May 2025

Australia’s Natural Gas Investment Competitiveness

Prepared for Australian Energy Producers

Executive summary

Investment in natural gas exploration and domestic supply, Liquefied Natural Gas (LNG) and Carbon Capture and Storage (CCS) projects is highly cyclical – strongly correlated with energy demand and commodity prices. Australia has been a long-term beneficiary of this investment (particularly in LNG) but the trend over the last decade has been a material decline in Australia's share of investment capital when compared to Peer Countries (the United States (U.S), Canada, Qatar, Norway, China, South-East Asia and Africa).

This is despite an ongoing role for gas in Australia's domestic markets, and LNG demand continuing to grow. The Australian Energy Market Operator (AEMO) notes that gas will continue to be used by Australian households, businesses, and industry, and will support the operation of the electricity sector during Australia's energy transition. Wood Mackenzie forecasts global LNG demand to rise 58% by 2050 (from 435 mmtpa in 2025 to nearly 690 mmtpa by 2050). The Asia Pacific region currently accounts for approximately 63% of global LNG demand and the region's LNG demand is expected to grow at a 2.5% Compound Annual Growth Rate (CAGR) from 2025 to 2050, eventually comprising nearly 75% of global LNG demand by 2050. Improved LNG affordability, structural declines in domestic gas production in Asian gas producing nations, and decarbonisation policies will drive this long-term growth.

Australia's share of natural gas, LNG and CCS investment has seen significant growth since 1990, delivering reliable and affordable domestic gas supply and transforming the country into a major player in the global energy market. The period from 2009 to 2017 saw an unprecedented boom in gas production and LNG investment, with Australia capturing up to 25% of Peer Countries' natural gas and LNG capital expenditure during peak years. This surge was driven by the construction of multiple world-scale LNG projects, including Gorgon, Wheatstone, Ichthys, Prelude and the three Coal Seam Gas to LNG (CSG-to-LNG) projects in Queensland.

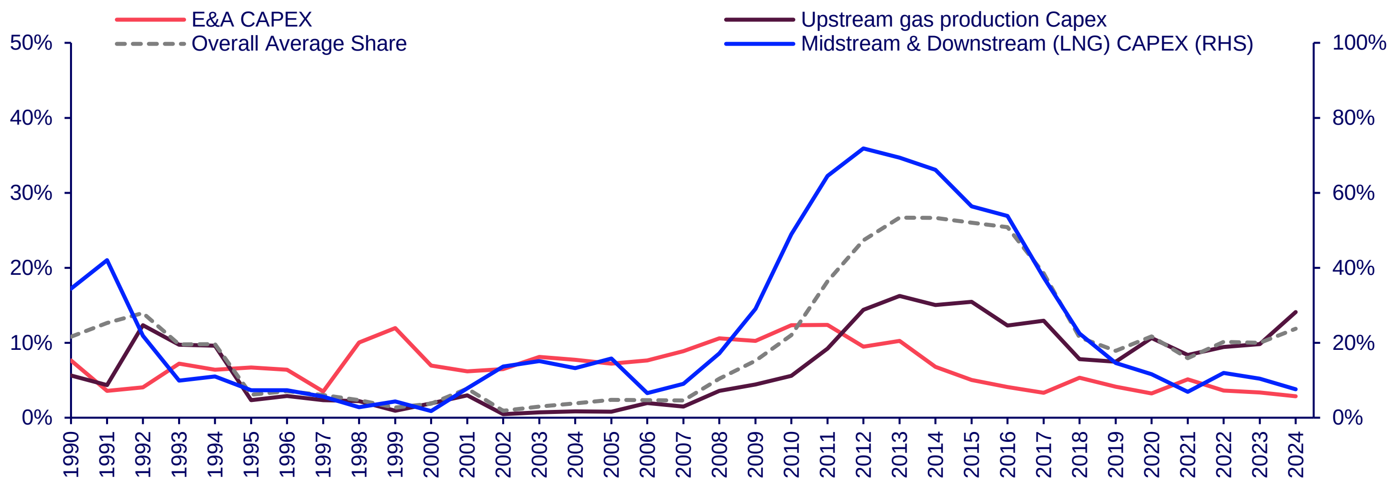
However, in mid-2014 a global oversupply of oil caused energy prices to fall sharply, returning to levels last seen in the early 2000s. The sector continued to suffer low prices during the late 2010s and through the COVID-19 pandemic in 2020. Oil prices significantly impact LNG prices due to their historical linkage in long-term contracts and their role as competing fuels in various energy markets. As a result, over this period global investment in the natural gas and LNG sectors fell massively, and the industry has had to reset and drive efficiency and carefully manage capital. This has been relatively successful – global production has continued to increase despite falling investment, lower Exploration and Appraisal (E&A) activity has still managed to find similar quantities of new resource, and the marginal cost of production has continued to reduce.

As oil prices fell from (average annual, Real 2025) US$134/bbl in 2014 to just over US$51/bbl (average annual, Real 2025) in 2020, Peer Country natural gas and LNG investment fell from US$138bn to under US$60bn. E&A investment across Peer Countries fell from $76bn to less than US$15bn over the same period. Whilst oil prices have recovered somewhat from their 2020 lows to average above US$80/bbl across 2021 to 2024 (Real, 2025), post-COVID-19 gas and LNG investment across Peer Countries has stayed well below the 2014 peak (and Australia has had minimal share of this investment).

Australia has been losing its share of Peer Country investment in natural gas and LNG

While overall investment has not recovered to the highs of the mid-2010s, the sector has shown signs of recovery post the COVID-19 pandemic. As oil prices have recovered in recent years, there has been a modest uptick in E&A activity. A post-COVID-19 pandemic recovery in LNG liquefaction investment has been marked by a resurgence of project sanctioning and capital commitments, driven by a confluence of factors. However, the recovery in activity has not been evenly spread across regions. Since 2020, Australia has significantly lagged the Capital Expenditure (CAPEX) investment growth in Peer Countries across both E&A activity (29.5% global growth, 15% in Australia) and investment in downstream LNG liquefaction capacity (88.1% globally, 22.8% in Australia). Australia has struggled to maintain its long-term average share of Peer Countries' E&A spend, stabilising at approximately 3%.

Australia's share of total Peer Countries' natural gas and LNG CAPEX, 1990-2024[1]



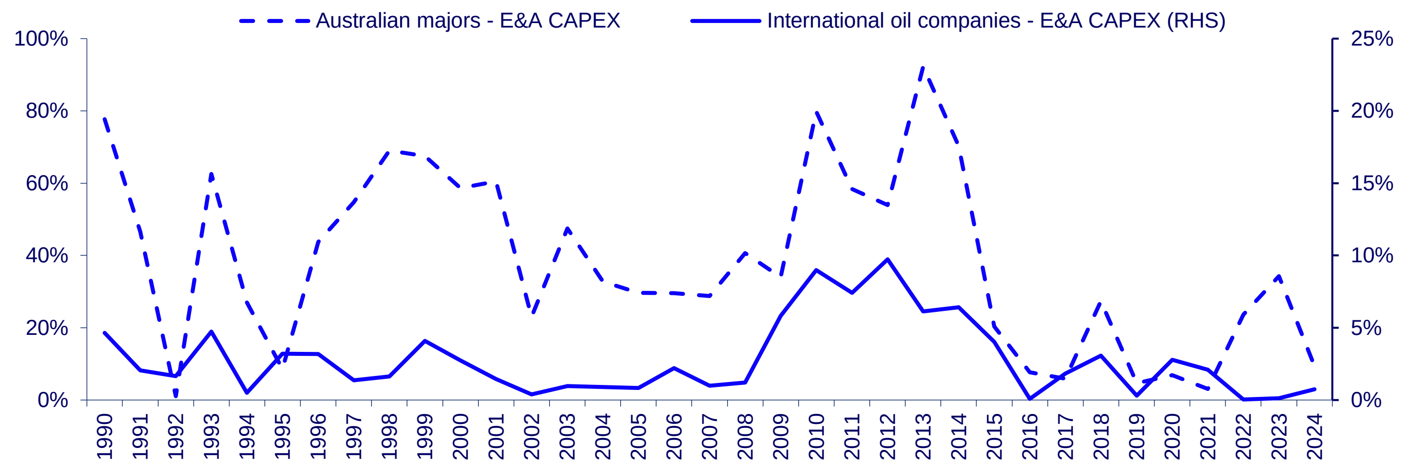
1. Includes CAPEX for E&A (gas wells), upstream gas production, midstream and downstream gas processing (LNG) and CCS projects. Excludes US L48 and Canada.

Australia is also losing portfolio share of the major International Oil Companies (IOCs)

Major IOC investment in Australia surged from the early 2010s, peaking at nearly 40% of their combined overall portfolios resulting from significant investment in various Australian LNG facilities and upstream gas production projects. Since then, with the pace of new project development slowing down, Australia's share of IOC portfolios has fallen to an average of approximately 15% over the past 5 years. Upstream gas production spend remains robust as a share of total portfolio; however, this reflects both the need to continuously backfill Australian LNG plants and meet domestic supply commitments with new upstream production, and a decreasing overall upstream gas production spend in Peer Countries. In contrast, the two Australian majors have increased their investment in Australia over the last five years. Woodside's additional investments in the Scarborough/Pluto expansion projects and Santos's investments in the Barossa-Caldita fields have driven this growth.

Looking forward, however, the trend is much starker – both the IOCs and Australian majors have significantly reduced their investment in Australian E&A. Even though overall E&A activity has fallen across all Peer Countries, Australia has still received a lower proportional share of that activity than the long-term average, over the last five years. The major IOCs have committed just 1.2% of their global E&A investment to Australia over the last five years. The Australian majors, who have a natural competitive advantage in Australia, have invested an average of only 15% of their total E&A spend in the country over the same period. This compares to a long-term average of over 42% of total portfolio E&A spend between 1990 and 2019.

Australia's share of IOC and domestic major E&A CAPEX, 1990-2024[1]



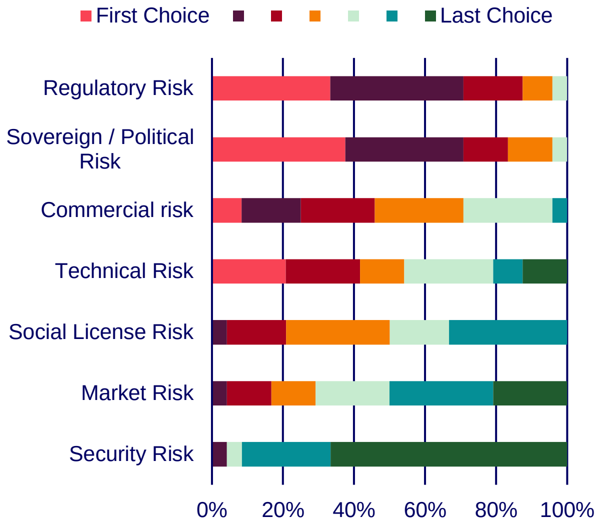
1. *Includes CAPEX for E&A (all wells). Excludes US L48 and Canada.*

It is clear that Australia is losing out in the competition for gas and LNG investment capital – but what is driving this?

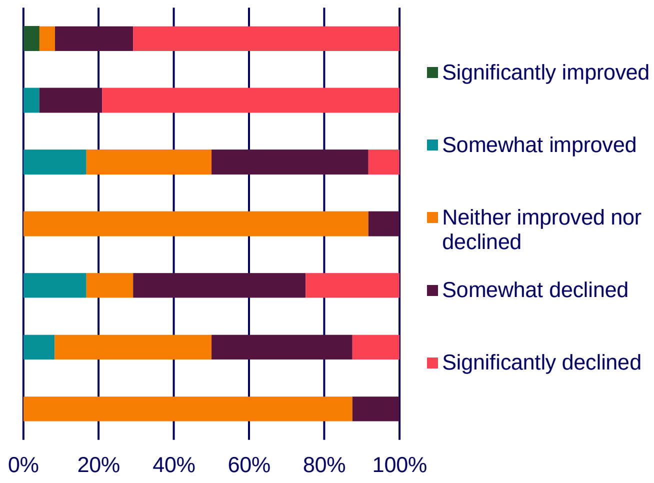
There are multiple complex factors that drive investment and capital allocation decisions. Wood Mackenzie have sought (through analysis and a survey of Australian Energy Producers' membership) to explore which factors have improved, and which have deteriorated, in Australia over recent years. A survey of Australian Energy Producers member CEOs – representing companies that combined account for over 85% of total gas production by volume in Australia – ranked Regulatory and Sovereign Risk as the most important factors considered when making investment decisions in Australia. Commercial and Technical Risk also ranked highly – countries need attractive, stable fiscal terms and strong prospectivity, but above all investors are seeking regulatory stability and supportive Government policy to underpin capital allocation decisions.

Unfortunately, investors also consider that the most important risks (Regulatory Risk, Sovereign / Political Risk) have deteriorated the most over the last five years. Over 91% of survey respondents believe Australia's Regulatory Risk has Significantly or Somewhat Declined (meaning risk has worsened) over the last five years, and almost 96% believe Australia's Sovereign / Political Risk has followed the same trajectory.

What are the most important factors considered when Making investment decisions in Australia?



How have these risks for Australia changed over the last five years?



Wood Mackenzie's analysis of Australia's investment attractiveness compared to Peer Countries demonstrates that Australia remains an attractive investment destination across a range of factors:

Commercial and fiscal risk Australia's fiscal terms and commercial returns remain competitive with Peer Countries – fiscal terms are stable, total government share is comparable and other metrics including front-loading and flexibility are competitive.

Market attractiveness Australia is significantly advantaged in its location – proximate to large centres of energy demand in Asia. Australian LNG is shipped to Asia at half the cost of the United States and Qatar, and less than a third of the cost of African producers.

Technical risk and prospectivity Australian exploration performance is highly competitive – high well success rates (>35%) and large average discovery volumes (>200mmboe) are comparable to prolific basins in the United States and Africa. Australia's technical prospectivity remains among the highest amongst Peer Countries – large discovered volumes and remaining 2P reserves in areas served by existing infrastructure make Australian resources attractive to invest in.

Security risk Security in Australia is among the best in the world – prosperous, politically stable and comparatively safe.

With this in mind, why hasn't Australia managed to maintain its share of natural gas and LNG investment capital over the last decade?

Delays, cancellations and increasing costs – the political and regulatory burden is increasing

While Australia's resources, access to markets, market certainty, fiscal terms, ability to raise finance and obtain social license are seen as positives that support investment in Australia – energy and climate policies, environmental regulation, permitting and approvals processes and the lack of regulatory and political certainty are driving investment down. Competitiveness is being further eroded by emerging activist "lawfare", with court challenges being lodged to overturn previously granted regulatory approvals and delaying major projects in recent years. Indeed, 95% of respondents to the survey on Australia's competitiveness believe Australia's natural gas exploration, production and LNG sectors have become somewhat or significantly less attractive over the last 5 years.

Additionally, 95% of respondents to the Australian Energy Producers survey have had investments directly impacted by a change in Government policy or regulation. Of these, a fifth did not proceed or were relocated outside of Australia, and almost half were significantly delayed. Since the mid-2010s, some large upstream projects in Australia have taken between 6 and 9 years to gain relevant approvals and progress from proposal to first gas.

Regulatory and political risk has increased over the last decade – the East Coast Gas Market Code, Safeguard Mechanism, Australian Domestic Gas Security Mechanism (ADGSM), Heads of Agreement, Petroleum Resource Rent Tax (PRRT) reforms, Environment Protection and Biodiversity Conservation (EPBC) Act reform and net zero obligations were all introduced (and for many, subsequently modified) in the last 10 years. On top of this the cost to develop resources has also increased – delays to projects increase costs, and inflation and supply chain constraints have led Unit Development Costs to grow over the last five years – with Australia having among the highest increases amongst Peer Countries.

CCS is still in a very early stage of development, and investment is volatile

The role of CCS in emissions reduction strategies is likely to grow as hard-to-abate sectors face more stringent emissions controls and regulation. CCS plays a crucial role by capturing the CO_2 emissions, which are then compressed and transported for usage or injection into deep geological formations such as oil and gas reservoirs or saline aquifers. Governments and industries are increasingly recognising the potential of this technology to help achieve ambitious climate targets.

Australia has unique and significant potential to become a key player in CO_2 importation and CCS partnerships, particularly for Asian countries aiming to decarbonise their energy sectors. The country's vast and geologically suitable areas for CO_2 storage, including depleted oil and gas fields and deep saline aquifers, position it as an attractive destination for CO_2 sequestration.

Geographically, while North America continues to lead in terms of operational projects, there is growing interest and investment in Europe, Asia, and Australia. Projections suggest that cumulative global investment in CCS could reach US$1 trillion by 2050 to align with net-zero emissions scenarios, however the sector is nascent, and it is as yet unclear how it will develop over time. Recent investment (2021 onwards) has been focused on CCS hubs and a repositioning of oil and gas companies to leverage their specialist skills and competitive advantages to pursue CCS as a business that compliments oil and gas production.

It is expected that global CCS investment will grow, and Australia will need to demonstrate strong competitiveness to fight for investment capital in the sector. As CCS is mostly considered an additional cost to industry, achieving competitive costs for CO_2 capture, transport and storage will be critical to successfully growing local capacity. This will require strong Government support for the sector, stable and sensible regulation, a streamlining of project approval processes to ensure projects can be delivered quickly, efficiently and at a competitive cost, and bilateral agreements to be put in place as a matter of urgency to allow for the import and export of CO_2 for storage.

Where to from here?

With the Federal Government's Future Gas Strategy making clear the critical, long-term role for gas to support the decarbonisation of power generation and the continuation of local industry in this country, the need to encourage investment in the development of Australia's gas resources is obvious and pressing. Streamlining the process for exploration, appraisal and development approvals is critical to lowering investment risk. Recognising the vital role of gas in the energy transition and supporting it with appropriate policies is key to providing industry with the confidence it needs to invest. Approvals timeframes should not be indefinite, and when approvals are given, there needs to be more certainty that they can be relied upon.

This year's review of the Gas Market Code, the East Coast LNG exporters Heads of Agreement and the ADGSM are an opportunity for the government to reshape its relationship with the industry, provide the incentives and certainty needed to boost investment sentiment and support one of Australia's most significant domestic and export industries.

Australia remains an attractive destination for natural gas, LNG and CCS investment – but without improvements in policy and regulation, and an increase in the stability and efficiency of processes, Australia risks become uncompetitive in the fight for investment capital – not just across the natural gas and LNG sectors, but in new energy sectors such as CCS that have high potential growth trajectories.

Contents

Glossary

Term	Description
ACCC	Australian Competition and Consumer Commission
ADGSM	Australian Domestic Gas Security Mechanism
AEMO	Australian Energy Market Operator
ALARP	As Low As Reasonably Practicable
boe	Barrels of Oil Equivalent
CAD	Canadian Dollars
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CCS	Carbon Capture, and Storage
CCTP	Carbon Capture Technologies Program
CSG	Coal Seam Gas
E&A	Exploration and Appraisal
ECGM	East Coast Gas Market
EDO	Environmental Defenders Office
EIA	Environmental Impact Assessment
EPBC	Environment Protection and Biodiversity Conservation
ESG	Environmental, Social and Governance
FID	Final Investment Decision
FPSO	Floating Production, Storage and Offloading
G&A	General and Administrative Costs
GJ	Giga Joules
GPG	Gas Power Generation
GoM (GoA)	Gulf of Mexico (Gulf of America)
GPI	Global Peace Index
ILUAs	Indigenous Land Use Agreements
IOC	International Oil Companies
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
mmboe	Million Barrels of Oil Equivalent
mmBtu	Million British Thermal Units
mmtpa	Million Tonnes per Annum
NGER	National Greenhouse Energy Reporting
NOCs	National Oil Companies
NOPSEMA	National Offshore Petroleum Safety and Environmental Management Authority
OECD	Organisation for Economic Co-operation and Development

Term	Description
OPP	Offshore Project Proposal
PRMS	Petroleum Resource Management System
PRRT	Petroleum Resource Rent Tax
PSCs	Production Sharing Contracts
SEC	Securities Exchange Commission
SSGI	Ship propulsion technology: Slow-Speed Gas Injection
tcf	Trillion Cubic Feet
TLP	Tension Leg Platform
US	United States
US L48	United States Lower 48
UDC	Unit Development Cost
US$/bbl	U.S Dollars per Barrel of Oil
US$bn	Billion U.S Dollars
YTF	Yet to Find

1. Introduction

In a competitive global market, Australia's ability to attract future investment in our oil and gas industry is not assured. Regulatory and policy stability, efficient environmental approval timelines, fiscal settings and labour costs are all factors that companies weigh in their decisions to allocate capital to Australia or elsewhere.

Australian Energy Producers engaged Wood Mackenzie to examine global investment trends for natural gas exploration and production, LNG developments, and carbon capture, CCS projects to assess the health of Australia standing in global gas markets investment environment.

The objective of this study is to:

- Analyse investment trends in natural gas exploration, production, LNG and CCS capacity globally and in Australia.
- Analyse and compare the key metrics impacting natural gas exploration, production, LNG and CCS investment in Australia.
- Identify the key factors influencing decision makers when considering natural gas exploration, production, LNG and CCS investment in Australia.

Scope of analysis

This report examines global investment trends for natural gas exploration and production, LNG capacity, and CCS and considers Australia's share of that investment. The analysis incorporates a quantitative analysis and discussion of the changing investment trends in natural gas exploration, production, LNG export and CCS capacity globally and in Australia. Specifically, the report includes analysis and commentary of:

- Annual investment in natural gas exploration, production, LNG export and CCS capacity since 1990 and planned in Australia, compared with global investment and particularly in the United States, Canada, Qatar, Norway, China, South-east Asia, and Africa.
- Annual investment in natural gas exploration, production, LNG export and CCS capacity since 2010 and planned in Australia, as a share of the aggregated investment portfolio of the oil and gas majors who have operated in Australia over this time, along with Woodside and Santos.

The report also includes a comparison of key metrics impacting investment in Australia against Peer Countries with respect to:

- Natural gas resources and reserves.
- Proximity to key markets, including shipping timeframes and costs.
- Cost of development and how this has changed over time.
- Wages costs, including average wage of natural gas sector workers.
- Fiscal terms, including taxes, royalties and fees on natural gas exploration, production, LNG and CCS investment.
- Greenhouse gas emissions constraints on new natural gas and LNG projects.
- Commentary on macro-trends related to environmental activism and 'lawfare'.

The Peer Countries considered in this analysis are:

- Australia
- The United States
- Canada
- Norway
- China
- Malaysia
- Indonesia
- Thailand
- Qatar
- Nigeria
- Libya
- Egypt

2. Investment trends in natural gas and LNG

Investment in oil, natural gas and LNG projects is highly cyclical – strongly correlated with energy demand and commodity prices. Volatile commodity prices, cyclical global economic growth – which itself drives energy demand – and advances in technology drive long-term cyclical trends in oil, gas and LNG exploration, production and processing. Australia has been a long-term beneficiary of this investment (particularly in LNG) but the trend over the last decade has been a material decline in Australia's share of global investment capital.

2.1. Historic investment

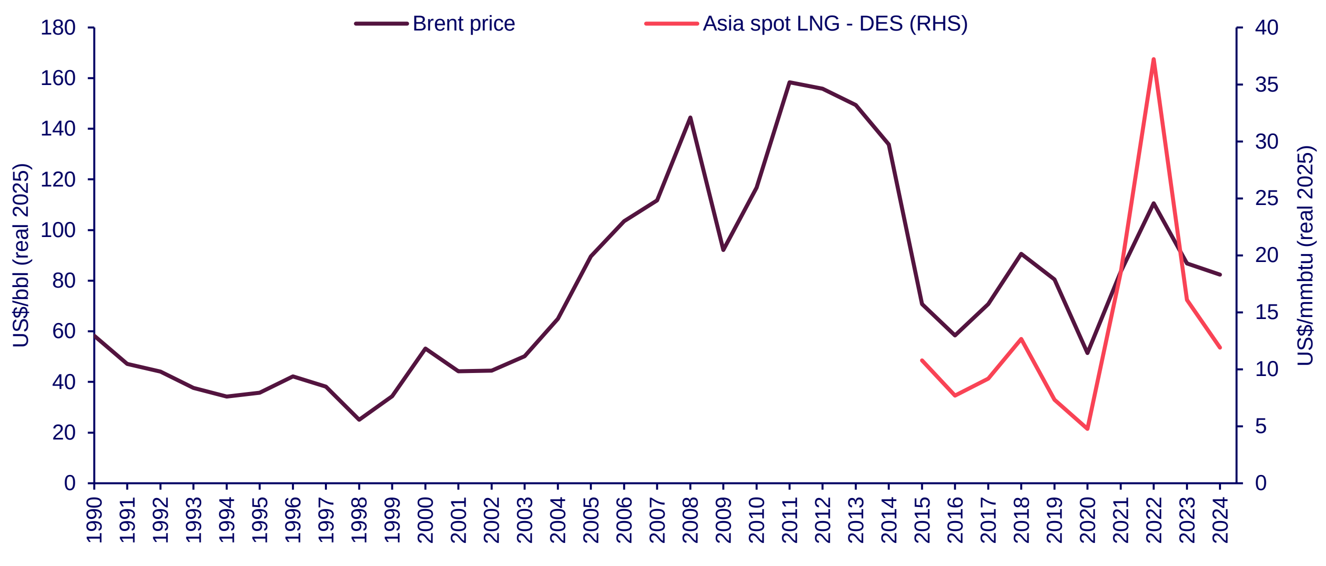
2.1.1. Commodity prices

Both Brent oil and Asia Spot LNG prices have shown significant volatility since 2000. The Brent oil price remained in the range of US$25 to US$60/bbl (average annual, Real 2025) until the early 2000s, before rising sharply in the mid-2000s as higher cost resources were needed to meet growing demand and global instability grew. Prior to the 2008-2009 financial crisis, Brent averaged US$144/bbl (Real 2025) in 2008, before falling steeply to US$90/bbl (Real 2025) in 2009. The global recovery raised Brent oil prices to record highs between 2010 and 2014, reaching US$158/bbl (annual average, Real 2025) in 2011.

In mid-2014, a global oversupply of oil caused energy prices to fall sharply, returning to levels last seen in the early 2000s. The sector continued to suffer low prices during the late 2010s and through the COVID-19 pandemic in 2020. Oil prices significantly impact LNG prices due to their historical linkage in long-term contracts and their role as competing fuels in various energy markets. Over this period, global investment in the natural gas and LNG sectors fell massively as companies cut capital expenditures due to challenging project economics and squeezed margins. Since then, the industry has had to reset, drive efficiency and carefully manage capital.

Asia spot LNG prices have generally followed similar long-term trends as oil, but with more pronounced volatility, especially in recent years. A strong up-tick in global gas and LNG prices occurred in 2021 due to a combination of factors including: demand recovery from the pandemic, extreme weather conditions, global supply constraints and other logistical disruptions such as shipping availability. LNG prices then surged to a record high of above US$ 35/mmbtu with the outbreak of Russia-Ukraine war in 2022. More recently, warm weather and lower economic growth has softened global gas and LNG prices to nearly pre-COVID levels.

Figure 1 – Real (2025) Brent oil and Asia spot LNG prices



Source: Wood Mackenzie

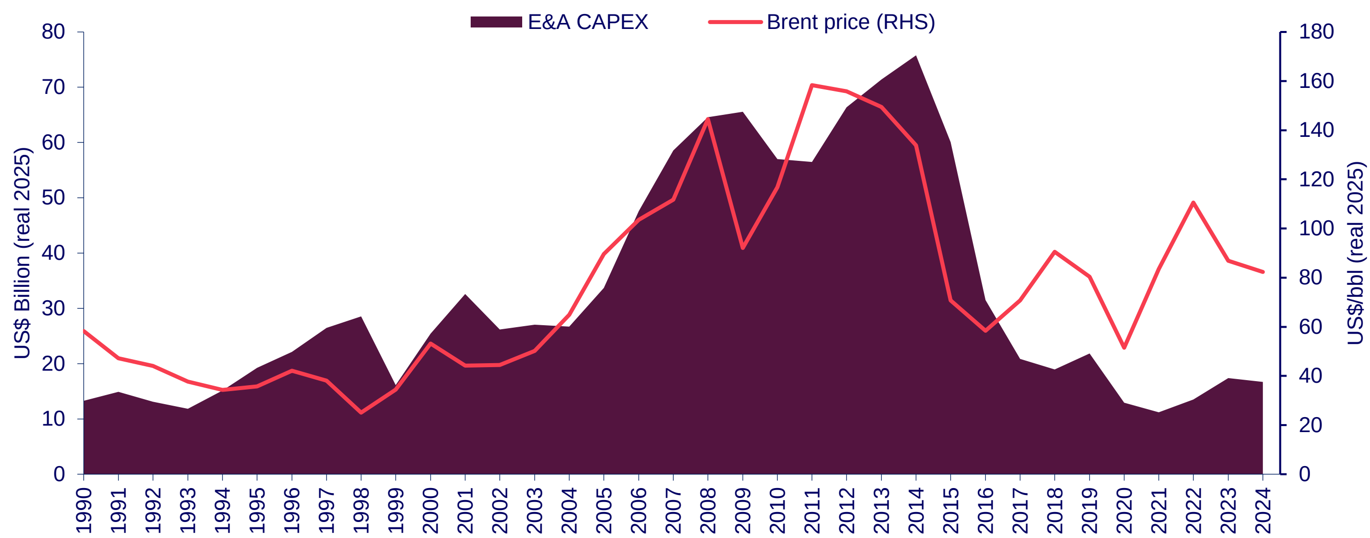
2.1.2. Exploration and appraisal

Investment in oil and gas E&A activity is strongly correlated with commodity prices. Brent oil price gains drive increases in E&A activity, and falls reduce activity. There is a lag between the two, attributable to investors considering whether price movements are structural – driven by supply and demand – or volatility driven by sentiment and short-term events.

