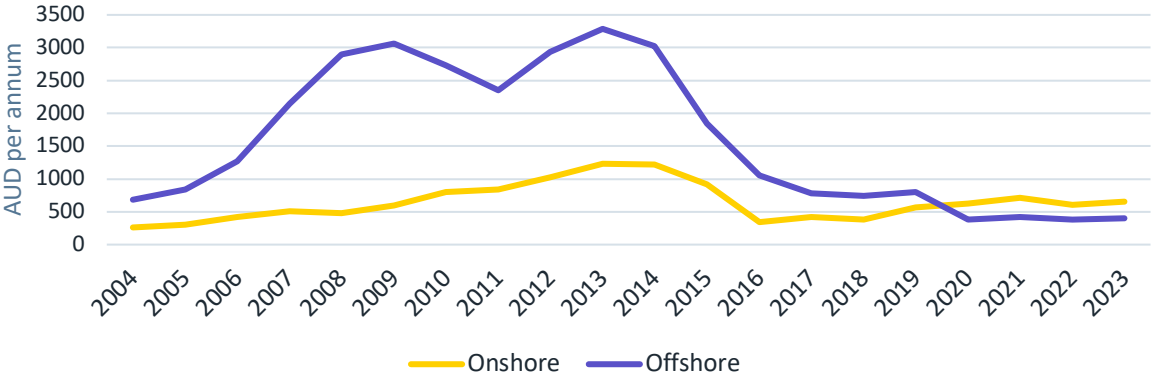


offshore oil and gas. By the early 2020s, expenditure had fallen to levels similar to those two decades ago.

In Queensland, a major exporting region, petroleum exploration fell by 68% between 2014 and 2023, from a peak of AUD726 million to AUD232 million.<sup>101</sup> This downtrend trend is also seen at the national level, with total petroleum exploration down by 77% from a peak of AUD4.74 billion in 2014, to AUD1.06 billion last year.

The decline in spending on oil and gas projects comes at a time when projects are facing increased costs (as noted earlier), and is in contrast with industry assertions that further gas development is needed in Australia. It raises questions about the ability and willingness of gas and LNG exporters to increase investment to maintain current production levels.

**Figure 12: Australia’s oil and gas exploration expenditure by calendar year (trend)**



Source: Australian Bureau of Statistics.<sup>102</sup>

IEEFA notes that this may be a reflection of unfavourable economic returns for development of more marginal gas fields in Australia (particularly compared with other investment opportunities). New gas fields are likely to be more costly to develop, and the fall in exploration expenditure has coincided with increasing investment in the mining of base metals and metal ores.<sup>103</sup>

In IEEFA’s view, there is unlikely to be a financial case for further exploration in new gas fields, which is likely why, according to the Oxford Institute for Energy Studies, “... Australian energy companies, like their global peers, are slashing their exploration budgets, sacking their explorers and shifting their investment to renewables or handing money back to the shareholders.”<sup>104</sup> A recent IEEFA commentary noted that reducing investment expenditure and divesting assets are key strategies for companies in declining industries.<sup>105</sup>

<sup>101</sup> Australian Bureau of Statistics (ABS). [Mineral and Petroleum Exploration, Australia, December 2023](#). 4 March 2024.  
<sup>102</sup> ABS. [Mineral and Petroleum Exploration, Australia, December 2023](#). 4 March 2024.  
<sup>103</sup> Ibid.  
<sup>104</sup> Oxford Institute for Energy Studies. [Is Australia quietly quitting the LNG business?](#) June 2023. Page 11.  
<sup>105</sup> IEEFA. [Australian gas companies need a new strategy as they enter a declining market](#). 9 April 2024.

Declining investment in the face of increased competition in both LNG and capital markets is likely to result in Australian gas production declining in coming years, with flow-on impacts for LNG exports. While Australia was the world's largest exporter, its LNG exports are likely to materially decline in coming decades (with or without government support).