To demonstrate this correlation, during the large Brent oil price declines in the mid-2010s, where Brent fell from US$134/bbl (average annual, real 2025) in 2014 to just over US$51/bbl (average annual, real 2025) in 2020 amidst the COVID-19 pandemic, E&A investment across Peer Countries fell from over US$75bn to around US$13bn over the same period.

Whilst oil prices recovered somewhat from their 2020 lows to average above US$80/bbl across 2021 to 2024 (Real, 2025), post-COVID E&A investment across Peer Countries has stayed well below the 2014 peak, though it still tracks in correlation with the increases and decreases in Brent oil prices. Notwithstanding lower overall E&A activity, the industry has still managed to find similar quantities of new resource, and the marginal cost of production has continued to reduce. This is a result of the successful industry transformation that has improved efficiency, lowered costs and “delivered more with less”.

Figure 2 – Peer Countries exploration and appraisal CAPEX, 1990-2024[1]



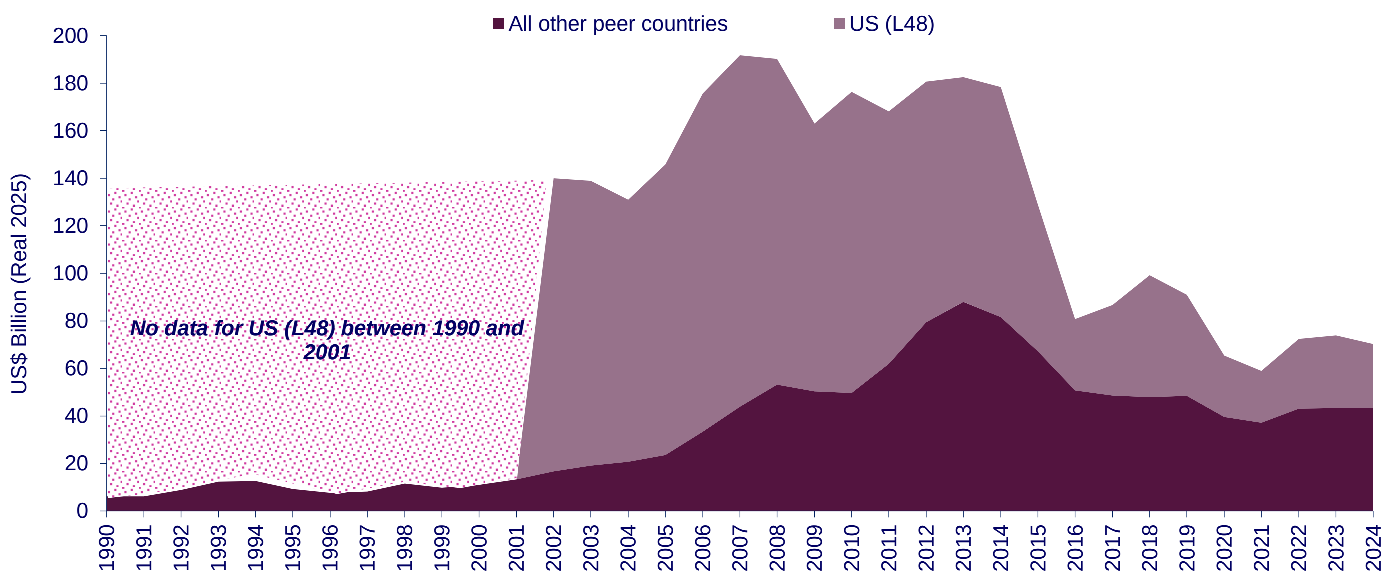
1. Excludes Canada and US L48 E&A CAPEX. Source: Wood Mackenzie.

2.1.3. Upstream gas production

E&A discovers the resources that can subsequently be produced and thus E&A activity can be considered a leading indicator of overall future upstream gas production. Given E&A activity correlates strongly with commodity prices, upstream gas production also correlates with commodity prices, however with a significant lag. The correlation is not as strong as E&A activity, as production also needs to consider overall demand, competing supply and gains in energy efficiency over time.

Investments in upstream gas production peaked prior to the financial crisis of 2008 at over US$190bn (average annual, real 2025) driven by the shale gas boom in the U.S. As commodity prices fell and the COVID-19 pandemic reduced energy demand, upstream investment dropped to less than US$70bn (average annual, real 2025) in 2020. Overall investment in upstream gas production has somewhat increased in the recent years from the lows of 2020, however a fundamental reset in the level of activity has been observed – energy companies are not investing at the levels seen prior to 2014.

Figure 3 – Peer Countries upstream gas production CAPEX, 1990-2024[1]

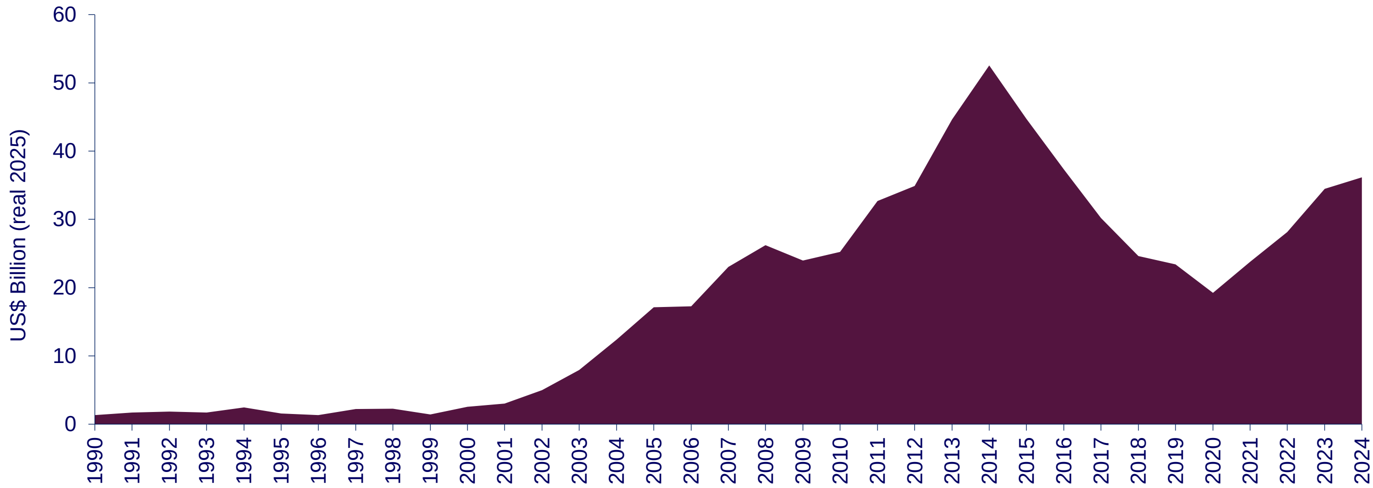


1.1990-2001 data exclude US L48. Source: Wood Mackenzie.

2.1.4. Midstream gas and LNG processing

As the LNG industry has continued to grow, midstream gas and LNG processing investment has increased substantially from less than US$5bn (average annual, real 2025) in the 1990s to a peak of over US$50bn (average annual, real 2025) in the mid-2010s as new waves of LNG projects in Australia and the US approached operations. This was underpinned by robust growth in global LNG demand driven by China and North-East Asia as they switch from coal to gas for energy. This rapid growth in investment and LNG supply coupled with the COVID-19 pandemic led to an oversupply situation that dampened additional investment. Investment during the COVID-19 pandemic in 2020 fell to less than US$20bn (average annual, 2025). However, investment rebounded post-pandemic, as new waves of LNG supply were required to meet forecast future LNG demand, particularly as Europe reduces its reliance on Russian piped gas and switches to LNG imports to meet energy demand.

Figure 4 – Peer Countries midstream gas & LNG processing CAPEX, 1990-2024

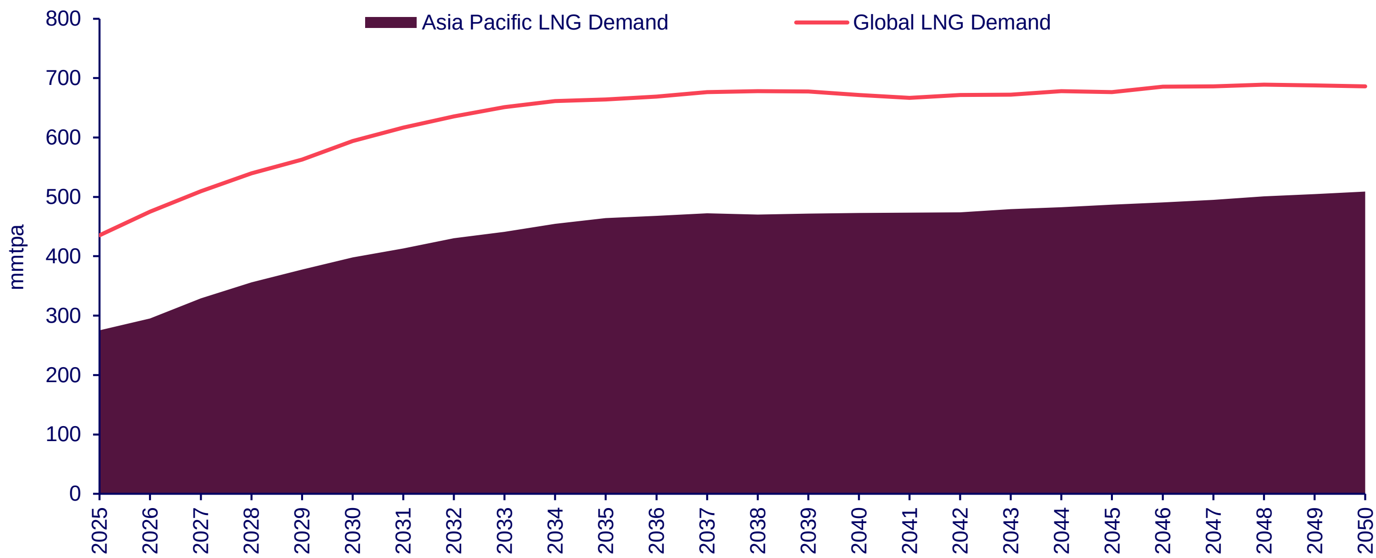


Source: Wood Mackenzie

2.2. Gas and LNG demand continues to grow

Global LNG demand, including Asia Pacific, is set to rise from 435 mmtpa in 2025 to nearly 690 mmtpa by 2050. The Asia Pacific region currently accounts for approximately 63% of global LNG demand and the region's LNG demand is expected to grow at a 2.5% CAGR from 2025 to 2050, eventually comprising nearly 75% of global LNG demand by 2050. Improved LNG affordability, structural declines in domestic gas production in Asian gas producing nations, and decarbonisation policies will drive this long-term growth.

Figure 5 – Global LNG demand, 2025-2050



Source: Wood Mackenzie

In Australia, domestic gas demand is forecast to remain stable in the short to medium term. AEMO expects East Australia residential and commercial gas consumption to decline beyond 2030 but industrial demand to remain relatively flat over the longer term. However, AEMO forecasts gas demand for Gas Powered Generation (GPG) to double between 2025 and 2040. Wood Mackenzie expects GPG will continue to play a crucial role in Australia's electricity markets over the longer term (National Electricity Market – East Australia, Wholesale Electricity Market – south-west of Western Australia and Northern Territory), as well as supporting remote grids, towns and mines (e.g. Pilbara, Goldfields, Mt Isa and Northern Territory regions). GPG's role provides flexible dispatchable power that ensures security of supply and the reliability to support variable renewable energy. The overall resilience of gas demand over the long term means that natural gas will have an important and ongoing role in Australia throughout the energy transition.

2.3. Capital efficiency has improved

The oil price decline from 2014 sent shockwaves through the global energy industry, with particularly significant impacts on the United States' Lower 48 (US L48) shale oil and gas sector. This downturn forced operators to rapidly adapt their strategies and operations to survive in a low-price environment. One of the most notable outcomes of this period was a marked increase in capital efficiency across the industry, as companies sought to maximise returns on their investments and maintain profitability despite reduced revenues. This focus on efficiency and capital discipline was evident across the entire natural gas and LNG value chain – from exploration and appraisal through to LNG production and export.

2.3.1. Exploration & appraisal

In 2015, companies grappled with the new reality of lower oil prices and were forced to reassess their E&A strategies and adapt to a more challenging economic environment. This shift has led to significant changes in how companies approach exploration and appraisal, with a renewed focus on efficiency and capital discipline.

In the immediate aftermath of the price decline, there was a sharp decline in E&A activity across the industry. Companies reduced their exploration budgets, with many reducing spending by 50% or more. This retrenchment was particularly evident in high-cost, frontier areas such as deepwater and Arctic regions. The number of wildcat wells drilled globally fell dramatically, and seismic acquisition activity also saw a significant downturn.

As the industry adjusted to the new price environment, companies began to adapt their E&A programs in several ways:

- **Portfolio Optimisation:** Companies became more selective in their exploration targets, focusing on areas with lower geological risk and shorter time-to-market. Many divested non-core acreage to concentrate resources on their most promising prospects.

- **Near-field Exploration:** There was a shift towards exploring in and around existing producing assets, leveraging existing infrastructure to reduce development costs and accelerate time-to-first-oil.

- **Phased Approach:** Companies adopted more staged exploration and appraisal programs, allowing for incremental investment decisions based on progressive de-risking of prospects.

- **Technology Integration:** Advanced seismic imaging, machine learning, and big data analytics were increasingly employed to improve prospect identification and reduce exploration risk.

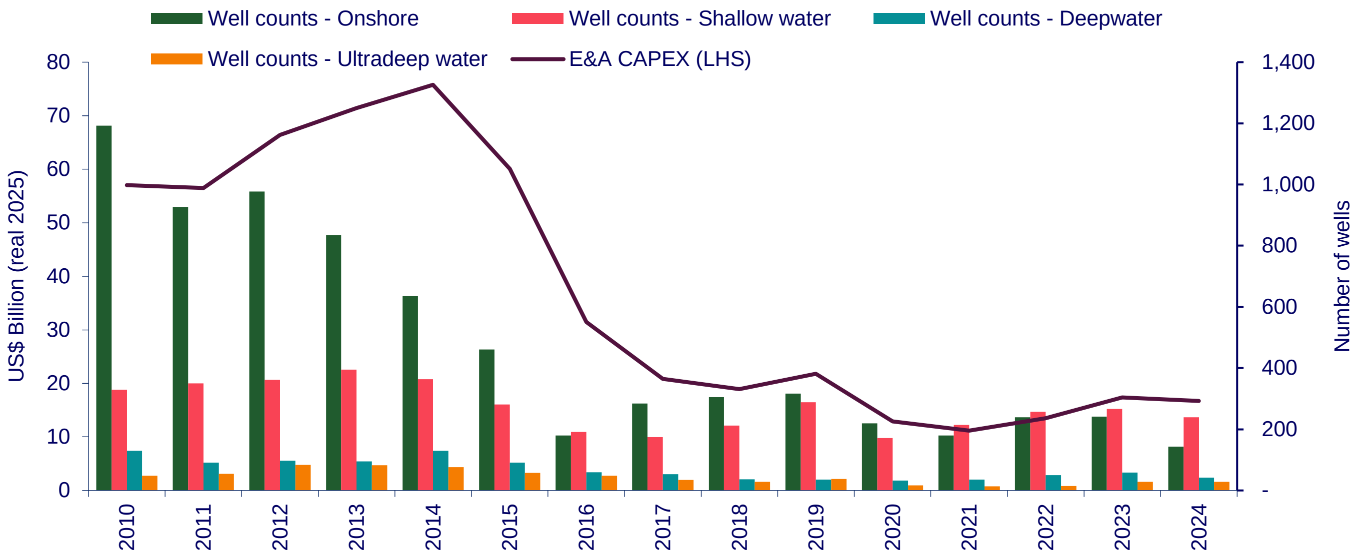
- **Collaboration and Partnerships:** Joint ventures and farm-in agreements became more common as companies sought to share risks and costs associated with E&A activities.

- **Standardisation:** Companies worked to standardise equipment and processes across their E&A programs, reducing costs and improving operational efficiency.

These adaptations have indeed led to increased efficiency in E&A activities. Companies have become more adept at extracting value from their exploration budgets, focusing on quality over quantity in their prospect inventory. The success rates for exploratory wells have improved in many regions, as companies apply more rigorous technical and economic screening criteria before drilling.

However, it's important to note that while efficiency gains have been substantial, they have been accompanied by an overall reduction in the scale of E&A activities with 2021 E&A spend down to a 10-year low of almost US$10bn (Real, 2025). The total number of new discoveries and the volumes of new resources added annually have declined since 2015. This raises concerns about the long-term sustainability of global oil and gas production, particularly as existing fields continue to deplete.

Figure 6 – Peer Countries E&A CAPEX vs Number of wells by Onshore/Offshore, 2010-2024[1]



1. Excludes Canada and US L48 E&A CAPEX. Source: Wood Mackenzie.

2.3.2. Upstream gas production

In the years leading up to 2014, the US shale industry had experienced a period of rapid growth, fueled by high oil prices and readily available capital. However, the oil price decline in 2015 exposed inefficiencies in many operations and prompted a widespread reevaluation of business models. Companies were forced to scrutinise every aspect of their operations, from drilling and completion techniques to supply chain management and organisational structures.

One of the primary areas of focus for improving capital efficiency was in drilling and completion operations. Operators began to implement more advanced technologies and techniques, such as longer laterals, enhanced completion designs, and improved well spacing. These innovations allowed companies to extract more hydrocarbons from each well, effectively reducing the cost per barrel of oil equivalent (boe) produced. Additionally, the adoption of pad drilling and batch completions helped to streamline operations and reduce non-productive time, further enhancing efficiency.

The industry also saw significant improvements in productivity (production per well) through the optimisation of hydraulic fracturing techniques. Companies invested in advanced analytics and machine learning algorithms to fine-tune their fracturing designs, leading to better production rates and ultimate recoveries. This data-driven approach allowed operators to make more informed decisions about where and how to allocate their capital, ensuring that investments were directed towards the most promising opportunities.

Supply chain management became another crucial area for improving capital efficiency. Companies worked closely with their suppliers to negotiate better terms and streamline logistics, reducing costs and improving operational flexibility. Many operators also implemented just-in-time inventory management systems to minimise working capital requirements and reduce waste.

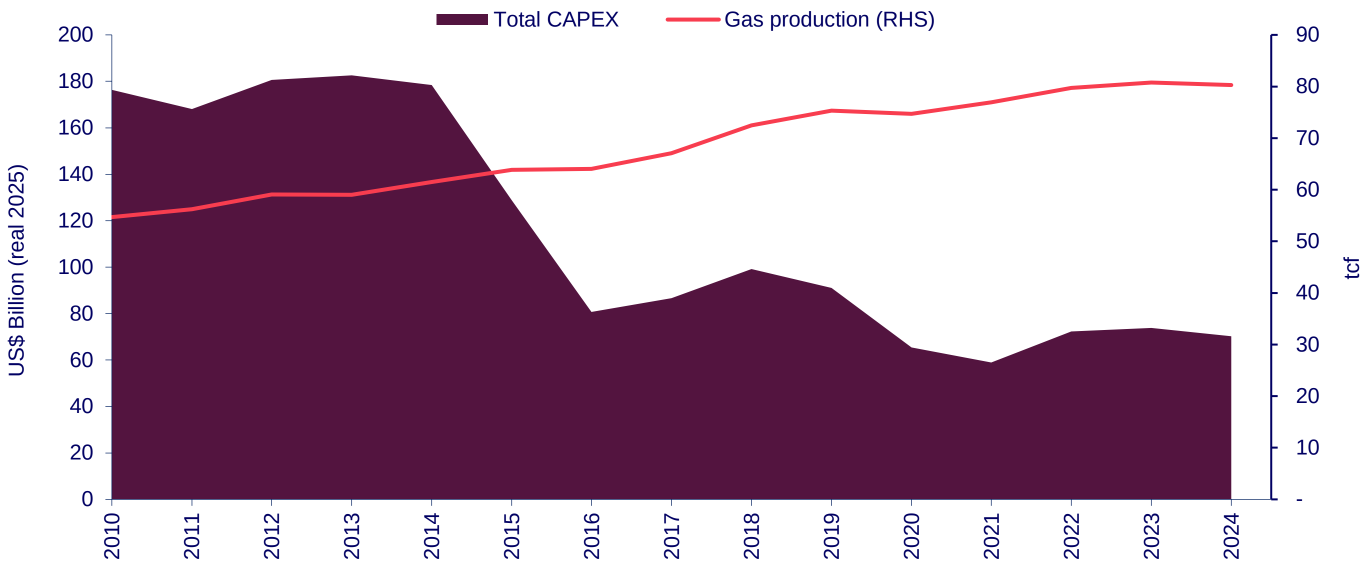
Organisational restructuring played a significant role in enhancing capital efficiency as well. Companies streamlined their operations, reducing headcount and eliminating redundancies. This leaner approach not only reduced overhead costs but also fostered a culture of efficiency and cost-consciousness throughout organisations.

The focus on capital efficiency also led to a shift in how companies approached their acreage positions. Rather than pursuing aggressive land acquisition, operators began to concentrate on their core, most productive assets. This strategy allowed companies to focus their resources on areas where they could achieve the highest returns, divesting non-core assets to improve overall portfolio performance.

Financial discipline became a key tenet of the industry's approach to capital efficiency. Companies implemented stricter investment criteria, prioritising projects with shorter payback periods and higher rates of return. Many operators also adopted a "living within cash flow" mentality, reducing their reliance on external financing and focusing on generating free cash flow.

The results of these efforts were significant. By 2017, many operators had reduced their breakeven prices by 30-50% compared to pre-crash levels. This improvement in capital efficiency not only allowed companies to survive the downturn but also positioned them for profitability in a lower price environment. Over the same period, production has continued to grow despite a halving of total capital spend in upstream gas production across Peer Countries – production grew from approximately 60 tcf in 2014 to more than 80 tcf in 2024.

Figure 7 – Peer Countries upstream gas production CAPEX vs Gas production, 2010-2024



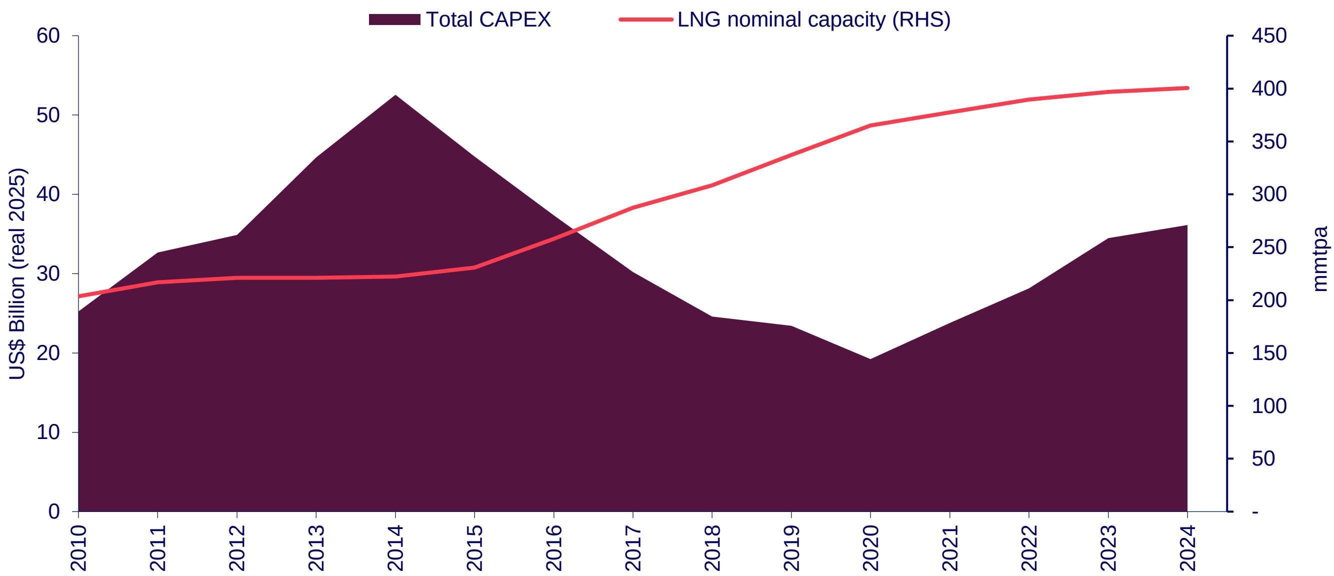
Source: Wood Mackenzie

2.3.3. Midstream gas and LNG processing

Between 2010 and 2014 capital spending on LNG liquefaction projects was robust, driven by strong demand growth, particularly from Asia, and high oil prices. During this period, several large-scale projects were sanctioned, including those in Australia (e.g., Gorgon, Wheatstone, and Ichthys) and the United States (e.g., Sabine Pass and Cameron LNG). Annual investment in liquefaction capacity during these years often exceeded US$30 billion (Real, 2025), with peak years approaching $50 billion (Real, 2025).

The oil price crash of 2015 marked a significant turning point for LNG investments. As oil prices fell, the economics of many proposed LNG projects were severely impacted. This was particularly true for projects with oil-linked pricing structures, which suddenly faced much lower expected returns. Consequently, many Final Investment Decisions (FIDs) were delayed or canceled, leading to a sharp decline in capital expenditure on new liquefaction capacity. Only a handful of projects moved forward – primarily those with robust economics or strong strategic rationales. However, liquefaction capacity continued to grow – increasing from 200 mmtpa in 2014 to 400 mmtpa by 2024.

Figure 8 – Peer Countries midstream gas & LNG processing CAPEX vs LNG nominal capacity, 2010-2024

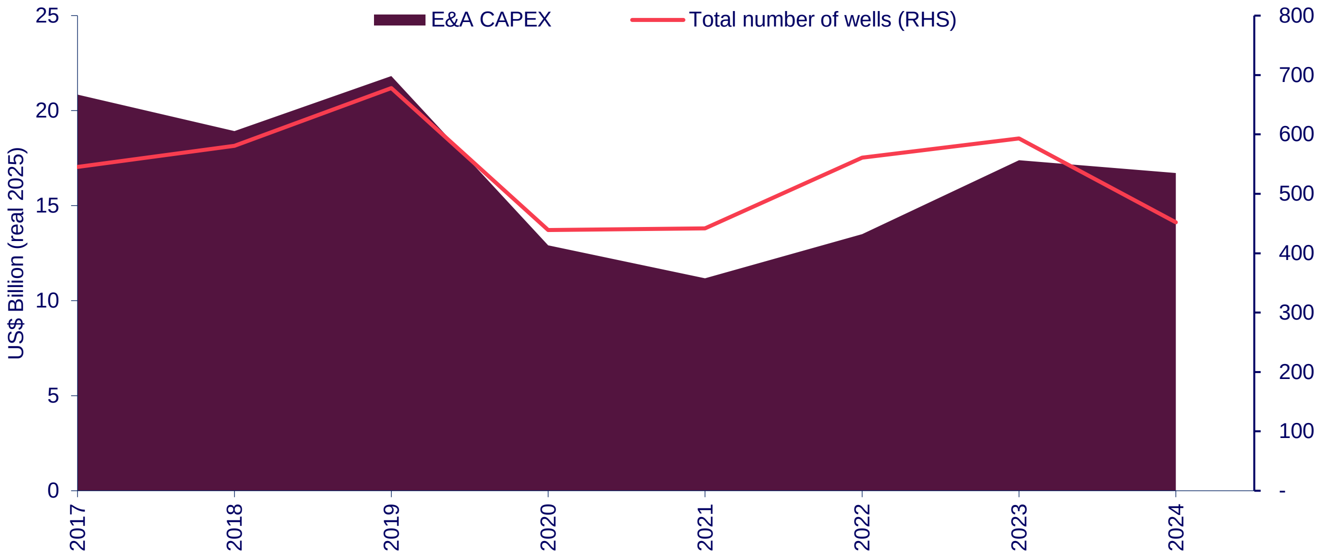


Source: Wood Mackenzie

2.4. Investment is recovering

While overall investment has not recovered to the highs of the mid-2010s, the sector has shown signs of recovery post-COVID-19 pandemic. As oil prices have recovered in recent years, there has been a modest uptick in E&A activity. But companies have largely maintained their focus on capital discipline and efficiency – E&A spend in 2024 remained below US$17bn (Real 2025). The lessons learned during the downturn have become ingrained in corporate strategies, with exploration portfolios now more tightly managed and aligned with broader corporate goals.

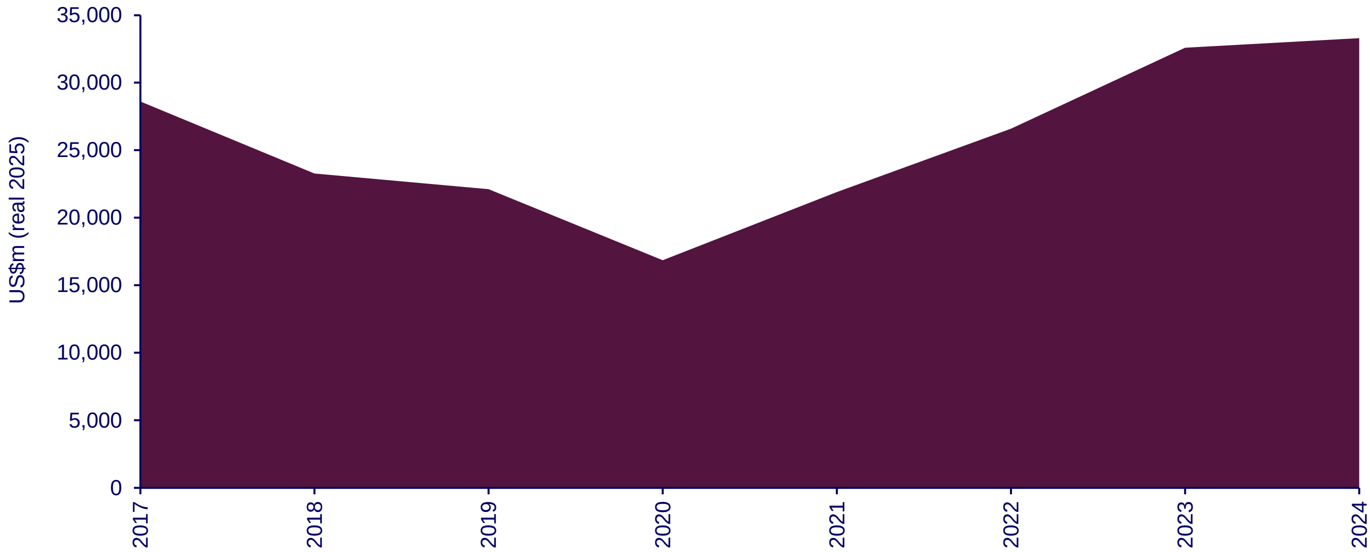
Figure 9 – Peer Countries E&A CAPEX, 2017-2024[1]



1. Excludes Canada and US L48 E&A CAPEX and wells count. Source: Wood Mackenzie

A post-COVID-19 pandemic recovery in LNG liquefaction investment has been marked by a resurgence of project sanctioning and capital commitments, driven by a confluence of factors. As global energy demand rebounded swiftly from the COVID-19-induced slump, the strategic importance of natural gas in the energy transition became increasingly apparent. This, coupled with geopolitical tensions and energy security concerns, particularly in Europe, has bolstered the long-term outlook for LNG demand. Consequently, the industry has witnessed a wave of FIDs for new liquefaction projects, with notable examples including the expansion of Qatar's North Field, the Plaquemines LNG project in the United States, and the resumption of the Mozambique LNG development. Annual CAPEX investment across Peer Countries recovered to more than US$30 billion (Real, 2025) by 2023.

Figure 10 – Peer Countries midstream gas & LNG processing CAPEX, 2017-2024



Source: Wood Mackenzie

3. Investment trends in Carbon Capture and Storage

3.1.1. Carbon Capture and Storage

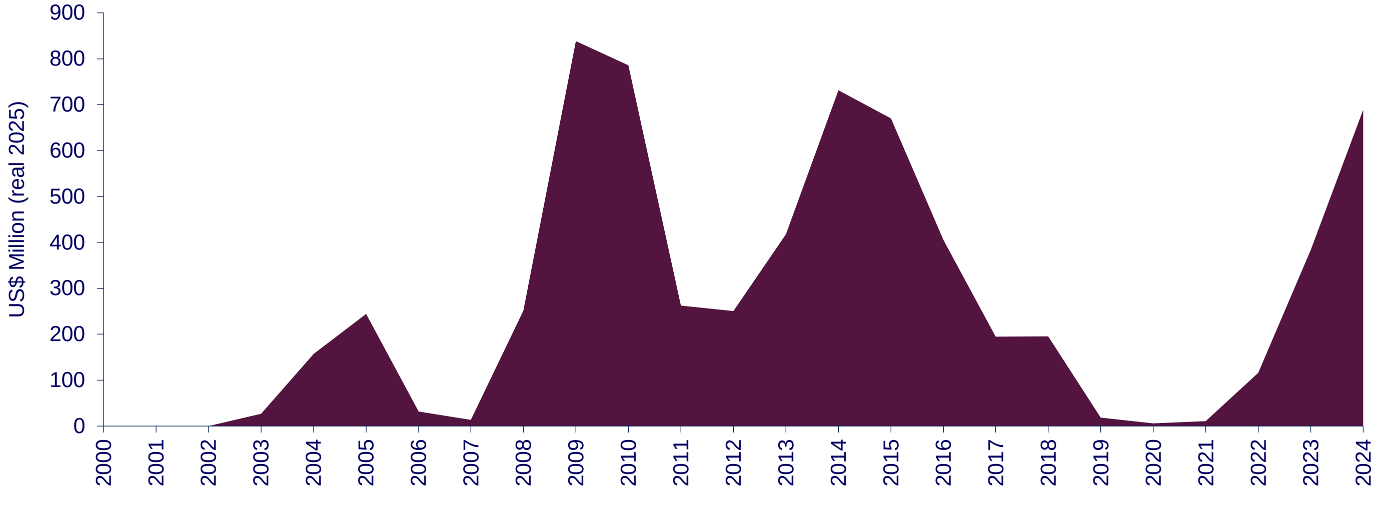
The role of CCS in emissions reduction strategies is likely to grow as hard-to-abate sectors face more stringent emissions controls and regulation. CCS plays a crucial role by capturing the CO_2 emissions, which are then compressed and transported for usage or injection into deep geological formations such as oil and gas reservoirs or saline aquifers. Governments and industries are increasingly recognising the potential of this technology to help achieve ambitious climate targets.

Australia has unique and significant potential to become a key player in CO_2 importation and CCS partnerships, particularly for Asian countries aiming to decarbonise their energy sectors. The country's vast and geologically suitable areas for CO_2 storage, including depleted oil and gas fields and deep saline aquifers, position it as an attractive destination for CO_2 sequestration. Australia's proximity to major Asian economies, coupled with its established energy export infrastructure and expertise in handling large-scale resource projects, provides a strong foundation for developing CO_2 import and storage capabilities. By leveraging these advantages, Australia could offer a valuable service to Asian nations struggling to find domestic storage solutions for their captured CO2, thereby facilitating their transition to cleaner energy systems. However, the success of CCS as a widespread solution will depend on continued technological advancements, supportive policy frameworks, and the development of viable business models that can attract investment and scale up deployment.

Peer Countries' investment in CCS has been volatile over the last two decades, with large increases in investment between 2007 and 2010 led by increasing climate urgency and supportive policy frameworks. The decline in commodity prices and a refocus on core assets across the oil and gas sector put downward pressure on investment from 2015, with the COVID-19 pandemic further reducing investment in the sector.

However, since 2021, Peer Countries' have seen a strong rebound in investment in CCS projects. Geographically, while North America continues to lead in terms of operational projects, there is growing interest and investment in Europe, Asia, and Australia. Projections suggest that cumulative global investment in CCS could reach US$1 trillion by 2050 to align with net-zero emissions scenarios, however the sector is nascent, and it is as yet unclear how it will develop over time. Recent investment (2021 onwards) has been focused on CCS hubs and a repositioning of oil and gas companies to leverage their specialist skills and competitive advantages to pursue CCS as a business that compliments oil and gas production.

Figure 11 – Peer Countries total CCS CAPEX, 2000-2024[1]



1. Includes projects above 0.5 mmtpa capacity, where the emissions source is upstream oil and gas production and midstream gas processing with pre-combustion CO_2 capture. Source: Wood Mackenzie.

3.1.2. Australia's share of CCS investment

Australia has been one of the leading countries in integrated gas/LNG/CCS project development, with two CCS projects (Gorgon and Moomba) currently operating. The Gorgon CCS project, located on Barrow Island off the coast of Western Australia, is one of the world's largest CCS initiatives. Operated by Chevron as part of the broader Gorgon LNG project, it has a design capacity to capture and store up to 4 million tonnes of CO_2 annually. Gorgon CCS project was constructed between 2009 and 2019 as part of the overall Gorgon LNG project. During this period, Gorgon accounted for over 70% of total Peer Countries' CCS investment spend.

The Moomba CCS project began operation in 2024 (developed by Santos and Beach Energy) in South Australia's Cooper Basin. The first phase of the project has a design capacity of 1.7 million tonnes per annum, with potential for expansion in subsequent phases.

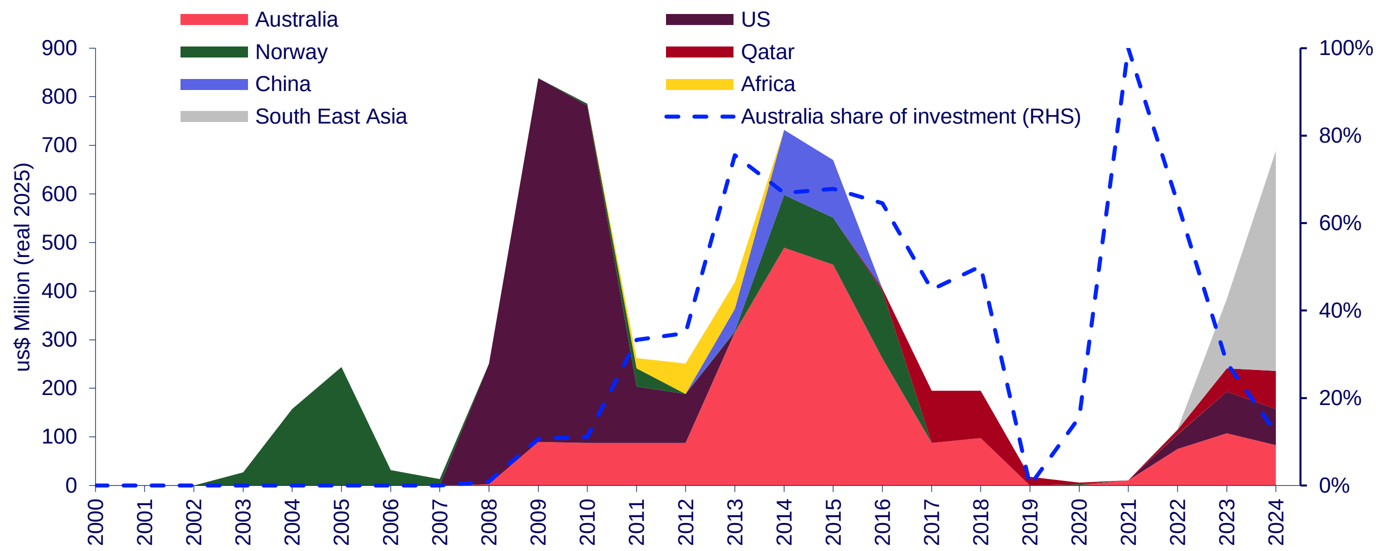
During the peak of construction in 2023, Moomba accounted for over 28% of total Peer Countries' capital investment in the CCS sector.

Outside of these two projects, there are a number of proposals for additional CCS investment, including the development of depleted oil and gas reservoirs as CCS hubs to store local or imported CO_2 from countries with limited domestic geological sequestration options. International regulations for shipping and storage of CO_2 are still evolving – the 2009 Amendment to the London Protocol that permits the export of CO2 streams from a Contracting Party to another country for the purposes of sequestration was a positive development, however it still requires bilateral agreements between countries to be reached before this Amendment enters into force. Governments are actively seeking policy amendments and bilateral agreements to resolve this, with Australia ratifiying the 2009 Amendment to the London Protocol and declaring provisional application of the amendment, allowing the import and export of CO_2 for offshore storage in late 2024. Following the first wave of agreements signed in Europe, Japan and South Korea are set to lead the charge in Asia with export deals for storage, strengthening the roles of Australia CCS sector regionally.

Overall, the CCS industry is still in a very early phase of development. Business models are still being designed, and the logistics of cross-border CO_2 transport are being developed. It is difficult to surmise overall trends in investment between and across Peer Countries at this early stage of the industry's life.

However, it is expected that global CCS investment will grow, and Australia will need to demonstrate strong competitiveness to fight for investment capital in the sector. As CCS is mostly considered an additional cost to industry, achieving competitive costs for CO_2 capture, transport and storage will be critical to successfully growing local capacity. This will require strong Government support for the sector, stable and sensible regulation, a streamlining of project approval processes to ensure projects can be delivered quickly, efficiently and at a competitive cost, and bilateral agreements to be put in place as a matter of urgency to allow for the import and export of CO_2 for storage.

Figure 12 – Australia's share of Peer Countries' CCS CAPEX, 2000-2024[1]



1. *Excludes projects <0.5mtpa nominal capacity. Only includes projects whereby emission source is Upstream oil and gas production and Midstream gas & LNG processing with precombustion capture type. Source: Wood Mackenzie*

3.2. Peer Countries' CCS incentives

The landscape of CCS incentives varies significantly across Peer Countries, reflecting different stages of policy development and national priorities. The United States and Canada have the most comprehensive and financially significant incentives, while Australia is rapidly developing its support mechanisms. In contrast, Indonesia, Malaysia, and Thailand are in the earlier stages of developing their CCS frameworks and incentives.

United States

The United States has implemented one of the most comprehensive and generous CCS incentive programs globally, centered around the 45Q tax credit. The 45Q Tax Credit offers up to US$85 per metric tonne of CO_2 stored geologically, up to US$180 per metric tonne for CO_2 stored geologically from Direct Air Capture, and up to US$60 per metric tonne for CO_2 used in enhanced oil recovery (EOR) or other utilization methods. The credit values increase with inflation and are available for projects beginning construction before January 1, 2033, with a 12-year claim period. The credits are transferable, allowing developers to sell to entities with tax liabilities.

In addition to the 45Q Tax Credit, the United States also provides Department of Energy funding, including grants and funding for CCS research, development, and demonstration projects. At a State-level, various states offer additional tax credits, grants, and regulatory support for CCS projects.

Canada

Canada has implemented a mix of federal and provincial incentives to support CCS development. These include a Federal Investment Tax Credit announced in 2022, offering up to 50% credit for CCS investments. The credit applies to equipment for CO_2 capture, transportation, storage, and use. Additionally, a federal carbon pricing system creates economic incentives for CCS adoption.

Provincial programs provide further incentives; Alberta's Carbon Capture and Storage Fund is a CAD$1.24 billion fund intended to support large-scale CCS projects, and Saskatchewan's Oil and Gas Processing Investment Incentive includes support for CCS in oil and gas operations.

Australia

Australia's CCS incentives are evolving, with CCS able to help covered facilities meet their Safeguard Mechanism obligations and earn Safeguard Mechanism Credits (SMCs). Projects that are not covered by the Safeguard Mechanism may be eligible to earn Australian Carbon Credit Units (ACCUs) under the Carbon Capture and Storage ACCU Scheme method. Australia also launched funding programs such as Carbon Capture Technologies Program (CCTP) to support novel CO_2 capture research and the recent Offshore Greenhouse Gas Storage Acreage Release, which provides opportunities for companies to explore offshore CO_2 storage sites. Of note is that while the CCTP provides for A$65 million in grants, this represents a reduction in funding from the cancelled $250 million CCS Hubs and Technologies Program.

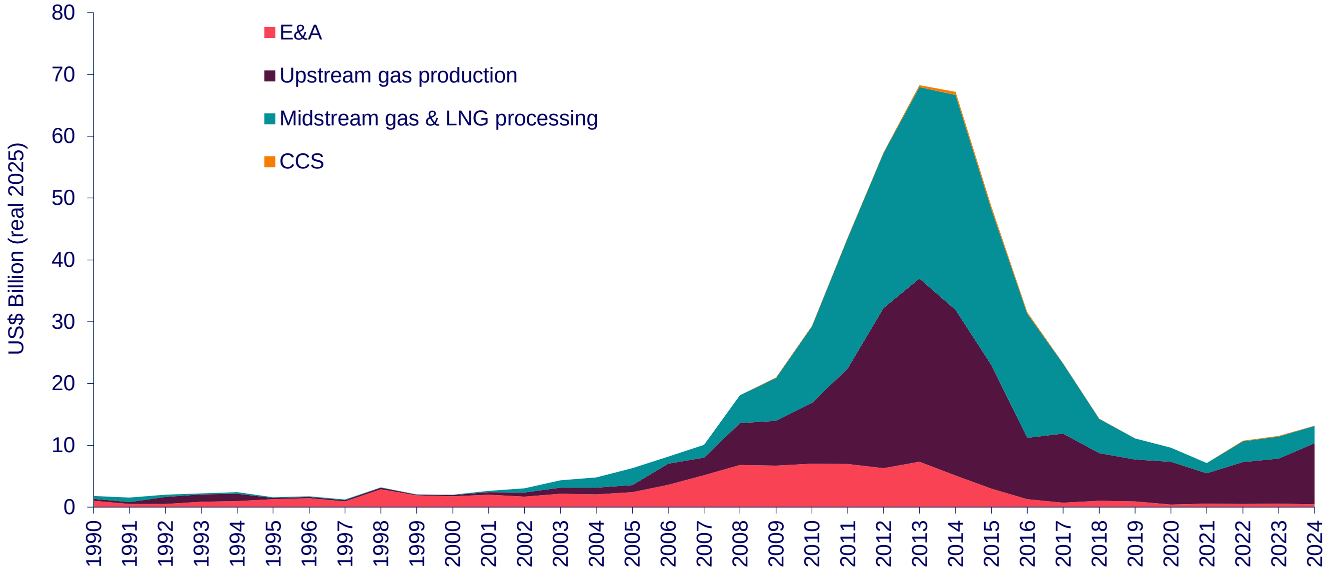
Indonesia, Malaysia, Thailand

Indonesia, Malaysia and Thailand are at various early stages of development of their CCS incentives. These include development national CCS roadmaps and regulatory frameworks, research and development grant programs and discussions of potential tax incentives to support CCS project development.

4. Australia's share of investment

Australia's share of natural gas and LNG investment has seen significant growth since 1990, transforming the country into a major player in the global energy market. In the early 1990s, Australia's share was relatively modest, accounting for between 5% and 10% of Peer Countries' investment in the natural gas, LNG and CCS sectors. However, this began to change dramatically in the early 2000s with the commercialisation of substantial offshore gas reserves and the development of onshore CSG resources. The period from 2009 to 2017 saw an unprecedented boom in LNG investment, with Australia capturing up to 25% of Peer Countries' natural gas and LNG capital expenditure during peak years. This surge was driven by the construction of multiple world-scale LNG projects, including Gorgon, Wheatstone, Ichthys, Prelude and the three CSG-to-LNG projects in Queensland. At its peak, Australian natural gas, LNG and CCS annual investment reached US$70 billion (real, 2025) in 2013 and 2014.

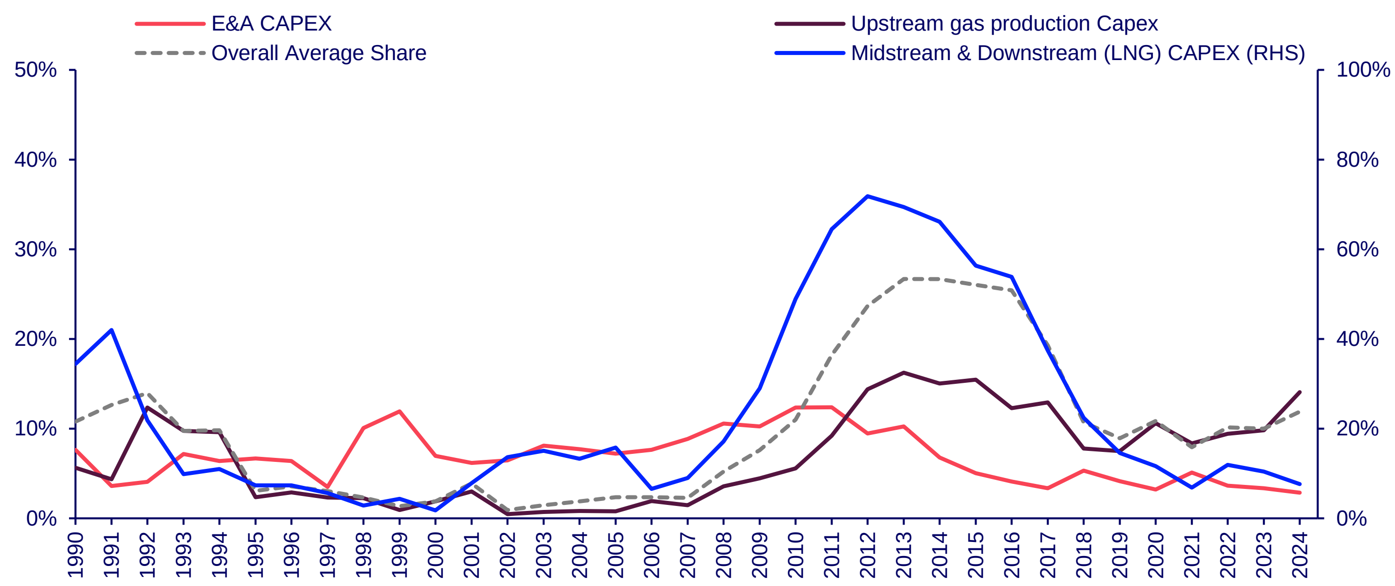
Figure 13 – Total annual natural gas, LNG and CCS CAPEX in Australia, 1990-2024



Source: Wood Mackenzie

By 2019, Australia had become the world's largest LNG exporter, reflecting the massive scale of investment over the preceding decade. The pace of new project development has since slowed, and Australia's share of natural gas, LNG and CCS investment has reverted to its long-term average (~10%), although upstream gas production spend remains robust given the need to continuously backfill the three CSG-to-LNG projects with new wells over time.

Figure 14 – Australia's share of total Peer Countries' natural gas, LNG and CCS CAPEX, 1990-2024[1]



1. Includes CAPEX for E&A (gas wells), upstream gas production, midstream gas & LNG processing and CCS projects. Excludes US L48 and Canada. Source: Wood Mackenzie

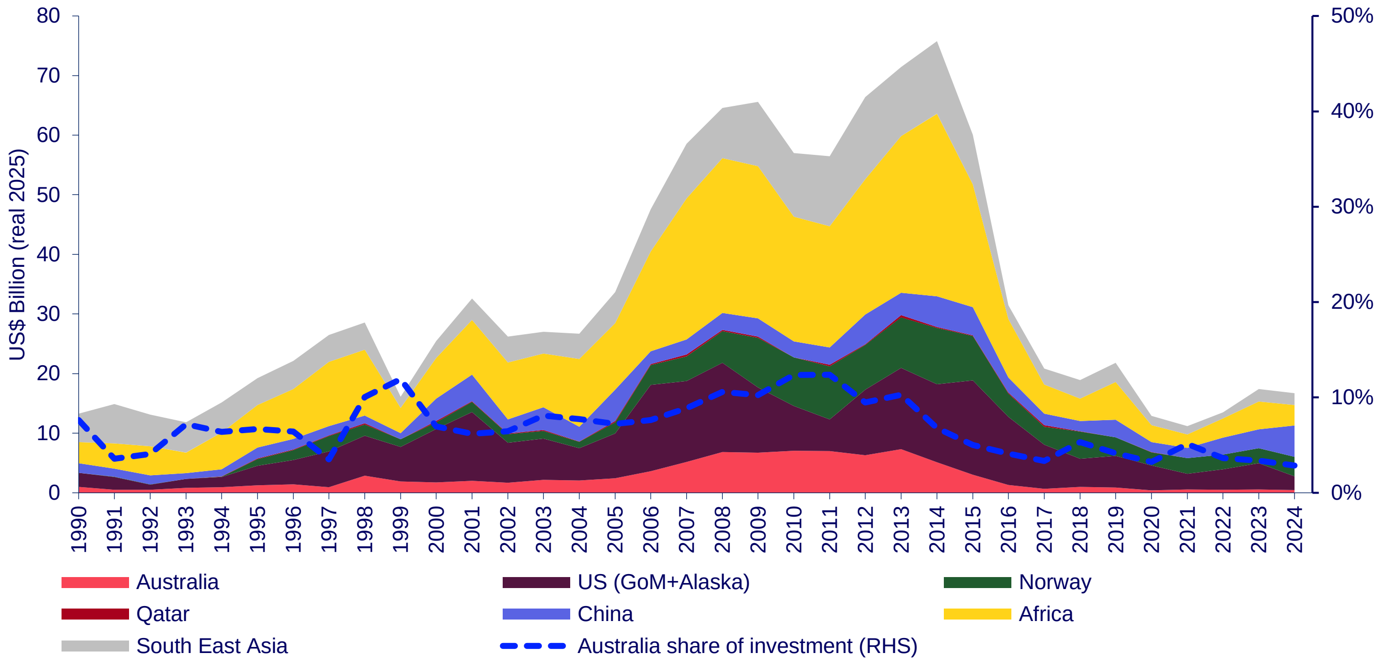
4.1. Long-term share of investment

4.1.1. Exploration & appraisal

In the early 2000s, Australia's share of Peer Countries' natural gas E&A spend was relatively modest, averaging around 5-7% annually. This period saw the initial development of CSG resources in Queensland and the early stages of planning for LNG projects. Australia's share grew between 2005 and 2011, reaching a peak of 12%, driven by large investments in LNG projects in Western Australia and Queensland, exploration of unconventional gas resources – including CSG and shale gas, high global gas prices and strong demand projections from Asian markets.

As major LNG projects moved from exploration to development and production, Australia's share of Peer Countries' E&A spend moderated. Since 2014, Australia has struggled to maintain its long-term average share of Peer Countries' E&A spend, stabilising at approximately 3%. This lower share of E&A activity has been driven by the increasing costs of exploration in mature basins and remote offshore areas, competition from other gas-producing countries, environmental and social license pressures and uncertainty around long-term gas demand in the context of global decarbonisation efforts.