## An accelerated decline in gas production will bring forward decommissioning obligations

Declining LNG exports, including due to diversion of gas to the domestic market, create financial risks for LNG exporters. Specifically, lower exports could lead to underutilisation of gas and LNG infrastructure, potentially undermining financial returns. It could also see LNG assets become stranded or mothballed before the end of their useful life. For example, Woodside announced in 2023 it intends to take train 2 at its North West Shelf facility offline due to insufficient supply.<sup>106</sup>

It could also bring forward decommissioning obligations, meaning LNG exporters will be subject to decommissioning costs sooner. Decommissioning presents a significant financial challenge for the industry; in the event of a rapid phase-out of gas, it could also see the burden fall to Australian taxpayers.<sup>107</sup> Recent estimates suggest Australia's oil and gas industry faces decommissioning costs of more than USD40 billion, which will only increase as new gas fields are developed and additional infrastructure is installed.

Gas and LNG companies may seek to defer decommissioning obligations by proposing development of CCS facilities utilising existing infrastructure.<sup>108</sup> As noted by IEEFA, "Santos withdrew decommissioning plans for the Bayu-Undan field following a proposal to use it for CCS (despite not releasing any cost estimates or technical studies that demonstrate its feasibility)."<sup>109</sup>

Under Australian law, CCS operators can face liability for any leakage of CO<sub>2</sub> injected into CCS sites, creating ongoing risks for CCS proponents.<sup>110</sup> CCS facilities in Commonwealth waters may have this liability limited to a 15-year period under existing law (provided the Minister for Resources is satisfied that ongoing leakage risks are low), but no such provision applies for CCS facilities in Victoria, South Australia and Queensland.<sup>111</sup>

As noted by King, Wood and Mallesons, "... the risk of leakage is an important one to consider and quantify for potential investors. The availability of insurance to cover these risks will be a key issue for CCS project developers."<sup>112</sup>

<sup>106</sup> Woodside Energy. [Full-Year 2023 results briefing transcript](#). 27 February 2024.

<sup>107</sup> IEEFA. [Australia's decommissioning challenge raises financial risks for governments and shareholders](#). 18 December 2023.

<sup>108</sup> Ibid.

<sup>109</sup> Ibid.

<sup>110</sup> King, Wood and Mallesons. [CCS in Australia - A Legal Guide](#). 30 March 2022.

<sup>111</sup> Ibid.

<sup>112</sup> Ibid.

## Conclusion: Australian LNG returns face a range of financial risks

Australia's LNG exporters face a range of risks that could impact on financial returns for both existing and future investments.

The key risk examined in this report is that future anticipated LNG demand in emerging markets does not materialise and demand in mature markets continues to decline. Lower-than-anticipated demand, in the context of a wave of new LNG, will create challenging market conditions for Australian LNG exporters, impeding their ability to execute new LNG SPAs at prices that provide a sufficient return.

Australian LNG exporters may also become increasingly exposed to LNG spot market prices (with JKM the benchmark for LNG spot sales in Asia) if they are unable to enter into new LNG SPAs to replace expiring contracts.

Periods of low LNG spot prices could lead to LNG exporters prioritising supply to the domestic market, particularly if domestic market provides a price premium to LNG spot exports. In addition to reducing total export volumes, this would also lower utilisation rates for Australia's LNG liquefaction assets.

More generally, lower-than-anticipated LNG demand and declining domestic reserves could lead to some LNG liquefaction infrastructure becoming stranded or being mothballed, undermining returns on the large capital investments required to build this infrastructure (with the majority of Australian LNG projects already underperforming financially).

Financial risks to LNG exporters could also present fiscal risks for Australian governments. While LNG is currently a major export, the inevitable decline in export earnings is likely to see royalties and taxes payable by the industry falling in coming years. From a fiscal viewpoint, continued production at existing fields is likely to have less impact on government revenues given gas and LNG exporters are likely to have recovered at least a portion of their upfront costs, meaning mature fields are likely to have fewer or no remaining tax deductions. In contrast, the costs of developing new fields could lead to lower taxation revenue due to new deductions associated with project development costs.

Development of CCS projects also present risks for taxpayers given the shift of liability from project operators to government, and the possibility of unanticipated leakages.

Finally, taxpayers face risks arising from the decommissioning obligations of the oil and gas industry. Specifically, a rapid phase-out of oil and gas could affect the ability of companies to meet their obligations, which could fall to government as 'decommissioner of last resort'. The magnitude of Australia's decommissioning liability, estimated at more than USD40 billion, amplifies this risk.

## About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. [www.ieefa.org](http://www.ieefa.org)

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