Figure 15 – Australia's share of Peer Countries' exploration & appraisal CAPEX, 1990-2024[1]

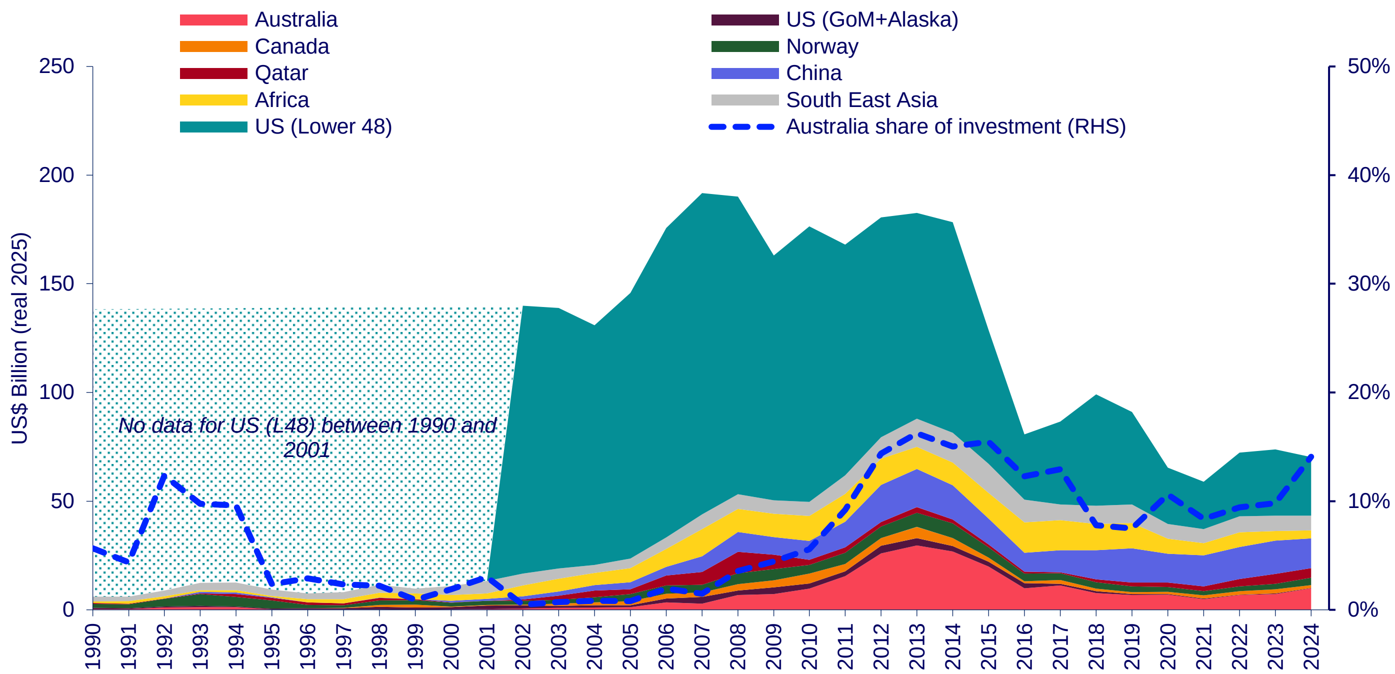


1. Excludes US L48 and Canada. Source: Wood Mackenzie

4.1.2. Upstream gas production

In the early 2010s, Australia saw a substantial surge in upstream gas production investment, driven by the development of major LNG projects. In 2013, Australia's share of Peer Countries' upstream gas production CAPEX reached 16%. Prior to this, Australia's long-term share averaged less than 5%. However, as large-scale projects moved from construction to production, Australia's share began to decline. It has moderated at a slightly higher long-term average since 2017 – approximately 10% of Peer Countries' upstream spend. This is predominantly driven by unconventional gas production requiring continuous well drilling to maintain production, as well as major offshore projects currently under construction offshore Western Australia and the Northern Territory.

Figure 16 – Australia's share of upstream gas production CAPEX[1]

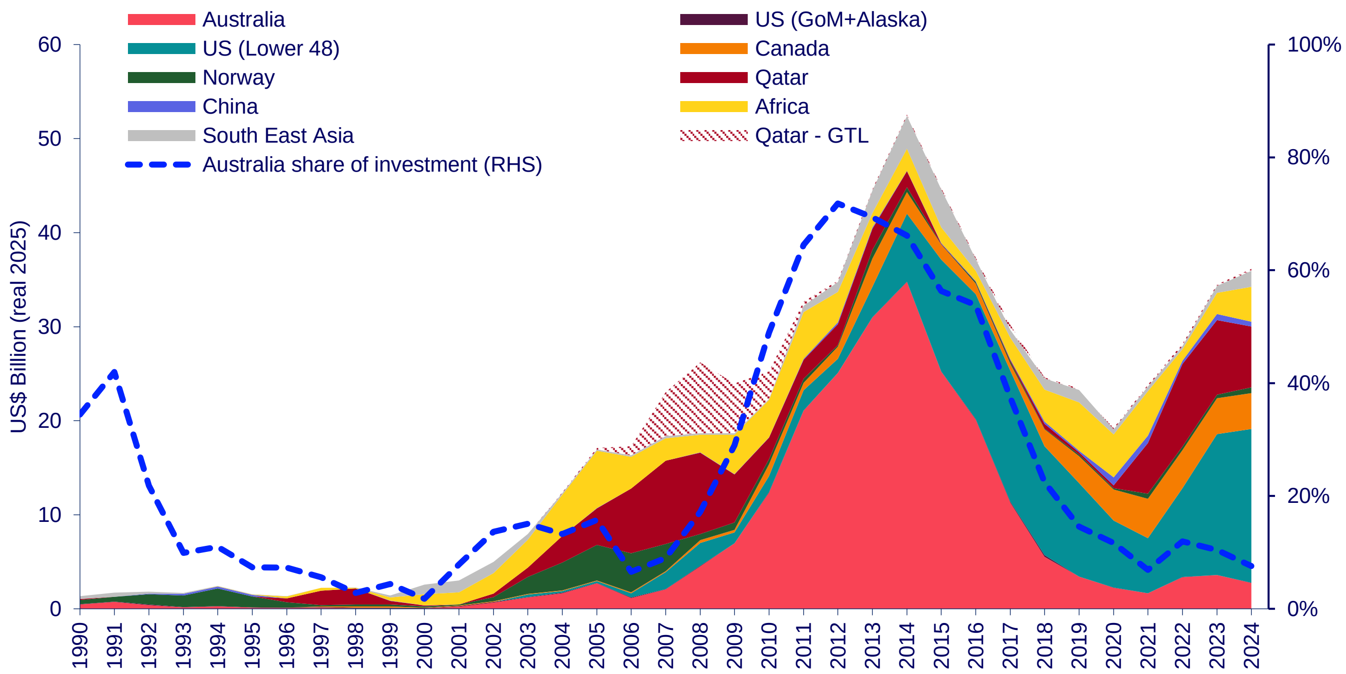


1. 1990-2001 data excludes US L48. Source: Wood Mackenzie

4.1.3. LNG processing

Prior to 2010, Australia's total share of Peer Countries' midstream and downstream LNG processing investment was minimal, with isolated projects in Western Australia and the Northern Territory temporarily raising CAPEX, before spending returned to trend. A major investment surge occurred in the mid-2010s, peaking at over 70% in 2012. However, since then Australia's total share of Peer Countries' midstream and LNG processing CAPEX has demonstrated the most significant decline of any of the major gas value chain elements. Investment in the sector has returned to its long-term average share of less than 10% of that of Peer Countries. This is despite LNG demand continuing to grow, and a substantial recovery in spend across all other Peer Countries following the COVID-19 pandemic (particularly in the United States and Qatar). Whilst Australia led the mid-2010s wave of LNG projects, a subsequent emerging wave is being led by the United States and Qatar, with Australia no longer featuring significantly.

Figure 17 – Australia's share of midstream gas & LNG processing CAPEX

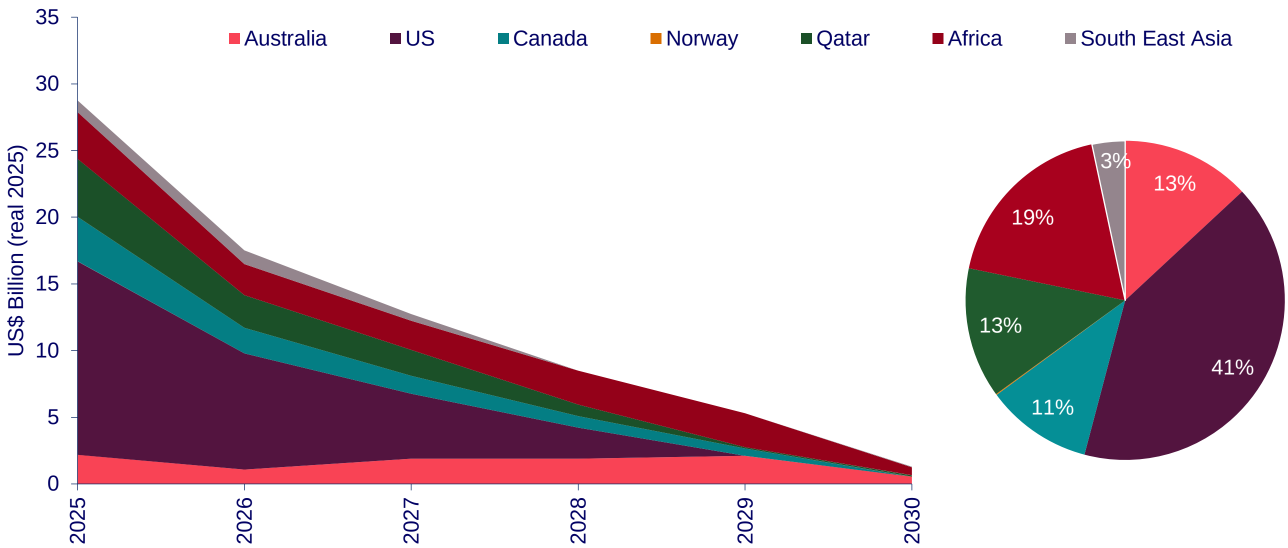


Source: Wood Mackenzie

Over the next five years, the bulk of new investment is anticipated to be led by the United States, with projects including Golden Pass Export, Plaquemines LNG Phase 2, Port Arthur LNG and Rio Grande LNG currently under construction. Total investment in LNG liquefaction capacity in the United States over the next five years is expected to be over US$30bn (real 2025), accounting for 40% of total committed investment across all Peer Countries.

Qatar and Africa also have several projects that are under construction which account for a further 30% share of total committed investments over the next five years. Although Australia's share of Peer Country LNG CAPEX over the next five years is estimated to be approximately 13%, this is predominantly led by incremental LNG capacity expansion and project life extensions or modifications to accommodate new upstream production.

Figure 18 – Committed LNG CAPEX by Peer Country, 2025-2030



Source: Wood Mackenzie

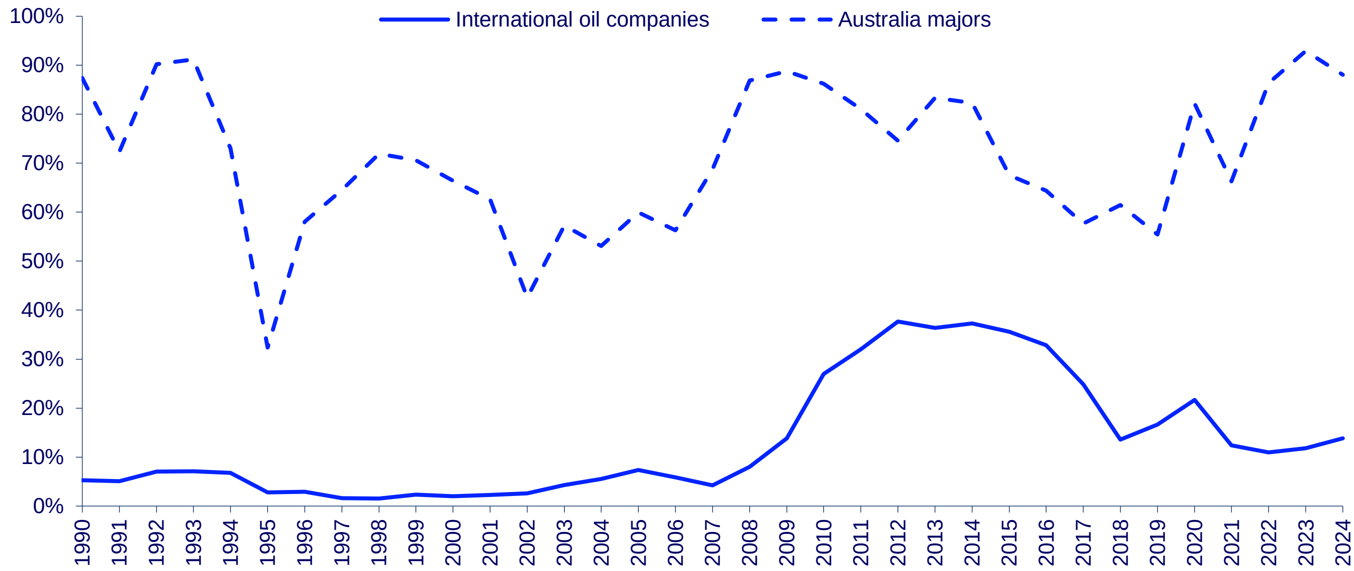
4.2. Australia's share of major investors' portfolios

Australia has managed to attract major international oil company (IOC) investment over the last two decades, establishing itself as a key player in the global energy market. Large reserves of oil and gas, a strategically advantaged location and relative safety and stability has made Australia an attractive destination for exploration, gas production and LNG investment. As a result, most major IOCs have natural gas and LNG assets and operations in Australia. In addition, Australia has produced two domestic energy companies that have grown to be major international oil, gas and LNG producers with broad portfolios across a range of countries.

Major IOC investment in Australia surged from the early 2010s, peaking at nearly 40% of their combined overall portfolios resulting from significant investment in various Australian LNG projects. Since then, with the pace of new project development slowing down, Australia's share of IOC portfolios has fallen to an average of approximately 15% over the past 5 years. Upstream gas production spend remains robust as a share of total portfolio; however, this reflects both the need to continuously backfill Australian LNG plants with new upstream production, and a decreasing overall upstream gas production spend in Peer Countries. In contrast, the two Australian majors have increased their investment in Australia over the last five years. Woodside's additional investments in the Scarborough/Pluto expansion projects and Santos's investments in the Barossa-Caldita fields have driven this growth.

Looking forward, however, the trend is much starker – both the IOCs and Australian majors have significantly reduced their investment in Australian E&A. The major IOCs have committed just 1.2% of their global E&A investment to Australia over the last five years. The Australian majors, who have domestic market obligations and a natural competitive advantage in Australia, have invested an average of only 15% of their total E&A spend in Australia over the same period. This compares to a long-term average of over 42% of total portfolio E&A spend between 1990 and 2019. Given E&A activity can be considered a leading indicator of overall future upstream gas production, it is possible that Australia's share of both the IOCs and domestic major portfolios could fall further in the longer term.

Figure 19 – Australia's share of companies' natural gas and LNG CAPEX, 1990-2024[1]



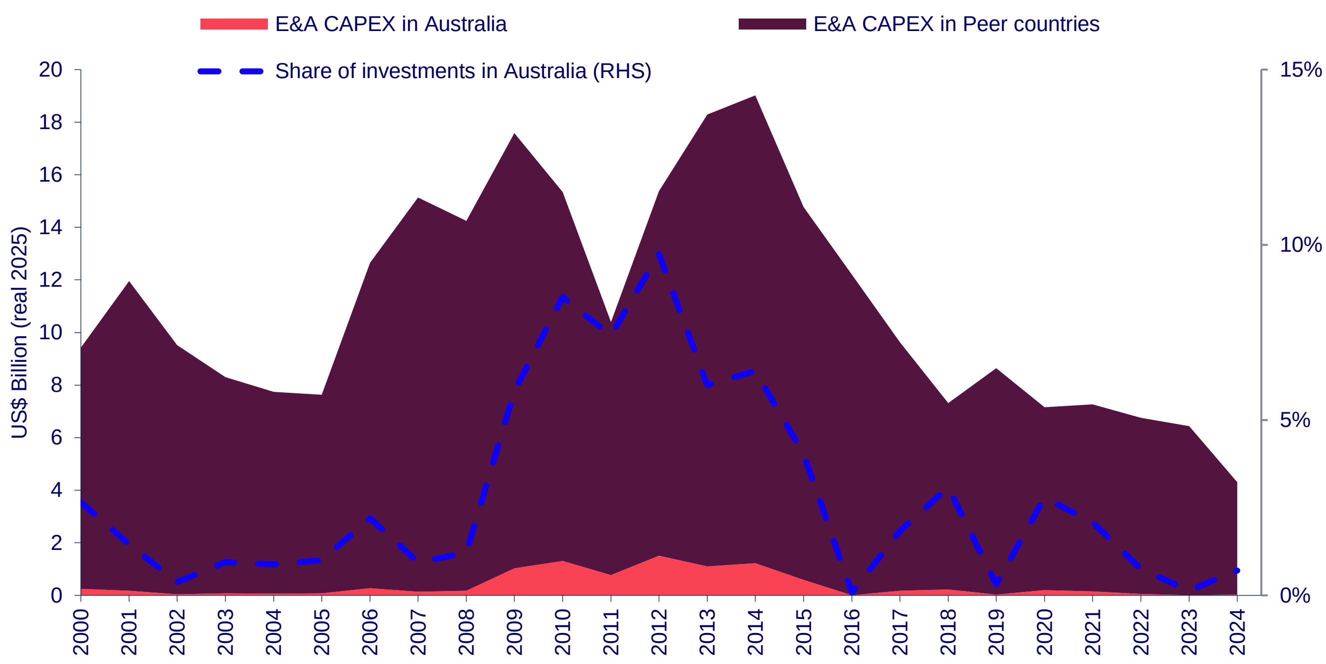
1. Includes CAPEX for E&A, upstream gas production, midstream and downstream gas processing (LNG) invested globally. E&A CAPEX excludes US L48 and Canada. Source: Wood Mackenzie.

4.2.1. International Oil Companies

Exploration and Appraisal

The Australian share of IOC E&A investment was relatively modest in the early 2000s, averaging around 1-3% annually. This grew between 2008 and 2012, reaching a peak of 10% of total portfolio E&A as the majors invested in the unconventional CSG plays on the east coast. Additional investment included Western Australia's North Carnarvon and Browse basins, underpinned by planned LNG liquefaction projects. As major LNG projects moved from exploration to development and production, Australia's share of IOC E&A investment has returned to pre-2009 averages of approximately 1% of total portfolio E&A spend.

Figure 20 – International oil companies' E&A CAPEX[1]

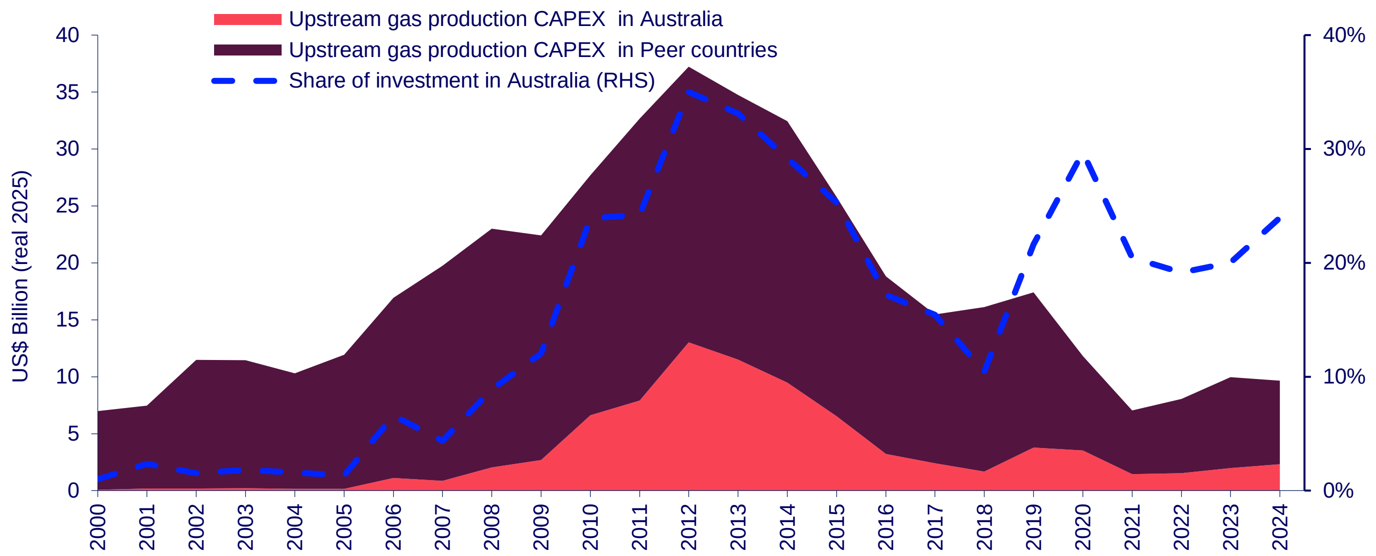


1. Excludes U.S L48 and Canada. Source: Wood Mackenzie

Upstream gas production

Prior to 2005, IOCs had minimal investment in Australian upstream gas production. In conjunction with a surge in E&A spend after 2008, upstream gas production investment quickly followed, with Australian upstream spend accounting for almost 35% of overall portfolio production spend. This investment in upstream production was dominated by two Western Australia LNG projects. After 2012, upstream gas production investment started to decline, but it maintains a higher average portfolio share as a result of ongoing drilling to backfill CSG production. Between 2020 and 2024, Australia's share of IOC upstream gas production investment averaged 20% of total portfolio spend.

Figure 21 – International oil companies' upstream gas production CAPEX

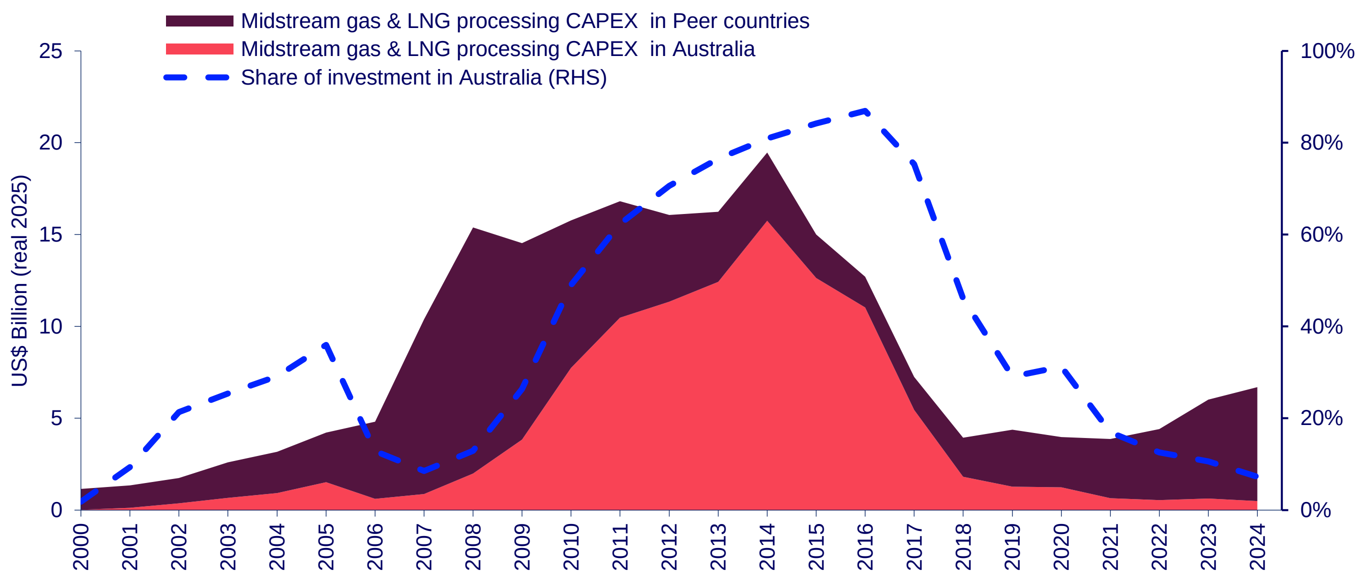


Source: Wood Mackenzie

Midstream, Downstream and LNG

Almost all IOCs have stakes in Australian LNG liquefaction projects, with many being operators of either the upstream fields, downstream plants, or both. Given their involvement in Australia LNG projects, IOCs have invested heavily across midstream and downstream LNG processing. In 2016, this investment reached a peak, with almost 90% of all IOC spending in downstream and LNG processing occurring in Australia. As the projects reached operation, Australia's share of investment declined. Over the last five years, it has continued to decline, with Australia now attracting less than 10% of total IOC portfolio spend in the downstream and LNG processing sector. This is despite overall IOC investment growing, led by LNG projects in the United States, Qatar and West Africa.

Figure 22 – International oil companies' midstream gas & LNG processing CAPEX



Source: Wood Mackenzie

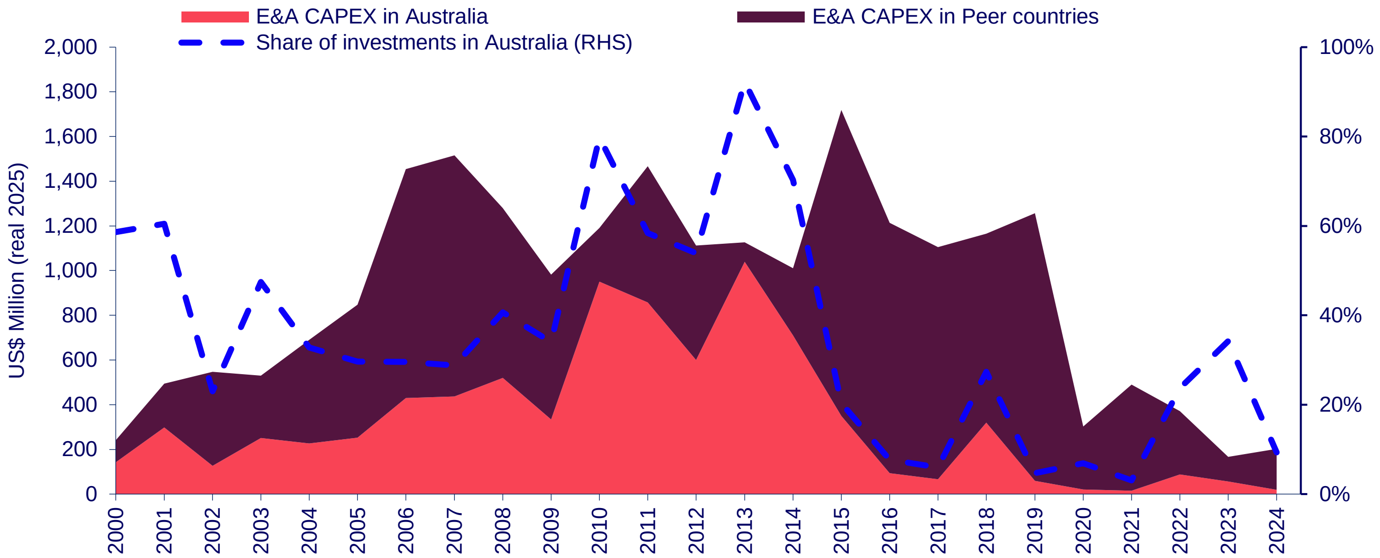
4.2.2. Australian majors

Exploration and Appraisal

Australia's two leading natural gas producers have evolved from domestic-focused companies to international players with diverse portfolios. Average E&A spend has historically been domestically focused, and averaged approximately 50% of total E&A spend between 1990 and 2015. However, both companies have pursued broader growth and have acquired international assets and operations over a number of years. In line with industry trends, E&A investment fell in absolute terms after 2015. At the same time, however, the share of E&A investment in Australia also fell – since 2016, both companies have averaged an E&A spend in Australia of only 15% of total investment.

Whilst this may appear as though the Australian majors are demonstrating a pivot away from Australian exploration activity, this reflects the changing nature of their portfolios, with mergers and acquisitions adding substantial international assets and acreage to both businesses.

Figure 23 – Australian majors' E&A CAPEX[1]

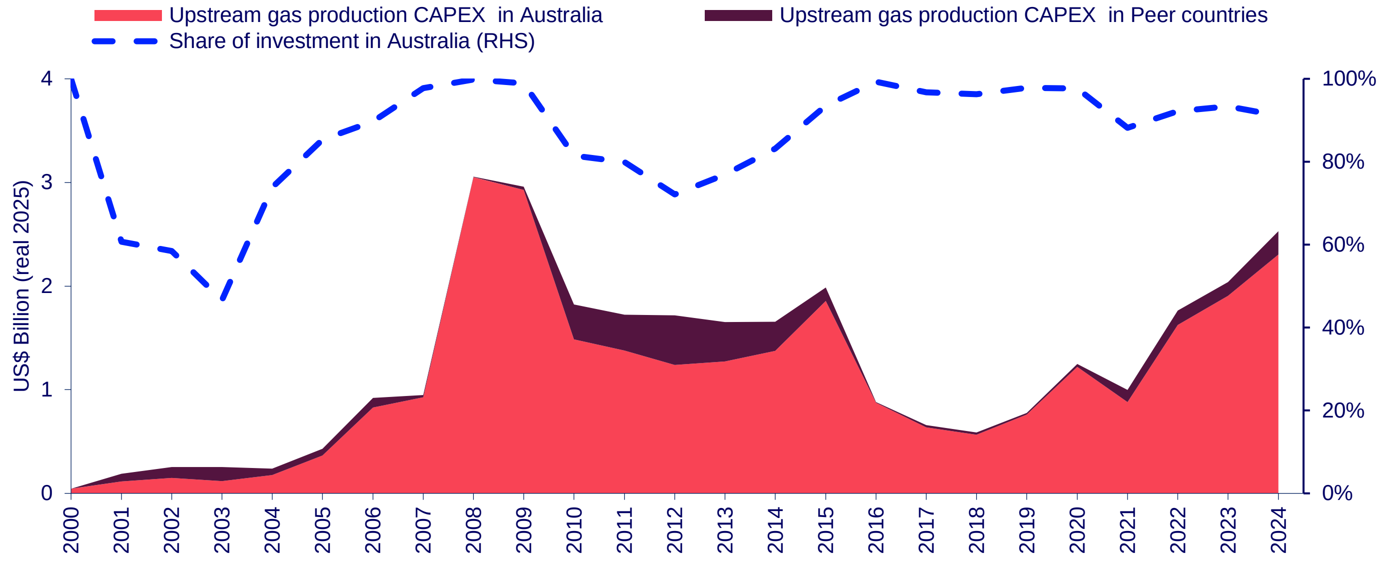


1. Excludes U.S L48 and Canada. Source: Wood Mackenzie.

Upstream gas production

Upstream investment remains robust, with the Australian majors continuing to invest close to 100% of their upstream gas production budgets in Australia. From the early 2010s, both companies diverted some of their investment to South-East Asia and the US, with Australia's share dropping to less than 75% in 2012. In recent years, although some investment remains outside of Australia, the domestic upstream investment is consistently over 90% of total spend. On the East Coast this is led by continuous CSG drilling to backfill CSG-to-LNG plants, and on the West Coast it is driven by new and expansion projects offshore to provide feed-gas to existing LNG facilities into the future.

Figure 24 – Australian majors' upstream gas production CAPEX

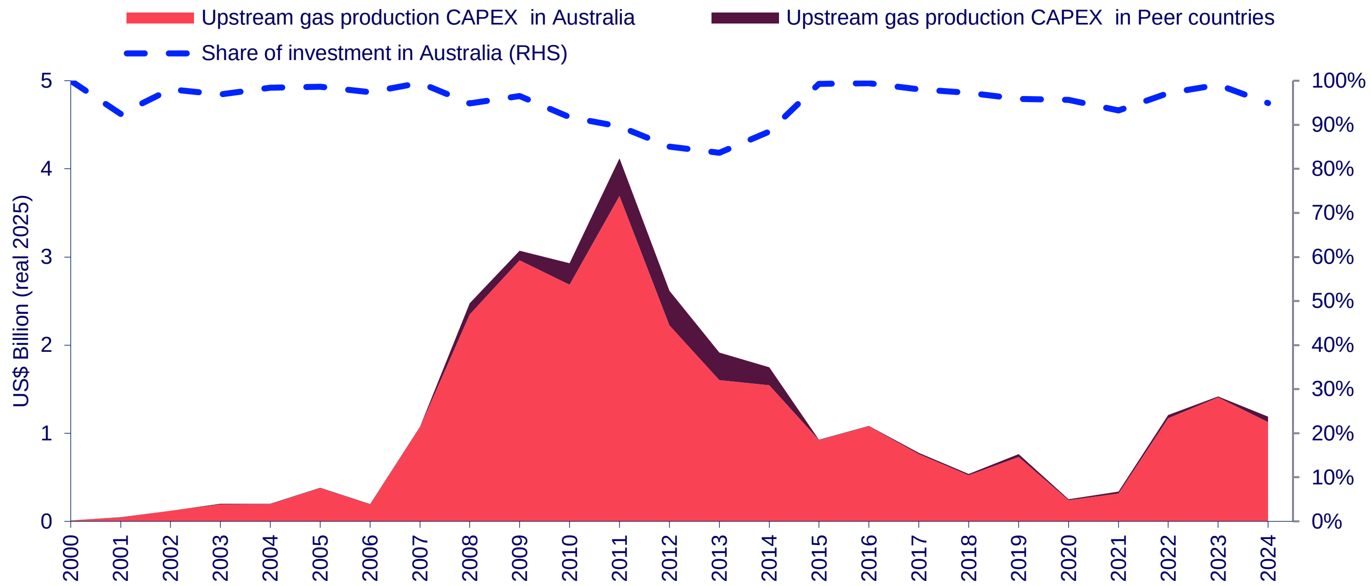


Source: Wood Mackenzie

Midstream, Downstream and LNG

Australia's majors predominantly invest in Australian LNG liquefaction facilities. Projects in Western Australia, the Northern Territory and Queensland dominate their portfolios and resulting domestic investment share. Both have since acquired international LNG liquefaction projects – in the United States, Papua New Guinea and Africa – which means that future LNG spending will likely occur outside of Australia, and the local share of LNG investment will decline.

Figure 25 – Australian majors' midstream gas & LNG processing CAPEX



Source: Wood Mackenzie

4.3. Recent trends

Over the past decade, Australia has seemingly experienced a decline in its attractiveness as a destination for investment capital in the natural gas and LNG sector. The country, which once led the world in LNG investment and development, has seen its appeal wane as competitor countries have expanded their investment and domestic challenges have mounted.

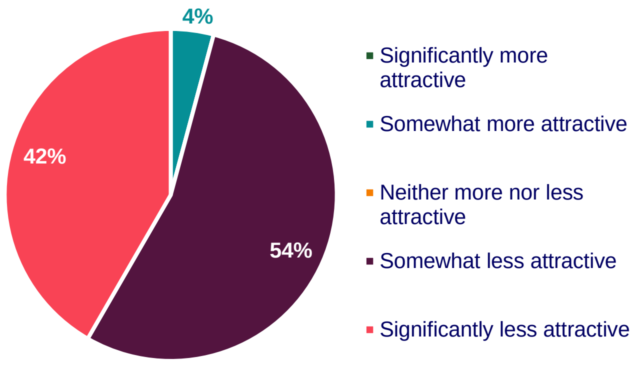
A number of elements must be considered when analysing whether Australia's share of investment in the natural gas and LNG sectors has declined, and what may be the cause. Whilst Australia has a reputation for high labour costs, and gas and LNG projects are often located in remote areas that drive up cost and complexity, these factors are nothing new. Nor has Australia's geological prospectivity materially changed – the country still boasts large remaining reserves / resources and relatively high exploration success rates.

Factors such as policy uncertainty surrounding energy and climate change issues, an unstable and interventionist regulatory environment, cost inflation, the ability to obtain and maintain social license and ongoing debates about resource taxation and local content requirements must all be considered.

The prevailing sentiment is that Australia is less attractive to investors with global portfolio options, and recent historic data and trends appear to support this notion. This policy uncertainty also translates to higher risk and cost for Australia-only gas explorers/developers.

A survey of Australian Energy Producers members revealed that 95% of respondents believe Australia has become a Significantly or Somewhat Less Attractive place for their company to invest in over the last 5 years. Only 4% believed the investment environment had become Somewhat More Attractive, and none considered it had become Significantly More Attractive.

Has Australia become a more attractive or less attractive place for your company to invest in, over the last 5 years?



4.3.1. Exploration is recovering, but not in Australia

As outlined in this report, many companies reassessed their capital expenditure plans in 2015, leading to a sharp reduction in exploration budgets worldwide. Australia, with its relatively high-cost operating environment, was particularly vulnerable to these market shifts. Concurrent with global market pressures, Australia experienced a period of policy uncertainty regarding energy and climate change. The ongoing debate surrounding emissions reduction targets, carbon pricing mechanisms, and the role of fossil fuels in the nation's energy mix created an atmosphere of caution among investors. This uncertainty deterred long-term commitments to E&A projects, as companies sought clarity on the regulatory landscape.

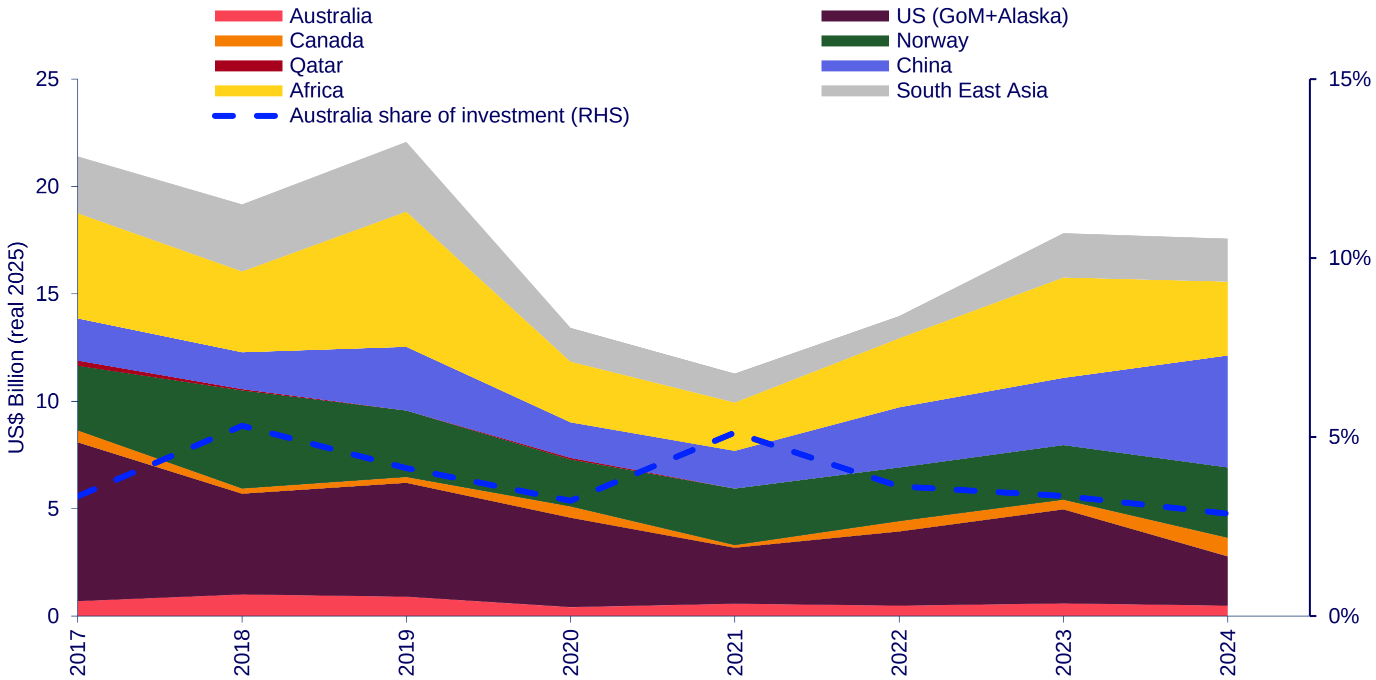
The global E&A sector experienced a notable recovery in investment following the COVID-19 pandemic, marking a significant turnaround. This resurgence was primarily driven by a combination of factors, including rebounding oil and gas prices, improved market sentiment, and a strategic refocus on securing future energy supplies. Major oil and gas companies, having strengthened their balance sheets through cost-cutting measures during the downturn, cautiously resumed their E&A activities, with a particular emphasis on near-field exploration and high-impact prospects in proven basins. The recovery was further bolstered by national oil companies in key producing regions, who maintained or increased their E&A budgets to ensure long-term production sustainability.

Notably, there was a discernible shift towards natural gas exploration, reflecting its perceived role in the energy transition. While the recovery was not uniform across all regions, with some areas seeing faster rebounds than others, the overall trend indicated a renewed confidence in the sector.

But Australia did not follow this trend. E&A activity and associated investment in Australia has remained at very low levels since 2018 despite the global recovery. The time and cost associated with environmental regulations and lengthened approval processes for exploration permits have discouraged some operators from pursuing new ventures, particularly in frontier basins. Additionally, the Annual Acreage Release Program was effectively stopped in 2023 as the Australian government announced it would not proceed with the 2023 offshore petroleum exploration acreage release. The decision was part of a broader review of Australia's oil and gas policy, considering the country's emissions reduction targets and the need for an orderly transition in the energy sector. The acreage release program is expected to restart in 2025.

As E&A activity has remained at historically low levels for almost a decade, Australia has experienced a gradual erosion of its skilled workforce in the sector. Many experienced professionals have either retired or transitioned to other industries, creating a skills gap that is further hampering exploration efforts.

Figure 26 – Australia's share of Peer Countries' E&A CAPEX, 2017-2024[1]



Note: 1. Excludes U.S L48 and Canada. Source: Wood Mackenzie

4.3.2. Australia has maintained CAPEX investment in upstream

Investment in upstream gas production has been increasing since 2021 across all Peer Countries. In Australia, despite falling investment in LNG production and very low levels of E&A activity, investment in upstream gas production doubled between 2021 and 2024 – from approximately US$6.5bn (average annual, real 2025) to over US$12bn (average annual, real 2025).

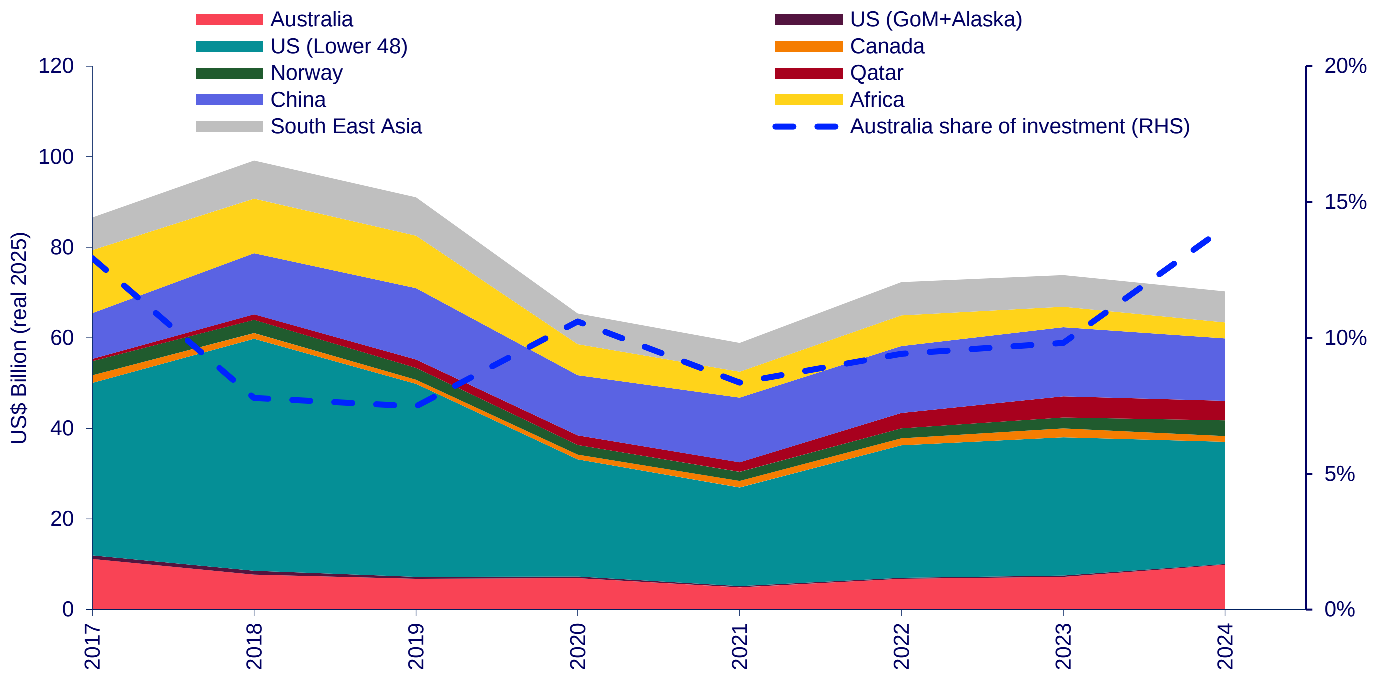
There are a number of factors in the Australian natural gas sector that may be driving this growth:

- Australia's east coast predominantly produces unconventional coal seam gas, which requires sustained and relatively high upstream CAPEX spends (compared to conventional plays) to maintain production as existing wells decline.

- The majority of Australia's natural gas investment over the last decade has focused on leveraging existing infrastructure and backfilling existing LNG facilities with new upstream supply to maintain utilisation rates.

- Comparatively high well costs for offshore conventional gas projects currently under construction.

Figure 27 – Recent trends in upstream gas production CAPEX



Source: Wood Mackenzie

4.3.3. Peer Country LNG investment rebounded, but Australia's share continued to decline

The period from 2021 to 2024 marked a significant rebound in Peer Country investment in LNG liquefaction capacity. The recovery from the COVID-19 pandemic played a pivotal role in reinvigorating LNG investment. As economies reopened and industrial activity rebounded, energy demand surged, particularly in Asia. This demand growth, coupled with a renewed focus on energy security, created a favorable environment for LNG projects.

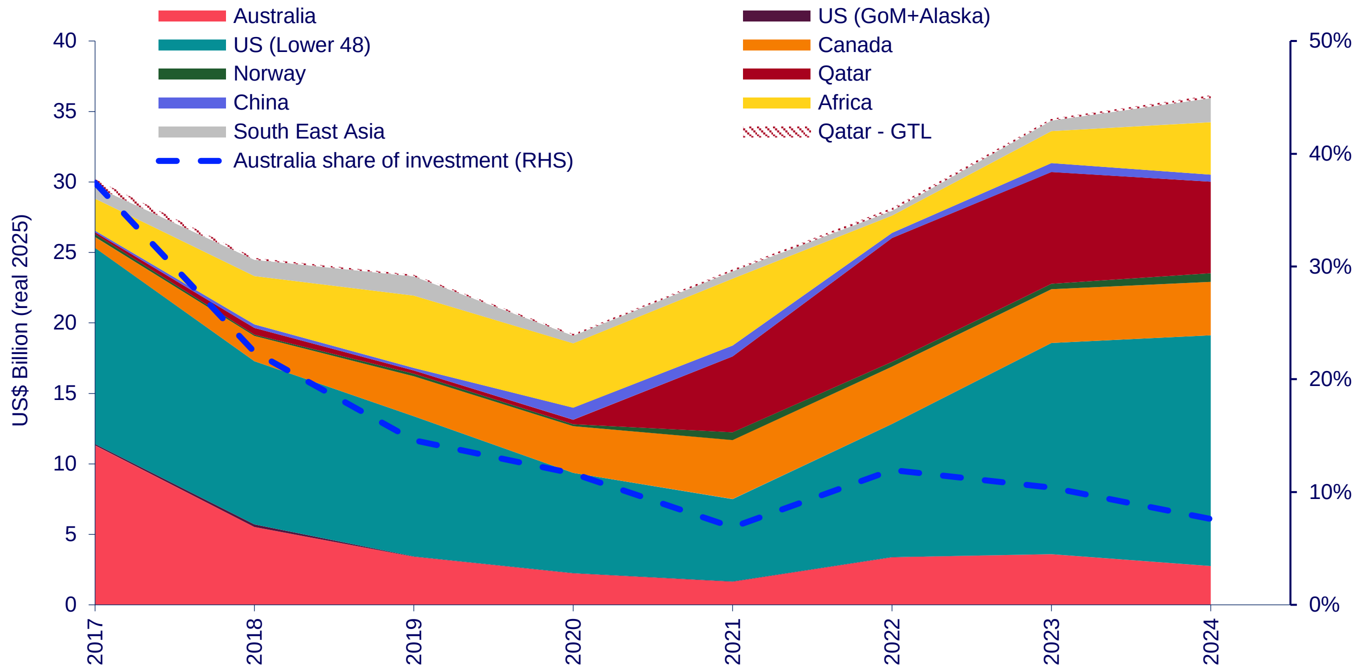
The global push towards decarbonisation further bolstered the case for LNG investment. Natural gas, viewed as a cleaner alternative to coal and a complement to intermittent renewable energy sources, gained prominence in many countries' energy transition strategies. This positioning of gas as a "bridging fuel" provided a strong rationale for expanding LNG capacity.

Additionally, the geopolitical landscape – particularly the Russia-Ukraine conflict that escalated in 2022 – dramatically altered global energy flows. European countries, seeking to reduce dependence on Russian pipeline gas, turned increasingly to LNG. This shift created new market opportunities and spurred investment in liquefaction projects aimed at serving European demand.

The result of this demand-side led recovery meant that LNG prices rose significantly from their 2020 lows, improving the economics of liquefaction projects. The spike in gas prices in Europe and Asia in late 2021 and throughout 2022 further enhanced the attractiveness of LNG investments, as the potential for high returns became more apparent. Several key LNG-exporting and importing countries implemented policies to support LNG development. This included streamlined regulatory processes, tax incentives, and in some cases, direct government investment or guarantees. Such policy support was crucial in facilitating FIDs on major projects.

Australia, however, has not experienced any growth in LNG investment over the same period. Australia's market share of Peer Countries' investment in midstream and downstream facilities including LNG liquefaction projects remains below 8% and has not shown any signs of recovery since the pandemic.

Figure 28 – Midstream gas & LNG processing CAPEX – Peer Countries and Australia's share, 2017-2024



Source: Wood Mackenzie

Investment across the natural gas and LNG value chain is recovering at a reasonably strong pace since the market lows observed between 2015 and 2020. But it is increasingly becoming clear that Australia is being left behind by its Peer Countries.

Exploration & Appraisal activity remains well below long term averages and **Australia attracts just 3% of total E&A investment dollars across the cohort.**

While upstream gas production investment does show signs of growth, this is focused on unconventionals and the backfilling of existing ullage, rather than growing overall production.

Australia has been unable to attract capital to invest in LNG liquefaction, despite Peer Countries almost doubling their annual investment in the sector since 2020 amidst a global demand surge.

Why is Australia diverging from its Peer Countries when it comes to investment in the natural gas, LNG and CCS sectors?

5. Factors influencing investment

Investment decisions in natural gas, LNG and CCS projects are complex and multifaceted, influenced by a wide array of factors that investors must carefully consider. These factors span geological, economic, political, and technological domains, each contributing to the overall risk-reward profile of potential investments.

Key factors that influence the level and location of investment in these sectors include geological factors (how good is the resource), economic factors (will the investment generate a sufficient return), political and regulatory factors (what are the risks to long term stability), technical factors (how prospective is the resource), environment, social and governance factors (will the investment be socially and environmentally acceptable) and company-specific factors (does the investment align with the investor's strategy).

The interplay between these factors creates a complex decision-making environment. Moreover, the increasing emphasis on environmental, social, and governance (ESG) considerations (outside of the United States) is reshaping investment criteria. Companies are now expected to demonstrate not only financial viability but also environmental stewardship and social responsibility in their projects.

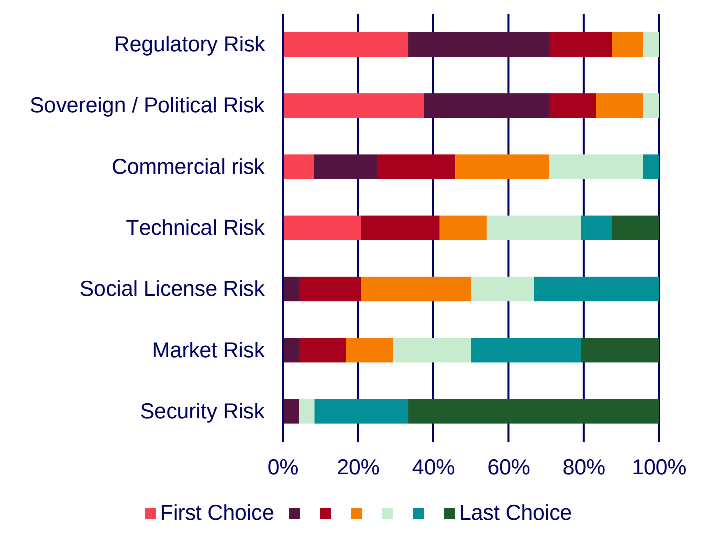
Considering this, an analysis of the major factors influencing investment decisions in Australia and Peer Countries has been carried out to better understand what may be driving Australia's loss of investment share across natural gas, LNG and CCS.

5.1. Defining the elements that drive investment decisions

The most important factors that investors consider when making investment and capital allocation decisions across the natural gas and LNG value chain include:

- Commercial and market risk
  - Commercial and fiscal terms
  - Fiscal stability
  - Market attractiveness
  - Cost of development
  - Security risk
- Technical risk
  - Resource potential
  - Prospectivity
- Political and regulatory risk
  - Regulatory stability
  - Regulatory burden
  - Approvals processes
  - Social license

A survey of Australian Energy Producers members ranked Regulatory and Sovereign / Political Risk as the most important factors considered when making investment decisions in Australia. Commercial and Technical Risk also ranked highly – countries need attractive, stable fiscal terms and strong prospectivity, but above all Investors are seeking regulatory stability and supportive policy to underpin capital allocation decisions.



5.1.1. Commercial and market

Commercial risk in the oil and gas industry refers to the potential for financial losses or underperformance due to market-related factors that affect the profitability of exploration, production, and distribution activities. Factors such as global economic conditions, technological advancements in alternative energy sources, and shifts in consumer preferences towards greener solutions further compound the commercial risk profile. Moreover, the long-term nature of many oil and gas projects, coupled with substantial upfront capital requirements, amplifies the potential consequences of misjudging market dynamics or failing to adapt to changing industry trends.

Commercial and fiscal terms

Fiscal terms in the context of natural gas, LNG and CCS investment refer to the financial and contractual arrangements between host governments and energy companies that govern the exploration, development, and production of hydrocarbon resources. These terms are crucial in determining the economic viability of projects and the distribution of risks and rewards between the parties involved.

The primary objective of fiscal terms is to strike a balance between attracting investment from energy companies while ensuring that the host country receives a fair share of the resource wealth. These terms typically encompass a range of financial mechanisms, including:

- **Royalties:** A percentage of production or revenue paid to the government as compensation for the right to extract resources. Royalties can be fixed or sliding scale based on production levels or commodity prices.

- **Production Sharing Contracts (PSCs):** Agreements where the government and the oil company share production after the recovery of costs. The split can vary based on production levels, profitability, or other factors.

- **Taxes:** Various forms of taxation, including corporate income tax, windfall profit tax, and export duties. These may be subject to special provisions or stabilisation clauses.

- **Bonuses:** One-time payments made at specific milestones, such as upon contract signing, discovery, or commencement of production.

- **State Participation:** The government's right to participate in the project, either through a carried interest or a paying interest.

- **Cost Recovery:** The mechanism by which companies recover their exploration and development costs before profit sharing begins.

- **Ring-fencing:** Provisions that determine whether costs and revenues from different projects can be consolidated for tax purposes.

The specific combination and structure of these elements can vary significantly between countries and even between different projects within the same country. Factors influencing the design of fiscal terms include the geological prospectivity of the area, the level of exploration and development risk, the country's political and economic stability, and global market conditions.

From an investor's perspective, the analysis of fiscal terms is critical in assessing the potential returns and risks of a project. Key metrics used in this evaluation include Fiscal Attractiveness and Fiscal Stability – how competitive a country or projects terms are for the investor, and how likely they are to stay that way over the long term.

The global trend in fiscal terms has been towards greater complexity and flexibility, with mechanisms designed to adapt to changing oil prices and production profiles. This includes the use of R-factors (ratio of cumulative revenue to cumulative costs) to adjust profit-sharing terms, and price-sensitive royalty rates.

Moreover, the increasing focus on ESG factors is influencing fiscal terms. Governments are incorporating provisions related to local content requirements, environmental protection, and community development into their fiscal frameworks.

Fiscal attractiveness

Fiscal attractiveness describes the overall appeal of a country's or region's fiscal regime to potential investors in the energy sector. It is a critical factor that influences companies' decisions on where to allocate their exploration and production capital. A fiscally attractive regime balances the government's desire to maximise revenue from its natural resources with the need to provide sufficient incentives for oil and gas companies to invest.

The fiscal attractiveness of an oil and gas investment opportunity is determined by a complex interplay of factors, including:

- **Government Take:** This is perhaps the most critical element, representing the total share of project value captured by the host government through various fiscal instruments such as royalties, taxes, and production sharing. A lower government take generally increases fiscal attractiveness, but this must be balanced against the government's need to maximise returns from its natural resources.

- **Progressivity:** How the fiscal system responds to changes in project profitability. A progressive system that allows investors to capture more upside in high-price scenarios while providing some protection in low-price environments can enhance attractiveness.

- **Cost Recovery Mechanisms:** The speed and extent to which companies can recover their investments affect project economics. Generous cost recovery provisions can improve fiscal attractiveness, especially for high-cost or high-risk projects.

- **Ring-fencing Provisions:** The ability to consolidate costs and revenues across different projects within a country can impact overall returns and thus fiscal attractiveness.

- **Fiscal Incentives:** Special provisions such as tax holidays, accelerated depreciation, or investment credits can enhance attractiveness, particularly for frontier or challenging areas.

- **State Participation:** While often seen as a reduction in attractiveness, well-structured state participation can align interests and potentially improve project economics through reduced taxes or fees.

- **Ease of Administration:** Simple, transparent fiscal systems are generally more attractive than complex ones, as they reduce compliance costs and uncertainties.

It is important to note that fiscal attractiveness is not solely determined by the generosity of terms. The overall investment climate, including factors such as political stability, rule of law, infrastructure quality, and ease of doing business, plays a significant role. Moreover, geological prospectivity is a fundamental consideration – even the most attractive fiscal terms cannot compensate for poor resource potential.

Fiscal stability

Oil and gas investors frequently state that stability and predictability in fiscal systems is a prerequisite for investment. Fiscal stability is a measure used to describe the predictability, consistency, and reliability of the fiscal regime governing hydrocarbon exploration and production activities within a given jurisdiction. Fiscal stability is a critical consideration in investment decision-making, risk assessment, and long-term project planning. It plays a pivotal role in determining the attractiveness of investment opportunities and the overall confidence in a country's oil and gas sector.

The importance of fiscal stability stems from the unique characteristics of oil and gas projects:

- **Long-term nature:** Exploration and production projects often span decades, requiring assurance that the economic basis for investment decisions will remain valid over time.

- **High upfront costs:** Significant capital expenditures are incurred before any revenue is generated, increasing vulnerability to changes in fiscal terms.

- **Price volatility:** The cyclical nature of oil and gas prices necessitates a stable fiscal framework that can accommodate market fluctuations.

- **Political sensitivity:** As natural resources are often viewed as national assets, there can be pressure to adjust fiscal terms, especially during periods of high commodity prices.

Key components of fiscal stability include:

- **Contractual Guarantees:** Stability clauses in PSCs or concession agreements that protect investors from unilateral changes to fiscal terms.

- **Legislative Framework:** A robust legal system that respects the sanctity of contracts and provides clear mechanisms for dispute resolution.

- **Transparent Processes:** Clear and consistent procedures for awarding licenses, approving development plans, and administering fiscal regimes.

- **Predictable Revisions:** When changes to fiscal terms are necessary, they are implemented through a transparent, consultative process with reasonable transition periods.

- **Grandfathering Provisions:** Protecting existing investments from changes in fiscal terms that apply to new projects.

The absence of fiscal stability can lead to investors increasing their risk premium to compensate for perceived fiscal instability, and preference short-term projects with fast payback periods over long-term developments that could maximise resource recovery.

Market attractiveness

Outside of fiscal, commercial, technical and regulatory risks, assessing the overall attractiveness of a market for investment in natural gas, LNG and CCS projects needs to consider other factors that can affect long-term stability and returns:

- **Location** is an important consideration for LNG export projects – shorter shipping routes equate to lower overall landed LNG prices, and strategic bottlenecks (such as the Suez or Panama Canals) can put trade at risk.

- **Existing infrastructure** may advantage a particular market over one without, as it helps to lower capital costs and is often linked to other benefits such as a skilled workforce with relevant sector expertise.

- **Long-standing trade relationships** with major LNG importers provide a solid foundation for ongoing business and the potential for long term contracts to underpin investment.

- **A strong economy, robust institutions and a transparent and fair regulatory framework** is also beneficial for investors considering long term investment across different markets.

Cost of development

The cost of development refers to the capital expenditures required to bring a discovered hydrocarbon resource into production. This phase follows exploration and appraisal, and precedes the production stage in the lifecycle of an oil or gas field. Understanding and accurately estimating development costs is crucial for investors, operators, and stakeholders to assess the economic viability of a project and make informed investment decisions.

The cost of development goes beyond just its impact on investment returns. When analysing cost of development, investors need to consider:

- **Affordability:** a project may have strong economics and high forecast returns, but the total capital exposure needs to be considered in the context of a company's ability to finance this expenditure in a capital-constrained business.

- **Timing:** natural gas, LNG and CCS projects are highly capital intensive, and this capital outlay is mostly incurred before revenue is generated from production.

- **Risk:** capital cost risk is particularly significant in the upstream sector due to the complex, long-term nature of projects and the multitude of variables involved. Factors contributing to capital cost risk include geological uncertainties, technological challenges, regulatory changes, market fluctuations, and geopolitical instabilities. The magnitude of this risk can be amplified by project scale, location (especially in frontier or deep-water environments), and the implementation of novel technologies.

Security

Physical safety and security is a consideration when investing in natural gas, LNG or CCS projects. Regions or countries with highly prospective resources and favourable fiscal terms may be attractive for investment, but if safety and security of company employees, contractors or the general public cannot be assured, investment may be deterred. Similarly, as ESG has become more front of mind for investors, host Governments must ensure that strong and transparent policies are in place to address the risks associated with modern slavery, environmental damage, graft or facilitation and fair labour practices.

5.1.2. Technical

The main driver in any upstream investment decision is the geological prospectivity: 'how compelling are the rocks'? The hypothesis is that those countries with the highest prospectivity rating are most likely to attract the most investment.

Resource potential

Resource potential refers to the estimated quantity of hydrocarbons that may be recoverable from a given area, reservoir or country. This concept is fundamental to the upstream sector, as it forms the basis for investment decisions, project planning, and valuation of assets. Resource potential is typically classified according to the Petroleum Resources Management System (PRMS), which provides a framework for categorising resources based on their level of certainty and commercial viability.

Countries with higher resource potential offer greater opportunities for significant returns. The potential for larger discoveries and more extensive reserves translates to higher production volumes and longer field life, which can substantially improve project economics and long-term profitability. Larger resource bases also allow for economies of scale in development and production. This can lead to lower per-unit costs, as fixed costs are spread over a larger resource base, enhancing overall project economics and competitiveness.

Prospectivity

Prospectivity considers non-financial or commercial attributes that make a field, play or country more or less attractive than competitors. This includes the amount and type of resource available, the potential to grow or replace this resource over time, geological attractiveness, access to markets and other comparative advantages. Prospectivity is defined by a number of factors that can be compared across regions, countries and plays:

- **Total volumes discovered (all time)** Commercial and technical reserves discovered.

- **Average discovery size** Total volumes discovered in the preceding ten-year cohort and the current year thus far divided by the number of successful exploration wells drilled.

- **Recent discoveries** Commercial and technical reserves discovered in the preceding ten-year cohort and the current year thus far.

- **Exploration well success** Number of exploration wells that resulted in hydrocarbon discovery as a percentage of total exploration wells drilled in the preceding ten-year cohort and the current year thus far.

- **Yet to find volumes (YTF)** Estimated volumes yet to find based on creaming curves.

- **Percentage of oil in recoverable reserves (preceding twenty-year cohort and the current year thus far)** Total liquids commercial and technical reserves discovered as a percentage of total commercial and technical reserves discovered (liquids are oil, LPG, condensate and other liquids).

5.1.3. Political and regulatory

Regulatory stability

Regulatory stability is a critical factor in the decision-making process for natural gas, LNG and CCS investments. A stable regulatory environment is crucial for assessing project viability, managing risks, and ensuring long-term value creation. Regulatory stability refers to the consistency, predictability, and transparency of laws, regulations, and policies governing the industry in a given jurisdiction. It encompasses various aspects, including:

- Licensing and permitting processes
- Environmental regulations
- Health and safety standards
- Local content requirements
- Dispute resolution mechanisms

The importance of stability across these various elements is crucial to investor confidence in a jurisdiction:

- **Risk Mitigation:** A stable regulatory environment reduces political and legal risks associated with long-term investments. It allows companies to more accurately assess and manage risks, leading to more confident investment decisions.

- **Financial Planning and Forecasting:** Regulatory stability enables more accurate financial modeling and forecasting. Consistent fiscal terms and regulatory requirements allow for better estimation of costs, revenues, and project economics over the life of an asset.

- **Project Economics:** Sudden changes in regulations can significantly impact project economics. Stability ensures that the economic assumptions made during the investment decision remain valid throughout the project lifecycle.

- **Capital Allocation:** In a global industry where capital is mobile, regulatory stability becomes a key differentiator for countries competing for investment. Stable regimes are more likely to attract and retain capital investment.

- **Operational Efficiency:** A stable regulatory environment allows companies to optimise their operations without the constant need to adapt to changing rules, leading to improved efficiency and cost-effectiveness.

- **Long-term Planning:** Energy projects often span decades. Regulatory stability is crucial for long-term planning, including decisions on technology deployment, infrastructure development, and workforce management.

- **Stakeholder Confidence:** Stability provides confidence to various stakeholders, including investors, lenders, partners, and local communities, enhancing the overall support for projects.

Regulatory burden

Stability of regulations is an important aspect of investment decision making; however, the overall regulatory burden is also important. Stable but restrictive or costly regulation may impact an investment more than somewhat less stable but less restrictive or costly regulation. Regulatory burden refers to the collective weight of rules, regulations, and compliance requirements imposed on energy companies by governmental and regulatory bodies.

Regulatory compliance often involves significant costs, both in terms of capital expenditure (e.g., equipment design) and operational expenses (e.g., monitoring, reporting). These costs directly impact project economics and can influence investment decisions. Additionally, extensive regulatory requirements can lead to prolonged approval processes and project delays, affecting the timing of first production and overall project returns.

Approvals processes

Regulatory, legal and environmental approval processes serve as critical gatekeepers to natural gas, LNG and CCS developments, significantly influencing a project's timeline, cost structure, and ultimate viability. Stringent regulatory requirements and environmental assessments can introduce substantial delays, increase capital expenditures, and even lead to project modifications or cancellations. Moreover, the complexity and duration of these approval processes can vary greatly between jurisdictions, directly impacting a project's risk profile and potential return on investment. In an era of heightened environmental awareness and evolving regulatory landscapes, projects with smoother approval pathways may offer a competitive advantage.

Social license

Social license to operate is an important factor for investors considering natural gas, LNG or CCS projects, as it directly impacts a project's long-term viability and profitability. This intangible yet crucial asset refers to the ongoing acceptance and approval of a project by local communities and other stakeholders. For investors, a strong social license can mitigate operational risks, reduce delays and associated costs, enhance reputation, and improve access to resources and talent. Conversely, a weak or absent social license can lead to project disruptions, legal challenges, regulatory hurdles, and even forced shutdowns, all of which can significantly erode investment value.

The importance of social license can vary considerably between countries, reflecting differences in cultural norms, political systems, economic conditions, and environmental priorities. In developed nations with robust regulatory frameworks and active civil societies, obtaining and maintaining social license often requires extensive stakeholder engagement, transparent operations, and demonstrable commitments to environmental stewardship and community development. In contrast, emerging economies may prioritise economic development and job creation, potentially leading to a different set of expectations for social license. However, it's crucial to note that even in countries where formal regulations may be less stringent, neglecting social license can still result in significant operational and reputational risks.

5.2. Australia's relative competitiveness

Australia's oil and gas sector presents a unique proposition for investors when compared to other countries, particularly in terms of fiscal terms and prospectivity. From a fiscal perspective, Australia offers a relatively stable and transparent regulatory environment, with a tax regime that includes a PRRT for offshore projects and various state-based royalty systems for onshore projects. While these terms are generally considered competitive, they may not be as attractive as those offered by some emerging oil and gas provinces seeking to incentivise exploration.

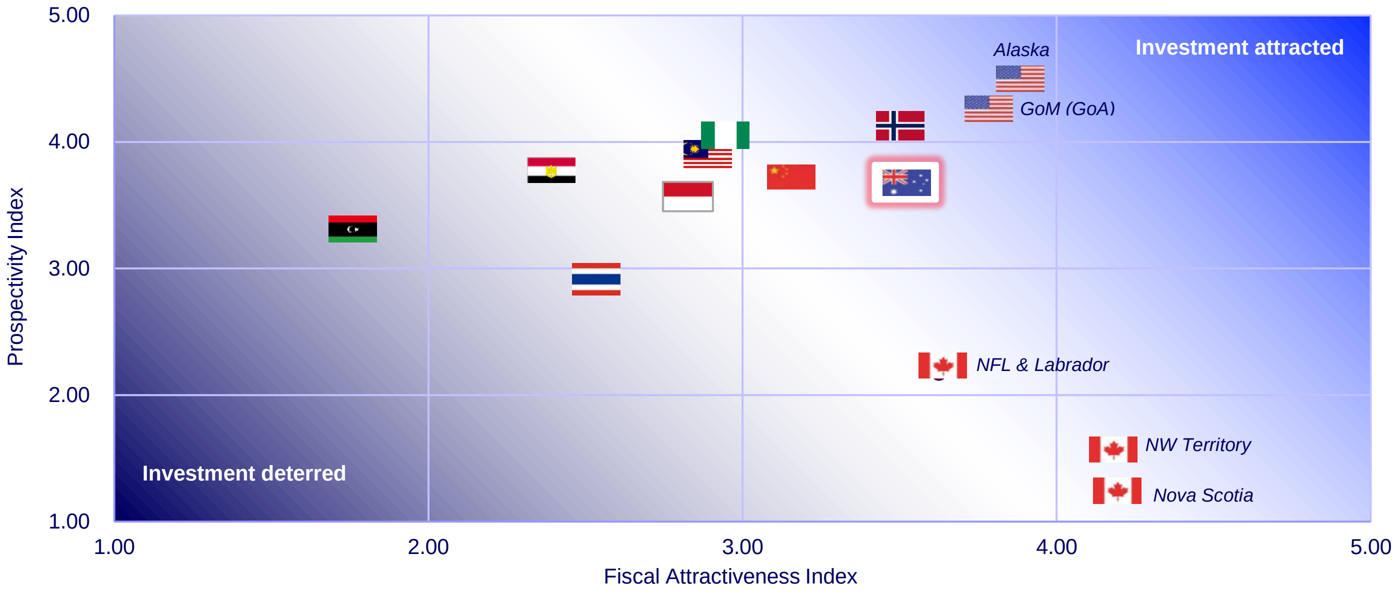
In terms of prospectivity, Australia boasts significant potential – the country's vast and largely underexplored acreage presents opportunities for new discoveries, especially in deep and ultra-deepwater plays. However, Australia faces challenges in terms of high operating costs, remote locations, and increasing environmental scrutiny, particularly for unconventional resources like coal seam gas. When compared to prolific regions such as the Middle East or North America's shale plays, Australia's fields generally have lower production rates and higher development costs. Nevertheless, the country's political stability, well-developed infrastructure, and proximity to growing Asian markets offer strategic advantages.

Overall, Australia's Fiscal Attractiveness is comparable to Norway and parts of Canada, though not as attractive as the United States. In terms of Prospectivity, Australia outperforms – on a par with Southeast Asia and parts of Africa and well ahead of Canada. The United States (Alaska / GoM (GoA)[1]) remains the most prospective jurisdiction amongst Peer Countries, and overall is possibly the most attractive destination for investment in natural gas, LNG and CCS projects. This is reflected in the growth trajectory of the US gas and LNG sector, with the United States competing with Qatar to be the world's largest supplier of LNG.

---

[1] *GoM (GoA) Gulf of Mexico (Gulf of America)*

Figure 29 – Relative competitiveness of Australia vs. Peer Countries – Fiscal Attractiveness vs Prospectivity[1]



1. Qatar not shown (data not available). Source: Wood Mackenzie

5.2.1. Commercial and market competitiveness

Commercial and fiscal terms

Australia's fiscal terms and commercial returns remain competitive with Peer Countries. Whilst fiscal terms are objectively stable, there have been negative changes over the last decade that has impacted Australia's fiscal stability ranking.

However, total government share is comparable to Peer Countries that do not invest via National Oil Companies (NOCs), and other metrics including front-loading and flexibility are generally competitive.

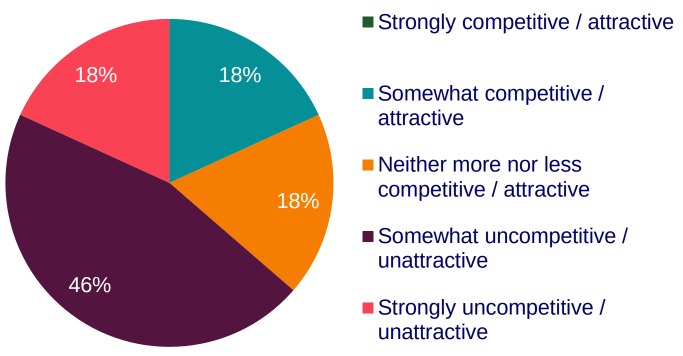
Fiscal attractiveness

Wood Mackenzie's fiscal attractiveness index describes how harsh or benign the fiscal terms for new licences currently are. It looks at the government's share of future cash flows from a range of hypothetical developments under various prices and current fiscal terms. This is supplemented with considerations of bonuses payable and the level of carried state equity. The hypothesis is that countries with the most favourable fiscal terms will have the highest fiscal attractiveness rating, and vice versa.

Using this methodology, Australia's fiscal attractiveness (3.5) is comparable to most peer countries, and favourable to those jurisdictions whose investment is dominated by state-owned NOCs whose index rankings are generally lower than 3.0.

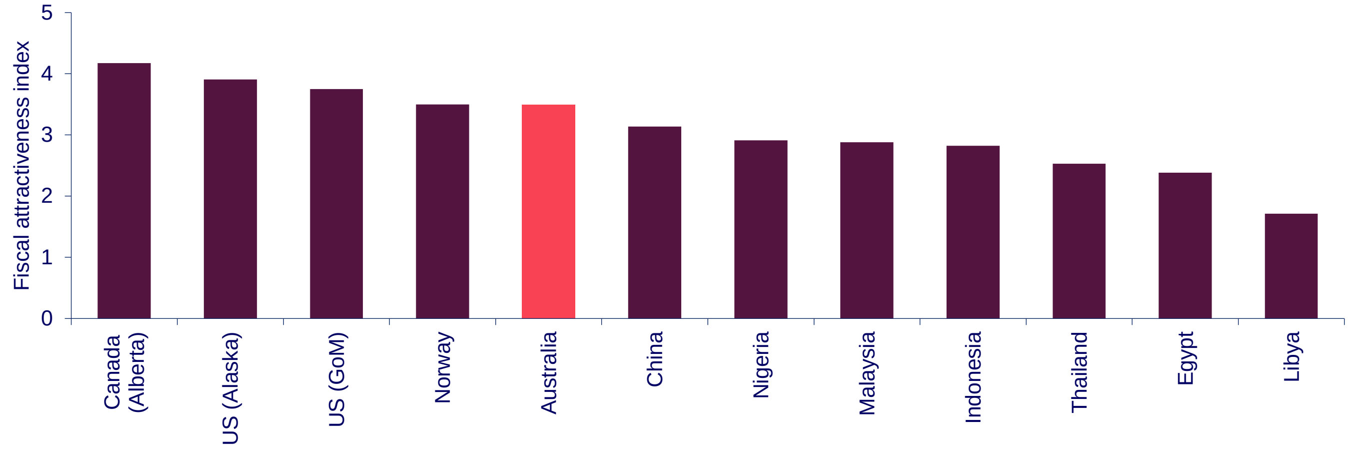
A survey of Australian Energy Producers members revealed that Australia's fiscal terms are considered relatively competitive with other countries. Of the respondents, 82% believed they were either Somewhat Competitive, Neither More or Less Competitive, or Somewhat Uncompetitive when compared to other countries that they invest in. This view is supported by the Fiscal Attractiveness data analysed by Wood Mackenzie.

Australia's fiscal terms - More or less competitive than Peer Countries?



Countries with state-owned NOCs typically invest and generate returns from their resources via these NOCs, which by default increases overall Government share of profits and lowers fiscal attractiveness for private investors. Australia's fiscal attractiveness is similar to the United States and parts of Canada, who do not have state-owned NOCs.

Figure 30 – Comparative fiscal attractiveness by country



Source: Wood Mackenzie

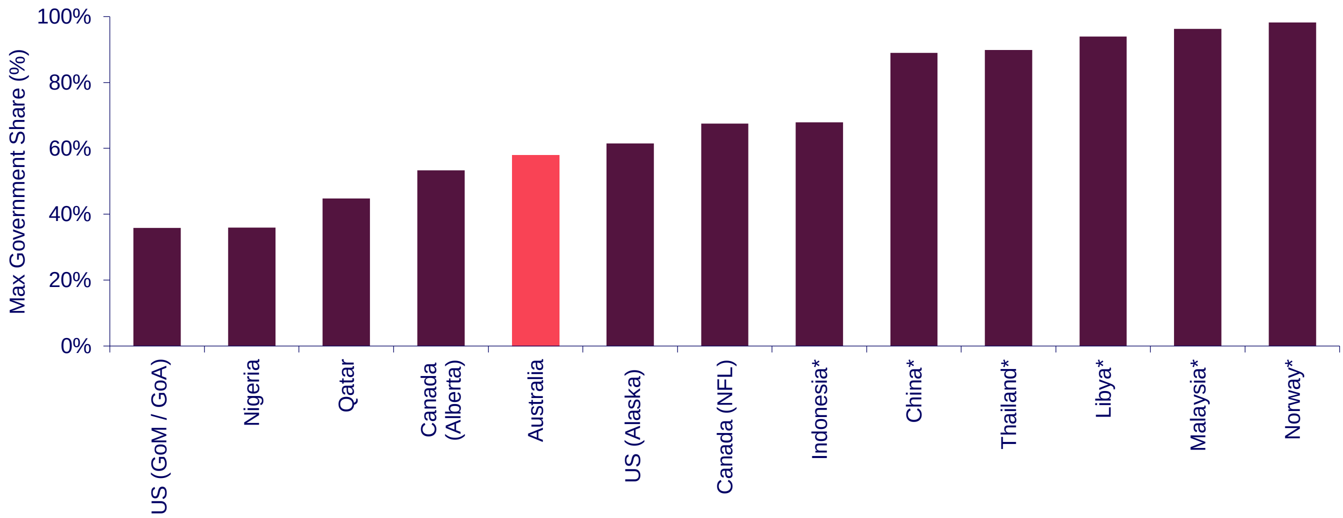
Government share

Countries compete for natural gas, LNG and CCS investments globally and Government share is a key factor in determining a country's attractiveness for investment. Companies compare fiscal terms across different countries when making investment decisions. As such, understanding government share is crucial for both energy companies and governments in structuring deals, managing expectations, and ensuring sustainable development of resources. The specific mechanisms and proportions vary widely between countries and even between different projects within the same country.

Onshore and offshore jurisdictions often have different fiscal terms, driven by the differing nature of the plays, their risks and government jurisdiction (State Government vs. Federal Government). Australia's onshore Maximum Government Share is competitive with peer countries, including the United States and Canada. Countries that typically invest in oil and gas development via state-owned NOCs have higher total Government shares, as any profits generated by the NOC are considered part of the total Government take of a project. This is evident in regions such as Southeast Asia, the Middle East and Africa.

Offshore, Australia's competitiveness in maximum government share is challenged. The United States has one of the lowest total government shares across the peer countries analysed, whilst state-controlled investment in Nigeria and Qatar also offer lower overall Government shares. This degrades Australia's fiscal competitiveness for offshore plays, which increasingly require large capital outlays and the involvement of larger oil and gas players with the depth of balance sheet to finance projects.

Figure 31 – Maximum Government share (average all play types) (2025)



** includes Government-owned NOC profit share and/or state equity. Source: Wood Mackenzie*

Fiscal stability

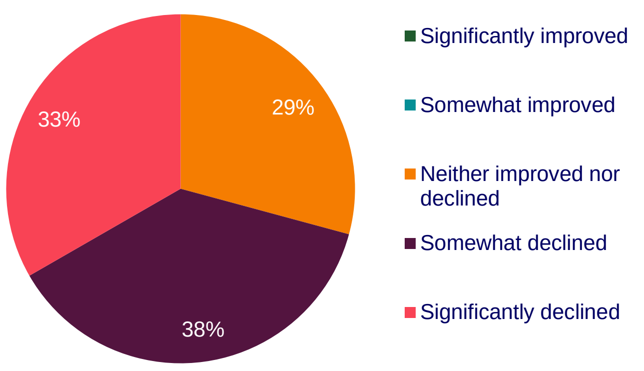
Australia's fiscal stability remains competitive with Peer Countries, however negative sentiment does persist in the industry, which has been subject to a number of negative changes in recent years. This has occurred over a timeframe that also included considerable regulatory intervention in the market, and so whilst Australia can be considered relatively fiscally stable, the instability in regulation means investor confidence has been eroded over the last 5 years compared to other jurisdictions.

Wood Mackenzie's Fiscal Stability Index is a tool used to assess and compare the stability of fiscal regimes in different countries or regions for the oil and gas industry. The index aims to measure how stable and predictable a country's fiscal regime is for oil and gas investments over time. The index considers various factors that contribute to fiscal stability, which include the frequency of changes to fiscal terms, the magnitude of changes when they occur the predictability of changes, transparency in the process of changing fiscal terms, adherence to contracts and agreements, political stability and its impact on fiscal policies and the historical track record of fiscal changes

Since 2002, Australia has made several significant changes to its fiscal terms for upstream oil and gas projects, which have had various impacts on investment returns. This included the expansion of the PRRT expansion in 2012 that extended PRRT to cover coal seam gas projects, the PRRT Review and Reforms between 2016 and 2019 and the introduction of a Decommissioning Cost Recovery levy in 2021.

A survey of Australian Energy Producers members shows that investors have a negative opinion of Australia's fiscal stability. Roughly a third believe Australia's fiscal terms haven't changed over the last 5 years, a third consider they have Somewhat Declined, and a further third believe they have Significantly Declined. Australia's fiscal terms have been relatively stable, but there have been changes in recent years (PRRT reform, offshore decommissioning levy) that have negatively impacted investors.

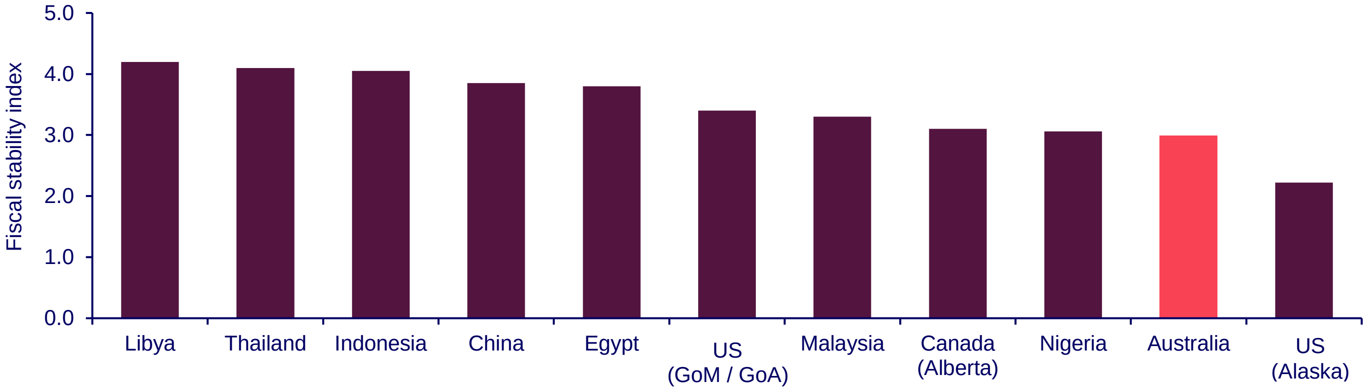
Australia's fiscal terms - how have they changed over the last 5 years?



Some changes have had positive impacts for investors such as the Offshore Petroleum Exploration Incentive introduced in 2004 that allowed immediate deductibility of certain exploration expenses, improving cash flow during the early stage of projects.

Whilst the number of changes to Australia's fiscal terms are higher than some Peer Countries, it remains relatively competitive overall. Australia's Fiscal Stability index rating (3.0) is similar to peers in Southeast Asia (Malaysia, 3.3), the United States (US GoM (GoA), 3.4), parts of Canada (Alberta, 3.1) and Africa (Nigeria, 3.1).

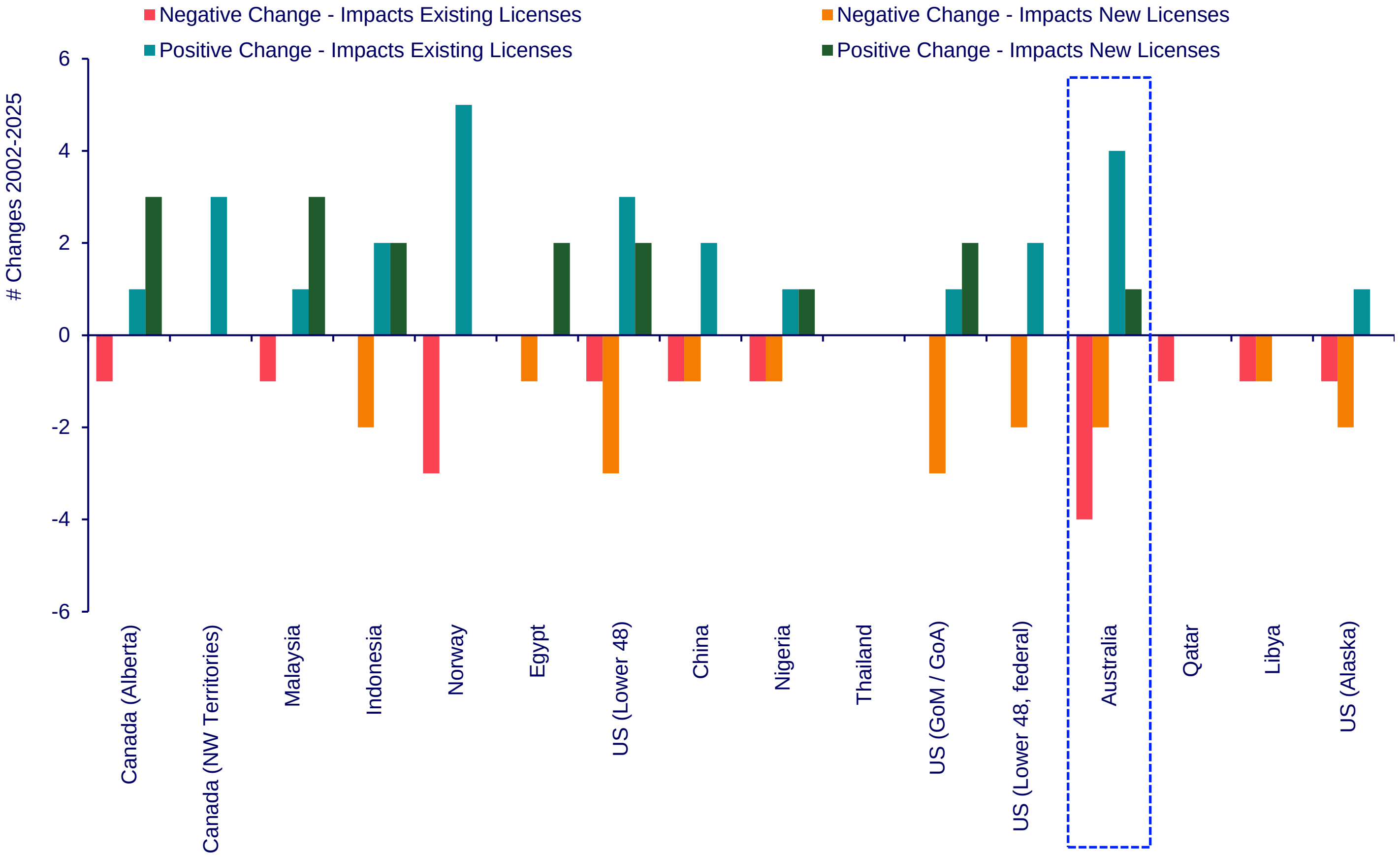
Figure 32 – Fiscal Stability Index by country



Source: Wood Mackenzie

The somewhat negative sentiment directed at Australia's Fiscal Stability is understandable, given the number of negative changes from investors' perspective, but it remains in line with most other comparable jurisdictions. Australia also has a higher proportion of retroactive changes that apply to existing licenses in addition to future licenses, which is reflective of Australia's comparatively lower contractual protections than Peer Countries. Contractual protections include stabilisation clauses in fiscal terms, dispute resolution methods, and Foreign Investment Review frameworks. Australia typically relies on its overall political and economic stability and does not include specific stabilisation clauses in contracts. It also important to distinguish between Fiscal Stability and Regulatory Stability – the former relates only to changes in fiscal terms (tax, royalties, shared equity etc.) and does not consider changes in other regulations, price controls, environmental conditions or restrictions.

Figure 33 – Number of fiscal term changes by impact – 2002 to 2025



Source: Wood Mackenzie

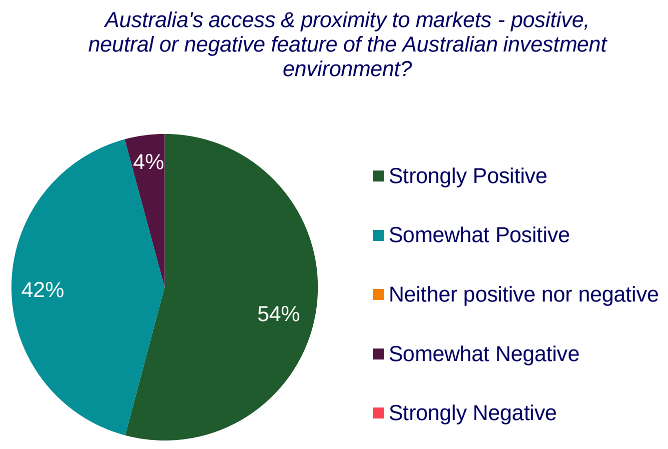
Market attractiveness

Australia is significantly advantaged in its location – proximate to large centres of energy demand in Asia. Australian LNG is shipped into Asia at half the cost of the United States and Qatar, and less than a third of the cost of African producers.

Australia is positioned competitively across the international export market as a key supplier to the Japanese LNG market. Australia's shipments typically arrive in Japan within 13 days for only US$0.84/mmBtu[2], but the price and time can vary slightly depending on the export terminal location within Australia. This is only slightly cheaper than those located in SE Asia who have a geographic advantage over the Australian market in terms of cost and time. Indonesia, Malaysia and Thailand all take between 8-9 days to arrive in Japan with Malaysia positioned as the cheapest exports at US$0.61/mmBtu.

The further away we travel from Asia the more costly and logically challenging the shipping journey is. For shipments departing the U.S, there are three main routes a ship can take – the Cape of Good Hope, Suez Canal or the Panama Canal. The Panama Canal is the most favourable route for LNG

A survey of Australian Energy Producers members shows that investors consider Australia's access and proximity to key markets a strong competitive advantage over other countries. Almost all respondents believe Australia's access and proximity to markets is a Strongly Positive or Somewhat Positive feature of Australia's investment environment.



[2] *Costs are based on long-term charter rates on currently available routes for the 174,000m^3 Mem (SSGI) ship. We assume an average fleet speed of 16 knots for all vessels and a newbuild cost assumption of US$260m for a 174,000m^3 capacity LNG carrier.*

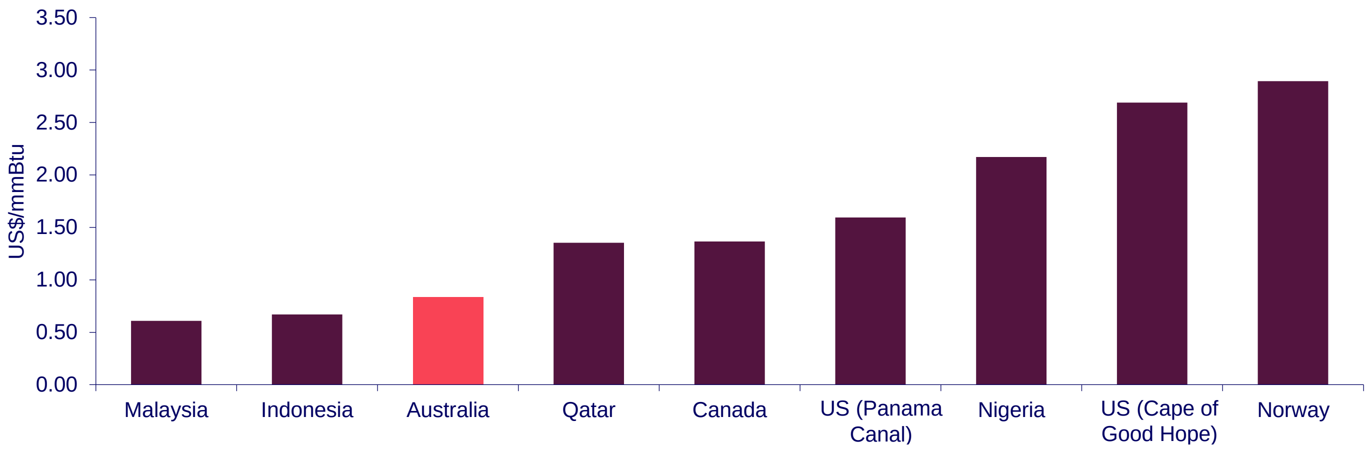
companies as it reduces the sailing time from the US Gulf Coast to Japan to about 20 days (compared to 42 days via the Cape). This results in lower shipping costs overall, as the savings in fuel, days and charter costs outweigh the tolls charged to traverse the Panama Canal.

However, in recent years the Panama Canal has experienced challenges, with severe droughts (2023-2024) leading to restrictions on daily vessel transits and draft limits, reducing capacity and increasing delays. Congestion and availability of transit slots can lead to higher toll payments or the requirement to switch cargoes to an alternative voyage route.

The Cape of Good Hope is the most costly and time-consuming route for US cargoes to reach Asia, taking 42 days. Whilst the cost is higher, there are periods where charter rates can fall, and many shippers may consider the certainty and visibility of delivery schedules worth the extra cost. The Cape of Good Hope route also provides greater destination flexibility for those with portfolio optionality.

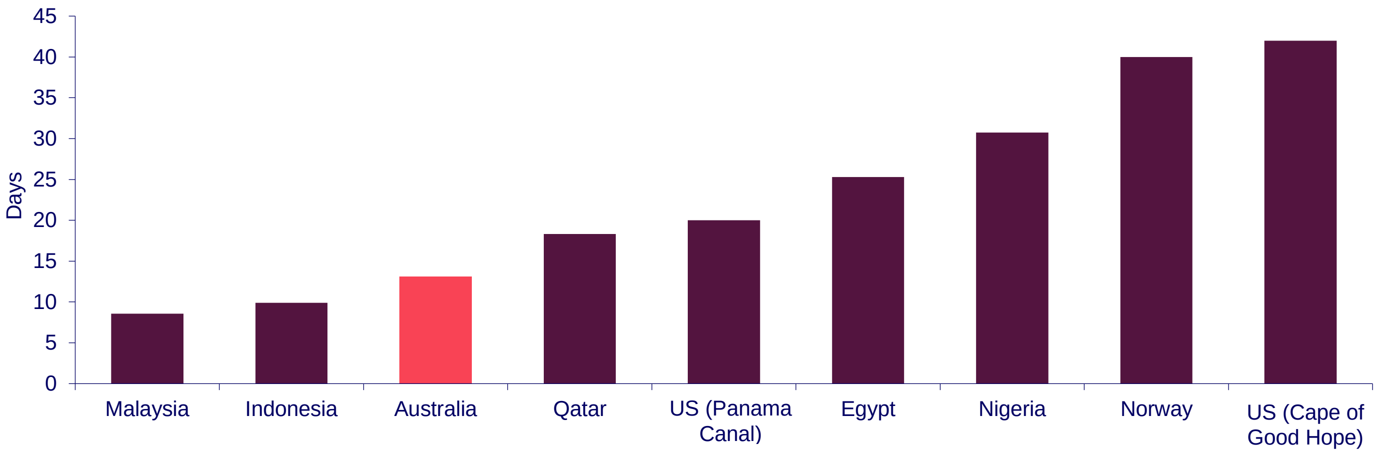
The Suez Canal is underutilised as a result of the Red Sea region having experienced increased piracy, conflict and Houthi-related attacks on vessels, increasing risk. This route is rarely used for shipments from the US to Japan (which would take 32 days), but Egypt relies on this passage for its transport to Asia (25 days). Norway also utilises this path as its main route, but its relatively high distance from Asian demand centres means it has the highest cost of LNG shipment – on average ex-Norway LNG cargoes take 40 days to arrive in Asia. Norway can also utilise the Northern Sea Route, which is faster and cheaper, but it is only used during summer months and with the Russia/Ukraine conflict, risk has increased and sanctions make it difficult to utilise Russian-operated vessels.

Figure 34 – Average shipping costs by export country to Japan



Note: Ship type modelled for shipping costs is a 174,000m^3 Mem (SSGI). Source: Wood Mackenzie

Figure 35 – Average days to complete voyage to Japan



Source: Wood Mackenzie

Cost of development

Upstream

Australia's Unit Development Cost (UDC) – defined by total upstream CAPEX spend per GJ of gas produced, is significantly higher than Peer Countries. This is partly a reflection of Australia's high share of unconventional upstream gas production – particularly for the CSG-to-LNG projects, as well as a high cost of labour, materials, equipment and infrastructure.

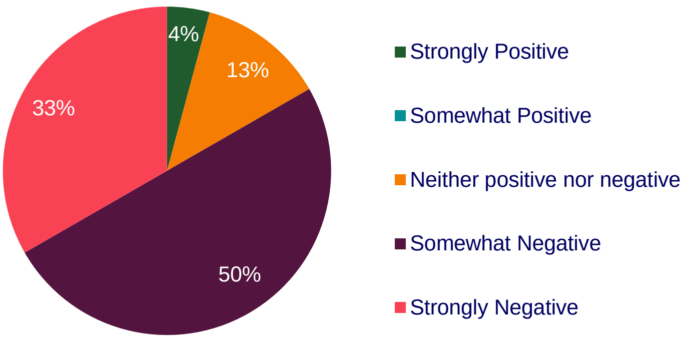
Australia's upstream UDC peaked in the mid-2010s at the peak of the East Coast's CSG-to-LNG developments. Multiple large and complex integrated projects combined with broader macroeconomic factors to drive up project costs and raise average upstream UDC above US$7 / GJ (Real, 2025).

As investment dropped as a result of lower commodity prices during 2015, and the COVID-19 pandemic in 2020, average UDC dropped below US$1.20 / GJ (Real, 2025). This still remained above all Peer Countries' average UDC except China.

Supply chain constraints, macroeconomic factors including high inflation and rising wages have combined to again lift Australia's average upstream UDC over the last 5 years, and it continues to remain above Peer Countries' averages.

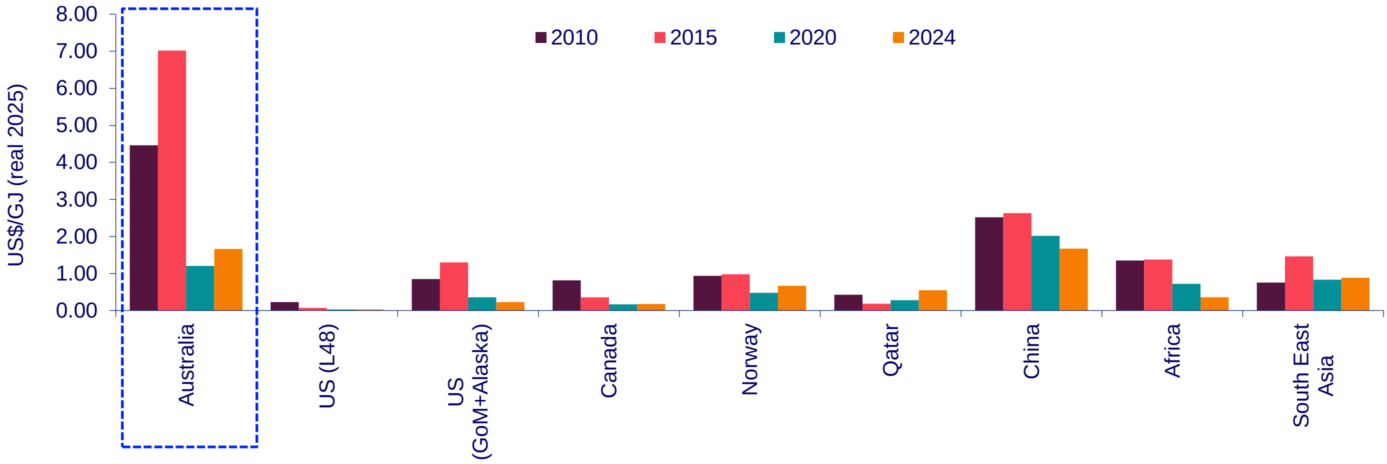
A survey of Australian Energy Producers members shows that investors consider Australia's cost of development is a significant comparative disadvantage when investing in natural gas or LNG projects. Over 80% of respondents consider Australia's cost of development to be a Strongly Negative or Somewhat Negative feature of Australia's investment environment.

Cost of development - positive, neutral or negative feature of the Australian investment environment?



It should be noted that UDC only reflects unit CAPEX spend per GJ of gas, and is not the Long Run Marginal Cost of production or the total cost to produce a GJ of gas.

Figure 36 – Ave. upstream gas production UDC – Peer Countries



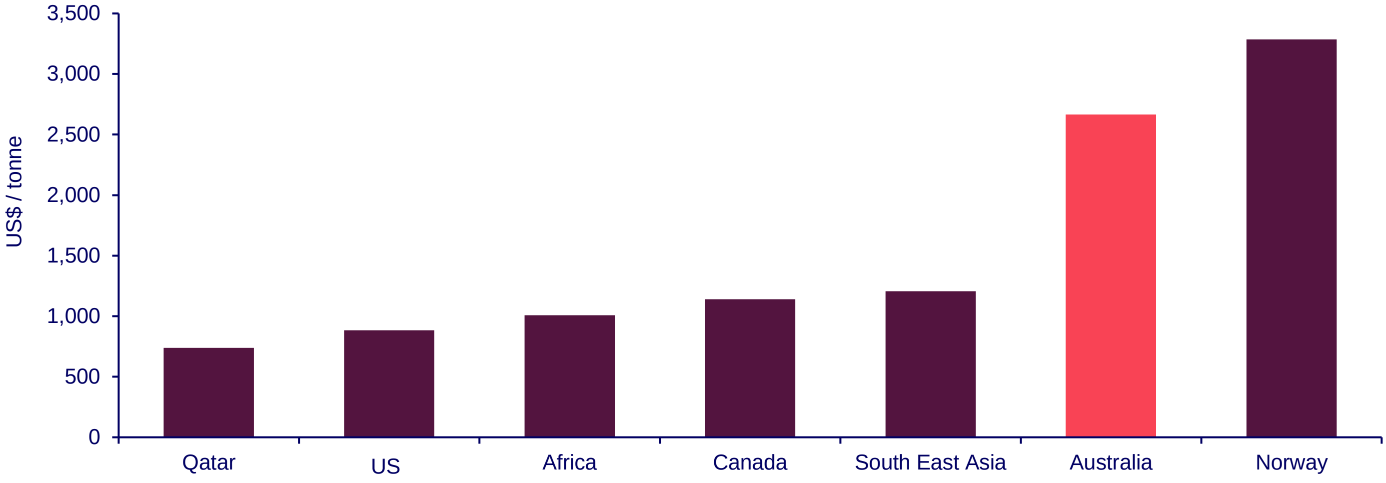
Source: Wood Mackenzie

Downstream (LNG)

The average capital cost for Australian LNG projects has ranged between US$2,000 and $3,500 per tonne of annual capacity, which is substantially higher than many Peer Countries. This elevated cost structure can be attributed to several factors, including Australia's remote project locations, high labor costs, stringent regulatory requirements, and the need for extensive infrastructure development in greenfield sites. These factors have contributed to Australia's position as one of the most expensive countries for LNG development on a per-tonne basis.

In contrast, other major LNG-producing countries have demonstrated lower capital costs per tonne of liquefaction capacity. For instance, projects in the United States have typically ranged from US$600 to US$900 per tonne, benefiting from existing infrastructure and a more developed domestic gas market. Qatar, another leading LNG exporter, has achieved costs as low as US$500 to US$1,000 per tonne, leveraging its vast reserves and established facilities. Even emerging LNG producers like Mozambique have projected costs in the range of US$1,000 to US$1,500 per tonne. This cost disparity has raised concerns about the long-term competitiveness of Australian LNG projects, particularly as global competition intensifies and buyers become increasingly price-sensitive.

Figure 37 – Average Peer Country plant CAPEX per tonne of LNG liquefaction capacity



Source: Wood Mackenzie

Wage costs

Australia's labour market is characterised by notably high wage rates compared to many other developed nations. This wage premium is attributed to a combination of factors, including a robust minimum wage system, strong labour unions, and a skills shortage in certain sectors.

According to OECD data, Australia consistently ranks among the top countries for average annual wages, often surpassing nations like the United States, Canada, and many European countries. While these high labour costs contribute to a high standard of living for Australian workers, they also present challenges for businesses, particularly in labour-intensive industries, affecting international competitiveness.

In the natural gas and LNG sectors, industry consistently reports some of the highest average salaries worldwide, surpassing those in other major gas-producing nations such as the United States, Qatar, and Russia. This wage premium is driven by several factors, including the remote locations of many Australian gas projects. According to industry reports, labour costs can account for up to 30-40% of total project costs in Australian LNG developments, compared to approximately 20-25% in other countries. This disparity has led to concerns about the long-term competitiveness of Australian gas exports, particularly as new low-cost producers enter the global market.

A survey of Australian Energy Producers members revealed that investors strongly consider Australia's labour costs and industrial relations system an investment deterrence. Over 95% of respondents consider Australia's labour costs and industrial relations system to be a Strongly Negative or Somewhat Negative feature of Australia's investment environment.

Labour costs & industrial relations - positive, neutral or negative feature of the Australian investment environment?

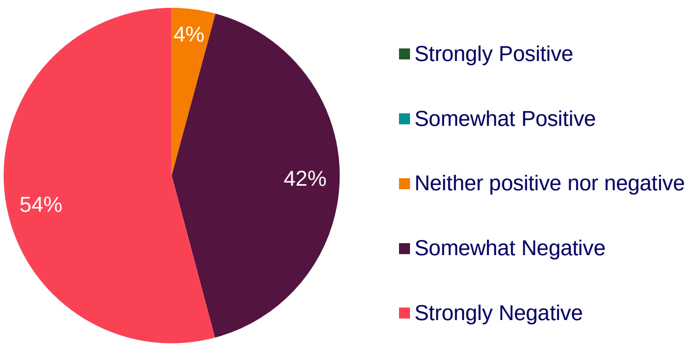
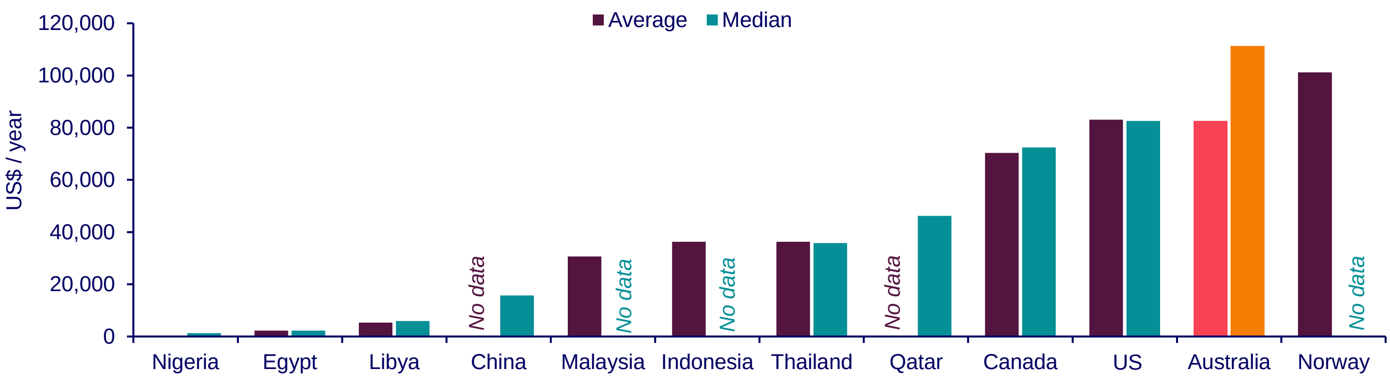


Figure 38 – Average & median annual wage – gas sector workers, by country (US$ / year)



Source: National Government wage data (various), Wood Mackenzie analysis.

Security

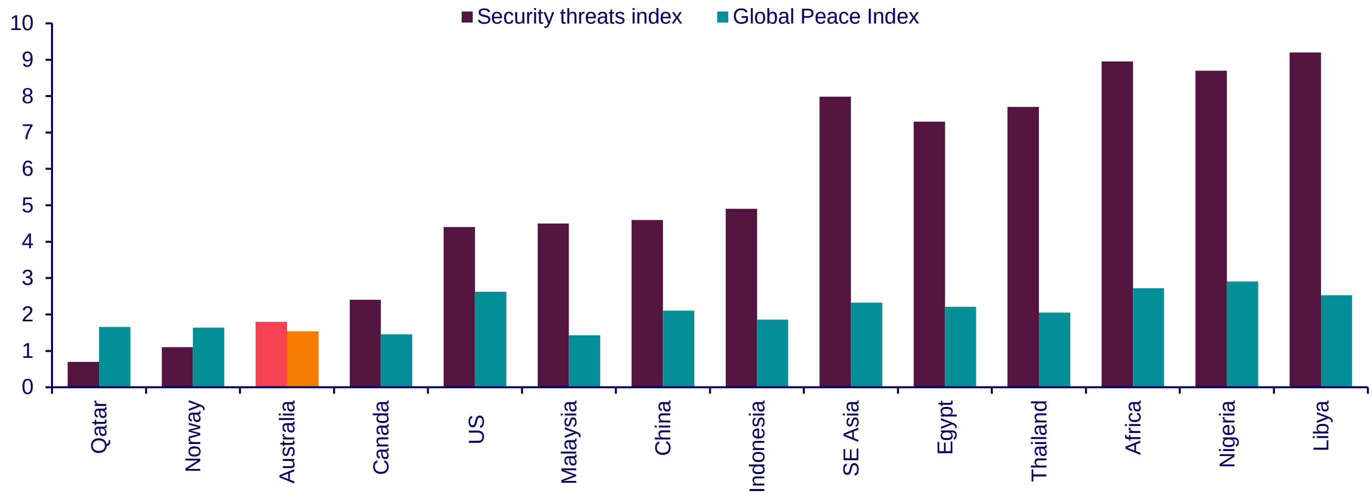
Security in Australia is among the best in the world – prosperous, politically stable and comparatively safe.

The Global Peace Index (GPI) presents trends in peace across three domains – the level of Societal Safety and Security, the extent of Ongoing Domestic and International Conflict and the degree of Militarisation. The lower the value of the index, the more peaceful the state.

The security threats index considers the security threats to a state, such as terrorism, military conflict, political stability and the level of serious crime. The higher the value of the index, the greater the security threats that exist in that state.

On both measures, Australia ranks in the top 20 countries globally and outperforms all Peer Countries, with the exception of Qatar (lower security threats index) and Norway (lower across both indicators).

Figure 39 – Security threat and Global Peace indices by country



Source: Global Peace Index, Security Threats Index, Wood Mackenzie analysis

5.2.2. Technical competitiveness

Resource

Australia's technical prospectivity remains among the highest across Peer Countries – large discovered volumes and remaining 2P reserves in areas served by existing infrastructure make Australia's resources attractive to investment from a technical perspective.

Australia is home to large reserves of natural gas across onshore, offshore, conventional and unconventional fields. Compared to peer countries Australia contains 8% of total remaining 2P reserves, which is equivalent to the 2P reserves of China and more than those of Norway. These reserves have remained relatively constant at around 125 tcf since 1990, despite total production of 80 tcf over the same period, suggesting strong reserve replacement rates to date.

Australia's 2C resources are less robust – just 88 tcf and 3% of total peer countries resources, which is dominated by Qatar with current 2C resource of 1,600 tcf in the prolific North Dome field offshore. This resource has allowed Qatar to invest in significant LNG capacity and vie with the United States for the title of largest LNG exporter by volume in the world.

A survey of Australian Energy Producers members underlined Australia's competitive resource potential – over 90% of respondents consider Australia's natural gas resources and reserves to be a Strongly Positive or Somewhat Positive feature of Australia's investment environment.

Natural gas resources & reserves - positive, neutral or negative feature of Australia's investment environment?

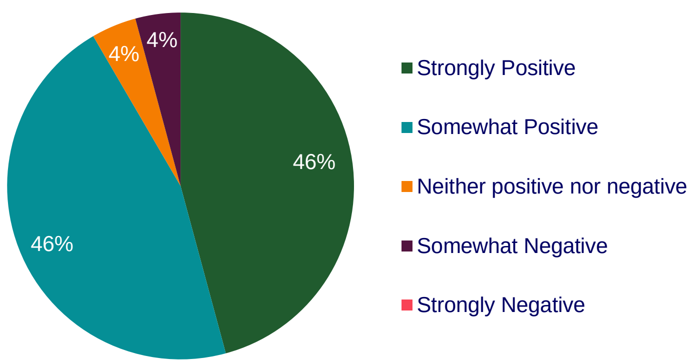
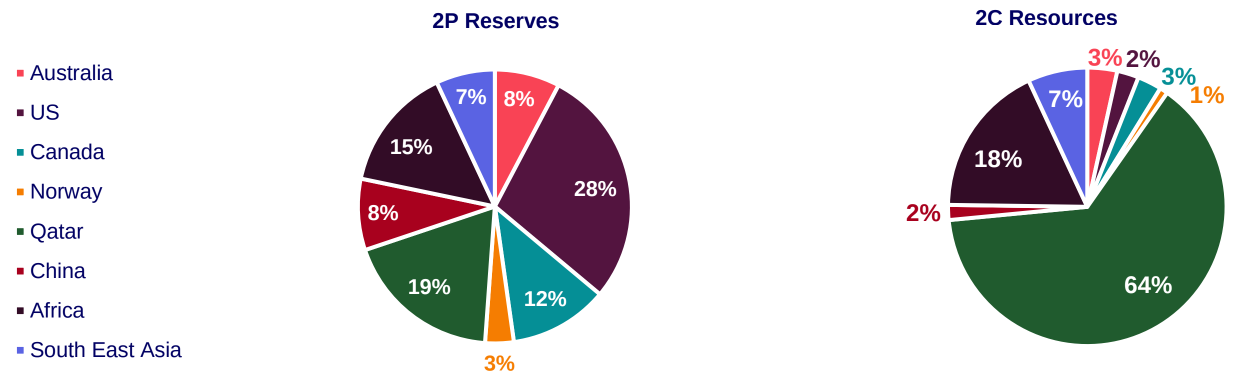


Figure 40 – 2P gas reserves and 2C gas resources by country (as of end 2024)



Source: Wood Mackenzie

Prospectivity

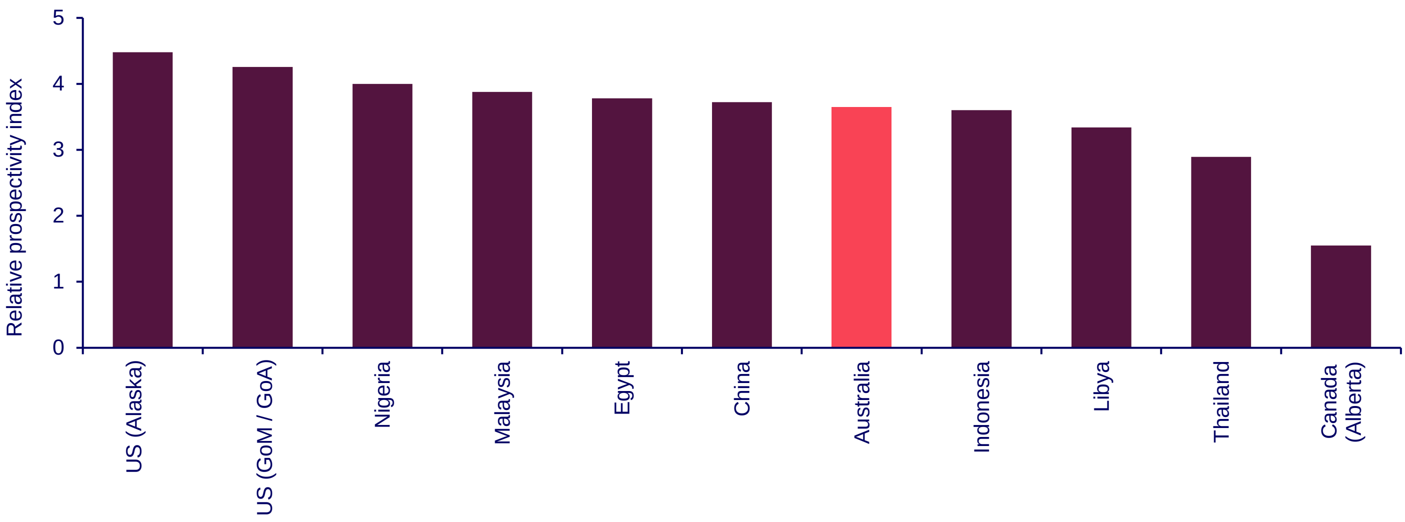
Overall, Australia's geological prospectivity comparable to that of other countries, though it is negatively affected by Australia's lack of oil resources and the overall lower volume of total discovered resource in recent years. Australian exploration performance is highly competitive – high well success rates (>35%) and large average discovery volumes (>200mmboe) are comparable to prolific basins in the United States and Africa.

Wood Mackenzie's relative prospectivity index compares countries, locations and water depths (for offshore plays) on the basis of recent exploration history (reserves discovered, success rates, etc) and yet to find (YTF) resource estimates.

Overall, Australia's geological prospectivity (3.6) is comparable to that of other countries, though it is negatively affected by Australia's lack of oil resources and the overall lower volume of total discovered resource in recent years. The United States, driven by the growth in shale oil and gas production, is the most prospective country of those analysed (4.3 to 4.5), outperforming Australia in total discovered volume, yet-to-find resource and discovered oil.

Australia's relative strength in geological prospectivity is generated by relatively successful exploration programs that over the last decade have resulted in sizeable finds rivaling those of Nigeria.

Figure 41 – Comparative geological prospectivity by country



Source: Wood Mackenzie

5.2.3. Political and regulatory competitiveness

Australia's natural gas and LNG industries operate under a regulatory framework that is often considered more stringent and complex than those of many competing nations. This heightened regulatory burden has significant implications for project development, operational costs, and international competitiveness. For a professional audience, it's crucial to understand the nuances of this regulatory landscape and its comparative impact.

Regulatory stability

Australia, and specifically the East Coast Gas Market (ECGM), has been subject to ongoing state and federal government intervention since 2012 when various moratoria on onshore exploration and drilling were introduced in New South Wales, Victoria and South Australia. Intervention has increased over time, with various regulatory safeguards and voluntary mechanisms announced since the start-up of the Queensland LNG export projects linked the ECGM to the global LNG market for the first time. This intervention was in response to the perceived risks that the domestic gas market could fall short or suffer elevated gas prices during peak periods.

There have been more than 25 different interventions in the Australian oil and gas sector by Federal and State Governments since 2012. Major changes included:

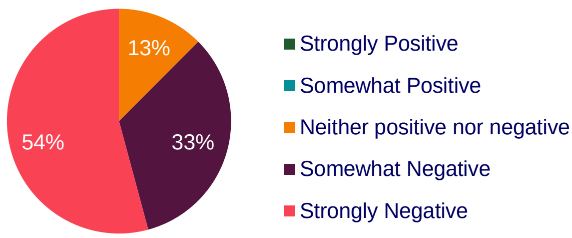
- Moratoria on onshore exploration and drilling introduced in New South Wales, Victoria and South Australia.
- Establishment of NOPSEMA (National Offshore Petroleum Safety and Environmental Management Authority).
- Establishing and tightening the Australian Domestic Gas Security Mechanism (ADGSM).
- Cancellation of annual offshore E&A acreage releases.
- Reforms to the Petroleum Resource Rent Tax (PRRT).
- Ongoing reforms to the Safeguard Mechanism that limits greenhouse gas emissions from major emitting facilities and projects.
- Introduction of an offshore decommissioning liability levy.
- Introduction of net zero requirements for major projects.
- Moratoria on hydraulic fracturing, and subsequent lifting two years later (Northern Territory).
- Establishing and revising the Heads of Agreement between the Australian Government and East Coast Liquified Natural Gas Exporters.
- Establishing and implementing the Gas Price Cap and the Mandatory Gas Code of Conduct.
- Releasing the Future Gas Strategy.

A survey of Australian Energy Producers members revealed that investors believe Australia's political and regulatory risk has deteriorated the last 5 years. Over 95% of respondents consider Australia's political, sovereign and regulatory risks have Significantly or Somewhat Declined over the last 5 years (that is, risk has worsened).

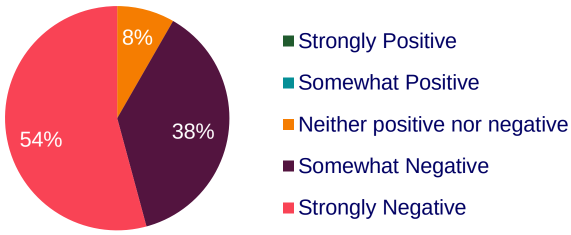
Additionally, and possibly most importantly for Australia's international competitiveness, 100% of respondents with investments outside of Australia consider Australia's regulatory risk to be Strongly or Somewhat Uncompetitive / Attractive compared to other countries they invest in.

Investors also believe Australia has significant problems with environmental regulation, timely permitting and approvals processes and high levels of political uncertainty.

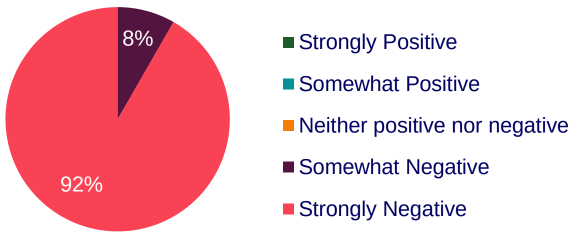
Energy and climate policies, including climate targets - positive, neutral or negative feature of Australia's investment environment?



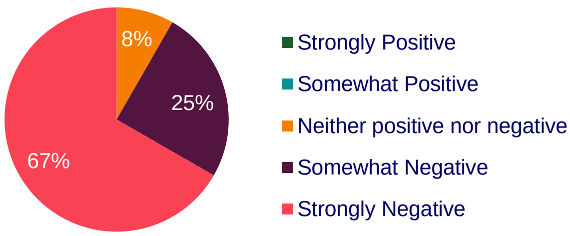
Environmental regulation - positive, neutral or negative feature of Australia's investment environment?



Timeliness of permitting and approvals processes - positive, neutral or negative feature of Australia's investment environment?



Regulatory certainty - positive, neutral or negative feature of Australia's investment environment?



Regulatory burden

Australia's federal system creates a complex regulatory environment where projects must navigate both Commonwealth and State/Territory regulations. This dual-layer approach often leads to:

- Overlapping jurisdictions
- Potentially conflicting requirements
- Extended approval timelines
- Increased compliance costs

In contrast, countries such as Qatar or Malaysia benefit from more centralised decision-making processes, potentially streamlining project approvals and reducing regulatory complexity.

The introduction of the ADGSM and various state-based domestic gas reservation policies add another layer of complexity not seen in many other LNG-exporting countries, including the potential for export restrictions to ensure domestic supply, and requirements to offer a portion of gas to the domestic market before export. These policies, while aimed at ensuring domestic energy security, can impact the flexibility and profitability of LNG export projects.

Investor views of Australia's current regulatory environment:

"Gas development is a long-term investment that requires positive sentiment and tangible action on approvals processes certainty. It provides a major economic input into the wealth of our nation. Australia needs to focus on diversity of energy security and decarbonisation and stop picking winners as favoured by current policy or it is in danger of losing its competitiveness relative to other countries."

"Stable and predictable policy is needed to ensure natural gas remains a reliable energy source – now and in the future."

"For the first time my company is assessing opportunities overseas as we see little improvement in future operating conditions in Australia."

"Lack of consistency, certainty and consultation from governments makes it challenging to understand the future investment environment."

"The cost to explore has increased significantly in recent years while the ability to explore has become extremely problematical while regulatory conditions are worsening."

"Urgent reform is required. It is so difficult to attract international parties to invest in Australia."

As the global LNG market becomes increasingly competitive, the impact of Australia's regulatory burden on project costs and timelines becomes a critical factor in maintaining the country's position as a leading LNG exporter. Balancing regulatory objectives with international competitiveness remains an ongoing challenge for both policymakers and industry participants.

Approvals processes

Australia's natural gas and LNG project approvals process is a complex, multi-layered system involving federal, state, and local government agencies. This process, while designed to ensure thorough assessment of environmental, social, and economic impacts, has become increasingly challenging for industry participants. The resulting delays are having significant impacts on project economic viability, potentially threatening Australia's position as a leading global LNG exporter.

The approvals process typically involves several key stages:

1. **Environmental Impact Assessment (EIA):** Required under the Environment Protection and Biodiversity Conservation (EPBC) Act 1999 for projects likely to have a significant impact on matters of national environmental significance.
2. **Native Title and Indigenous Land Use Agreements:** Negotiation with traditional landowners, often requiring extensive consultation and agreement-making.
3. **State-level Approvals:** Varying by jurisdiction, but often including environmental, planning, and resource development permits.
4. **Safety Case Approval:** Required by NOPSEMA for offshore projects, demonstrating how safety risks will be managed to As Low As Reasonably Practicable (ALARP).
5. **Production License:** Granted by the relevant state or federal authority, allowing for resource extraction.
6. **Export License:** Required for LNG export projects, granted by the federal government.

While well intentioned, Australia's project approvals processes create regulatory complexity. The multi-jurisdictional nature of approval creates a complex web of requirements, often with overlapping or conflicting demands. Evolving environmental and climate change policies can lead to changes in requirements during the approvals process. Increasing public scrutiny and activism require extensive stakeholder engagement, often leading to project modifications or delays. Stringent environmental requirements, particularly around greenhouse gas emissions, are becoming increasingly challenging to meet.

Projects are also increasingly facing legal challenges from environmental groups or other stakeholders, even after receiving initial approvals.

The protracted approvals process is having significant impacts on project economics – increased CAPEX, market window risks, financing challenges and opportunity costs add up to reduce the attractiveness of Australia natural gas and LNG projects compared to those in Peer Countries.

Several high-profile projects have faced significant challenges:

1. Woodside's Browse LNG: Multiple delays and redesigns have led to billions in sunk costs without reaching FID.
2. Santos' Narrabri Gas Project: Approval process lasted over a decade, significantly impacting project economics.
3. Santos' Barossa offshore gas project: Post-financial investment decision and post-offshore environmental approval, faced multiple Federal Court challenges that delayed drilling and pipelaying operations, adding up to A$500m to the CAPEX of the project.
4. Shell's Prelude FLNG: While eventually approved, the extended timeline contributed to cost overruns and delayed first gas.
5. Woodside's North West Shelf extension: after a six-year process of assessments and appeals, the decision to extend the use of existing NWS infrastructure was approved by the Western Australia state government. The same approval is required from the Federal Government, which has delayed their decision multiple times until mid-2025 at the earliest.

According to industry analyses, regulatory delays can significantly impact project economics in the resources sector. For mining projects, KPMG (2020) found that each year of delay could reduce a project's Net Present Value by 10-20%. While specific figures for LNG projects are not widely published, Wood Mackenzie analysis indicates that regulatory delays can substantially increase project costs and risks, potentially impacting project viability. Additionally, delays increase the risk of missing market windows in the highly cyclical natural gas and LNG market, with competitor projects proceeding ahead of Australian projects and capturing customer demand.

Environmental protection

Australia's environmental regulations are particularly stringent, especially in comparison to many other major LNG-producing nations. The Environment Protection and Biodiversity Conservation (EPBC) Act 1999 requires comprehensive environmental impact assessments for major projects. The National Greenhouse and Energy Reporting (NGER) scheme requires proponents of natural gas and LNG projects to comply with strict emissions reporting requirements. The Safeguard Mechanism imposes facility-level emissions baselines and offset requirements.

While countries like the United States have robust environmental regulations, they often vary significantly by state, potentially offering more flexibility. Qatar and Russia, major LNG competitors, generally have less stringent environmental requirements, particularly regarding greenhouse gas emissions.

Additionally, Australia's Native Title Act and related regulations necessitate extensive consultation and negotiation with Indigenous communities, including a requirement for Indigenous Land Use Agreements (ILUAs) in many cases. Under the Act, lengthy negotiation processes can significantly impact project timelines and open proponents to potential legal challenges based on inadequate consultation (see example over the page).

The Barossa gas field was discovered offshore Northern Territory in 2004. In 2014, the initial development concept for the field was proposed. Eleven years later (H125), the project has not yet commenced production. Granted approval by NOPSEMA, multiple Federal Court challenges overturned and then re-overturned this approval, delaying construction and adding A$500 million to the project's cost.

2014:

- Initial development concept for the Barossa project is proposed

2018:

- **March – National Offshore Petroleum Safety and Environmental Management Authority (NOPSEMA) grants initial environmental approval for the project.**

2021:

- **March – Santos announces Final Investment Decision (FID) for the $3.6 billion Barossa project.**
- June – Environmental Defenders Office (EDO), on behalf of Tiwi Islanders, requests that NOPSEMA review the approval of Santos' Barossa drilling environmental plan.
- November – NOPSEMA requests more information from Santos about stakeholder consultation and potential impacts on Tiwi Islanders.
- **December – A Federal Court challenge against Santos' environmental plan is lodged.**

2022:

- April – Santos submits a revised Offshore Project Proposal (OPP) to NOPSEMA.
- June – NOPSEMA approves Santos' revised OPP for the Barossa project.
- **September – Federal Court Justice rules that NOPSEMA's approval of Santos' Barossa drilling environment plan is invalid.** The court finds that Santos failed to properly consult Tiwi Traditional Owners. Drilling activities are suspended as a result of this ruling. The ruling invalidating NOPSEMA's approval caused a significant delay.
- October – Santos announces it will pause drilling activities and review the Federal Court decision.
- November – Santos submits a new drilling environment plan to NOPSEMA, incorporating more extensive consultation with Tiwi Islanders.

2023:

- March – NOPSEMA requests further information from Santos regarding the new drilling environment plan.
- April – Santos provides additional information to NOPSEMA in response to the regulator's request.
- **June – NOPSEMA approves Santos' revised drilling environment plan for the Barossa project**.
- **July – Environmental groups launch a new legal challenge against NOPSEMA's approval of Santos' revised drilling plan.**
- September – Federal Court dismisses the new legal challenge, allowing Santos to proceed with drilling activities.
- October – Santos announces the resumption of drilling activities for the Barossa project.
- November – Environmental groups file an appeal against the Federal Court's September decision.

2024:

- **January** – the Federal Court **dismissed the legal challenge** and lifted an injunction that had been preventing pipeline construction south of the 86km point. **The court found that certain claims made by the Environmental Defenders Office (EDO) and their expert witness regarding cultural heritage impacts were "confected" or fabricated, and that the EDO had engaged in "subtle witness coaching" and misrepresented Indigenous instructions.**
- The Court **ordered the EDO to pay Santos' legal costs** estimated at A$9 million.
- **Santos increases the budget for Barossa by A$500 million** due to delays caused by regulatory decisions and legal challenges.
- **Start-up of the project is pushed back to H2 2025.**

6. What conclusions can be drawn

6.1. Australia is attracting less investment

Investment across the natural gas and LNG value chain is recovering at a reasonably strong pace across most Peer Countries since the market lows observed between 2015 and 2020. But it is increasingly becoming clear that Australia is being left – E&A spend remains very low, LNG investment has declined and upstream proponents are focusing on sustaining, rather than growth, CAPEX.

E&A discovers the resources that can subsequently be produced, and E&A activity can be considered a leading indicator of overall future upstream gas production. In Australia, the current level of E&A activity remains well below long term averages and Australia attracts just 3% of total E&A investment dollars across the cohort of Peer Countries. Future upstream gas production may suffer as a result of the very low levels of current E&A activity.

While current upstream gas production investment does show signs of growth, this is focused on unconventionals and the backfilling of existing ullage, rather than growing overall production. The level of upstream gas production investment is likely based on sustaining CAPEX, and outside of a handful of projects in Western Australia, is not an investment in production growth.

The trend in LNG liquefaction is even more stark – Australia has been unable to attract capital, despite Peer Countries almost doubling their annual investment in the sector since 2020 amidst a global demand surge. The focus on maintaining and backfilling existing liquefaction plants amidst low levels of E&A investment and relatively low spending in upstream gas production results in a lack of drive to invest in expanding Australia's LNG export capacity by expanding or building new facilities.

But these trends are despite Australia's relatively attractive investment proposition from a fiscal and technical perspective. The challenge for Australia is an increasingly unstable and burdensome regulatory environment that is damaging investor confidence and reducing Australia's value proposition compared to competitors.

6.2. Political and regulatory uncertainty is challenging

While Australia's resources, access to markets, market certainty, fiscal terms, ability to raise finance and obtain social license are seen as positives that support investment in Australia – energy and climate policies, environmental regulation, permitting and approvals processes and the lack of regulatory and political certainty are driving investment down. Indeed, 95% of respondents to an Australian Energy Producers survey on Australia's competitiveness believe Australia's natural gas exploration, production and LNG sectors have become somewhat or significantly less attractive over the last 5 years.

Additionally, 95% of respondents to an Australian Energy Producers survey on Australia's competitiveness have had investments directly impacted by a change in Government policy or regulation. Of these, a fifth did not proceed or were relocated outside of Australia, and almost half were significantly delayed.

Australia, and specifically the East Coast Gas Market (ECGM), has been subject to ongoing state and federal government intervention since 2012 when various moratoria on onshore exploration and drilling were introduced in New South Wales, Victoria and South Australia. Intervention has increased over time, with various regulatory safeguards and voluntary mechanisms announced since the start-up of the Queensland LNG export projects linked the ECGM to the global LNG market for the first time. This intervention was in response to the perceived risks that the domestic gas market could fall short or suffer elevated gas prices during peak periods.

There have been more than 25 different interventions in the Australian oil and gas sector by Federal and State Governments since 2012.

As the global LNG market becomes increasingly competitive, the impact of Australia's regulatory burden on project costs and timelines becomes a critical factor in maintaining the country's position as a leading LNG exporter. Balancing regulatory objectives with international competitiveness remains an ongoing challenge for both policymakers and industry participants.

6.3. Permit and approval processes deter investment

Australia's natural gas and LNG project approvals process is a complex, multi-layered system involving federal, state, and local government agencies. This process, while designed to ensure thorough assessment of environmental, social, and economic impacts, has become increasingly challenging for industry participants. The resulting delays are having significant impacts on project economic viability, potentially threatening Australia's position as a leading global LNG exporter.

The multi-jurisdictional nature of approval creates a complex web of requirements, often with overlapping or conflicting demands. Evolving environmental and climate change policies can lead to changes in requirements during the approvals process. Increasing public scrutiny and activism require extensive stakeholder engagement, often leading to project modifications or delays. Stringent environmental requirements, particularly around greenhouse gas emissions, are becoming increasingly challenging to meet. Projects are also increasingly facing legal challenges from environmental groups or other stakeholders, even after receiving initial approvals.

All of these challenges are having significant impacts on project economics – increased CAPEX, market window risks, financing challenges and opportunity costs add up to reduce the attractiveness of Australia natural gas and LNG projects compared to those in Peer Countries.

6.3.1. Realising the CCS opportunity

Australia's CCS opportunity lies less in the reduction of domestic emissions, and more in enabling other countries' net zero ambitions. CCS is critical in Australia for future production of lower-carbon natural gas for domestic use and export. It can also decarbonise fossil power generation and hard-to-abate industrial sectors, such as cement, smelting and steel manufacturing. But Australia has far more geological CO_2 storage potential than it needs for domestic CCS. Wood Mackenzie estimate that Australia has at least 9.8 Gt of excess CO_2 storage capacity if all CO_2 emissions from the power generation and industrial sectors are captured and stored between 2030 to 2050.

Meanwhile, Australia's key trading partners, such as Japan and South Korea, have relatively high industrial emissions but limited domestic storage opportunities and are looking for regional CO_2 storage solutions. This highlights an economic opportunity for Australia to be a regional CCS hub. And yet, Australia is not the only country with regional hub potential in Asia Pacific. Indonesia and Malaysia are also endowed with abundant geological CO_2 storage potential and have clear ambitions to be the region's preferred CCS hub.

Australia will need to demonstrate strong competitiveness to fight for investment capital in the sector. As CCS is mostly considered an additional cost to industry, achieving competitive costs for CO_2 capture, transport and storage will be critical to successfully growing local capacity. This will require strong Government support for the sector, stable and sensible regulation, a streamlining of project approval processes to ensure projects can be delivered quickly, efficiently and at a competitive cost, and bilateral agreements to be put in place as a matter of urgency to allow for the import and export of CO_2 for storage.

6.4. What can be done

With the Federal Government's Future Gas Strategy making clear the critical, long-term role for gas in this country, the need to encourage investment in the development of Australia's gas resources is obvious and pressing. Streamlining the process for exploration, appraisal and development approvals is critical to lowering investment risk. Recognising the vital role of gas in the energy transition and supporting it with appropriate policies is key to providing industry with the confidence it needs to invest. Approvals timeframes should not be indefinite, and when approvals are given, there needs to be more certainty that they can be relied upon.

This year's review of the Gas Market Code, the LNG exporters Heads of Agreement and the ADGSM are an opportunity for the government to reshape its relationship with the industry, provide the incentives and certainty needed to boost investment sentiment and support one of Australia's most significant domestic and export industries.

Australia remains an attractive destination for natural gas, LNG and CCS investment – but without improvements in policy and regulation, and an increase in the stability and efficiency of processes, Australia risks become uncompetitive in the fight for investment capital – not just across the natural gas and LNG sectors, but in new energy sectors such as CCS that have high potential growth trajectories.

Appendix A – Key assumptions and methodologies

Wood Mackenzie's approach incorporates primary research to strengthen our in-house deep industry and regional knowledge. This research is combined with public domain information to generate high-quality proprietary data and analysis. Primary external data sources include direct interviews with energy sector companies and government departments, government publications and regulatory information, company annual reports and other documentation, general and industry-specific media, third-party commercial data providers, and academic material. In addition, Wood Mackenzie data are subject to a rigorous integrity checking and quality control process and has developed a comprehensive set of checks, which are carried out on a regular basis, at a field, play, basin, country, region, and global level.

Exploration and appraisal

Exploration and appraisal capital expenditure (CAPEX) are based on Wood Mackenzie analysis of company costs incurred in exploration activities in Securities Exchange Commission (SEC) filings for the study period. Companies typically disclose their exploration and appraisal costs on a regional basis. Wood Mackenzie allocates this regional figure by basin. This allocation is based on:

- The number and estimated cost of net exploration and appraisal wells in which each company has participated in each basin in each year
- An estimate of material seismic and other non-drilling costs such as general & administrative costs (G&A)

In the case of where a company did not provide SEC disclosure, local company reports or an estimate for exploration costs, Wood Mackenzie estimates exploration investment in the basin in each period by using Wood Mackenzie database of net wells drilled in this period by the company.

Upstream gas production and midstream gas & LNG processing

Wood Mackenzie models capital expenditure at the field or field grouping level and classifies field type by hydrocarbon, depending on the composition of reserves. These field types are determined as:

- **Gas –** gas accounts for 80% or more of total reserves
- **Gas/Condensate –** must contain gas and condensate reserves greater than 20% but less than 80% of total reserves. Condensate should have a gravity of 45 °API or higher.

Upstream gas production CAPEX include:

- **Production facilities**: Platforms, TLPs & FPSOs: e.g. jacket, piles, substructure, topside structure, including accommodation facility, drilling facilities.
- **Processing equipment**: Any facilities related to topside production systems: e.g. compressors, pumps, separators, dehydrators, processing modules, chemical systems.
- **Subsea**: Templates, subsea Xmas trees, manifolds, subsea processing units, control units (electrics/valves).
- **Development drilling**: Site preparation, rig costs, personnel, materials, completions, fracking (does not include exploration costs or seismic).
- **Pipeline**: Survey, pipeline construction/coating/laying, flowlines from satellites to host platform (including subsea completion), parallel lines (water injection/umbilical systems), risers.
- **Offshore Loading**: Offshore loading systems, for example, floating buoys.

Midstream gas & LNG processing CAPEX include:

- **Terminal**: Any onshore systems related directly to producing fields.
- **LNG plant cost**: All expenses associated with the liquefaction facilities and integrated pipeline costs when attributed to the LNG section of the projects.
- **Other capex**: Anything not directly covered by the above categories, including unallocated sustaining capex.

CCS

For the purpose of this report, CAPEX is only analysed for projects above 0.5 mmtpa nominal capacity with emission sources being upstream oil & gas production and midstream gas processing, pre-combustion CO_2 capture type. CAPEX assessment includes expenditure for capture, transport and storage. Wood Mackenzie's proprietary CCS valuation model is used to determine the annual CAPEX allocations for each project based on project specific assumptions. For projects without a valuation model, we apply a levelised cost of CCS CAPEX across the value chain – capture, transport, and storage. In these cases, investments are spread over three years from the project's FID, with allocations of 15%, 45%, and 40%.

Disclaimer

Strictly Private & Confidential

Wood Mackenzie™ is a trusted provider of data, analytics and insights, establishing us as the global research and consultancy business powering the natural resources industry. Our dedicated oil, gas & LNG, power & renewables, chemicals, and metals & mining sector teams are located around the world, giving our clients first-mover advantage. For more information visit: **woodmac.com**

Europe:	+44 131 243 4400
Americas:	+1 713 470 1600
Asia Pacific:	+65 6518 0800
Email:	contactus@woodmac.com
Website:	www.woodmac.com

Wood Mackenzie