



10 October 2025

To: Economics and Industry Standing Committee

Re: Inquiry into the role of Western Australia in the global effort on decarbonisation

Thank you for the opportunity for the Institute for Energy Economics and Financial Analysis (IEEFA) to provide input to the Economics and Industry Standing Committee's *Inquiry into the role of Western Australia in the global effort on decarbonisation*.

IEEFA is an independent energy finance think tank that examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy.

The key points of our submission are as follows:

- Green iron represents a major economic opportunity for WA, but pathways that prolong fossil fuel use should be avoided. Direct reduced iron (DRI) is an existing, mature technology that offers the most viable pathway for green iron production.
- The use of methane gas in DRI plants should be minimised as it would put pressure on domestic gas supplies and increase emissions, WA faces international competitors who are better placed to produce gas-placed DRI. Carbon capture and storage (CCS) is unlikely to be effective in decarbonising iron production.
- Green iron requires the use of green hydrogen, made using renewable energy. WA should aim to include a proportion of green hydrogen in all future DRI plants with the aim to ramp up use as it becomes more affordable.
- Liquefied natural gas (LNG) exports from WA face an uncertain outlook amid a looming supply glut and uncertain demand.
- LNG is unlikely to displace coal for power generation in emerging markets as LNG is relatively expensive and uncompetitive. Where gas has replaced coal, its position is being eroded by renewables and battery storage.
- China is the world's largest LNG importer, but its significant domestic gas production and changes in its economic output indicate limited prospects for demand growth. In India the share of gas generation in the electricity sector fallen, with LNG demand growth unlikely.

Kind regards,

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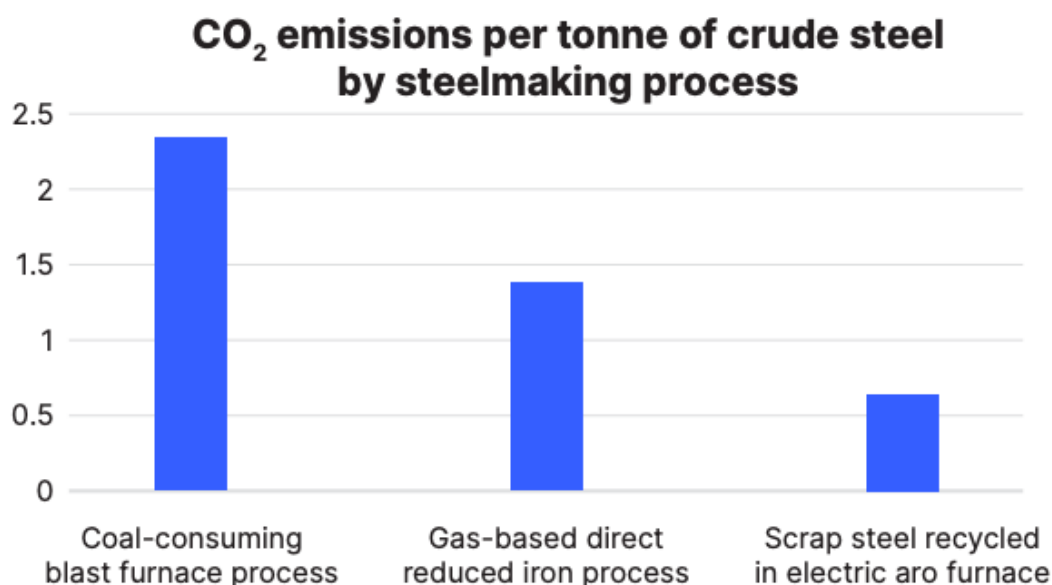
Green Iron and Carbon Capture and Storage

There is growing global interest in the emerging “green iron” space. This involves a decoupling of iron and steel production, relocating the ironmaking step to regions that have both suitable iron ore and renewable energy resources to avoid the use of fossil fuels in the reduction process.

Direct electrification technologies for the processing of iron ore to iron, powered by renewable energy, are under development both in Australia and overseas. However, until such pathways reach commercial maturity, green iron looks set to use an existing, mature technology – direct reduced iron (DRI).

In the Middle East, DRI is widely used in the steel sector and runs on methane gas. The steel produced is lower-emissions than coal-based production but is still emissions-intensive, producing 1.4 tonnes of carbon dioxide (CO₂) per tonne of steel. Steel produced in this way cannot be considered “green” or “low-emissions”.

Figure 1: Relative emissions intensity of steelmaking pathways



Source: World Steel Association

The key providers of DRI technology – Midrex and Energiron – have made clear that their technology is ready to run on green hydrogen. In northern Sweden, Stegra has a new steel plant [under construction](#) that will start commercial-scale operations next year, with the DRI plant running on 100% green hydrogen. The iron and steel produced can be considered to be “green”.

In WA, the trading arm of Thyssenkrupp – a major German steelmaker – has [signed](#) a memorandum of understanding to be the offtaker of green hydrogen-based iron from Progressive Green Solutions’ Mid-West Green Iron Project.



You can't make green iron with gas

The emissions-intensity of gas-based DRI means that [you can't make green iron with gas](#). At best, gas-based DRI can be considered “grey iron”. A fleet of DRI plants running on gas across WA would significantly increase the emissions of both the state and the nation.

In addition, a DRI plant uses a lot of gas. BlueScope has [noted](#) that switching its Port Kembla steel plant from coal to gas-DRI of equivalent capacity would require 30 to 40 petajoules (PJ) of gas per year. With the Australian Energy Market Operator (AEMO) [warning of gas shortages](#) in both the east coast market and WA, there are questions as to whether DRI plants could be adequately supplied and what effect their demand would have on domestic gas prices.

Carbon capture and storage can't make “grey iron” green

Carbon capture and storage (CCS) is in no position to make grey iron green. Midrex, the world's leading provider of the DRI technology that WA's green iron opportunity will be based on, has recently made clear its views on CCS, [stating](#) that “its practical use in steelmaking remains limited.”

Midrex added: “Carbon Capture and Storage (CCS) is sometimes hailed as a ‘silver bullet’ that can play a major role in decarbonizing heavy industries. In reality, it is only one of many approaches and technologies that could play a role in reducing emissions from the iron and steelmaking industry. Most Direct Reduction plants lack access to users or local CO₂ storage sites on a scale that could make CCS commercially viable. Transporting the CO₂ long distances to such sites is too expensive.”

The company further stated, “Despite being promoted as a decarbonization tool for heavy industry, CCS has delivered limited success in practice.”

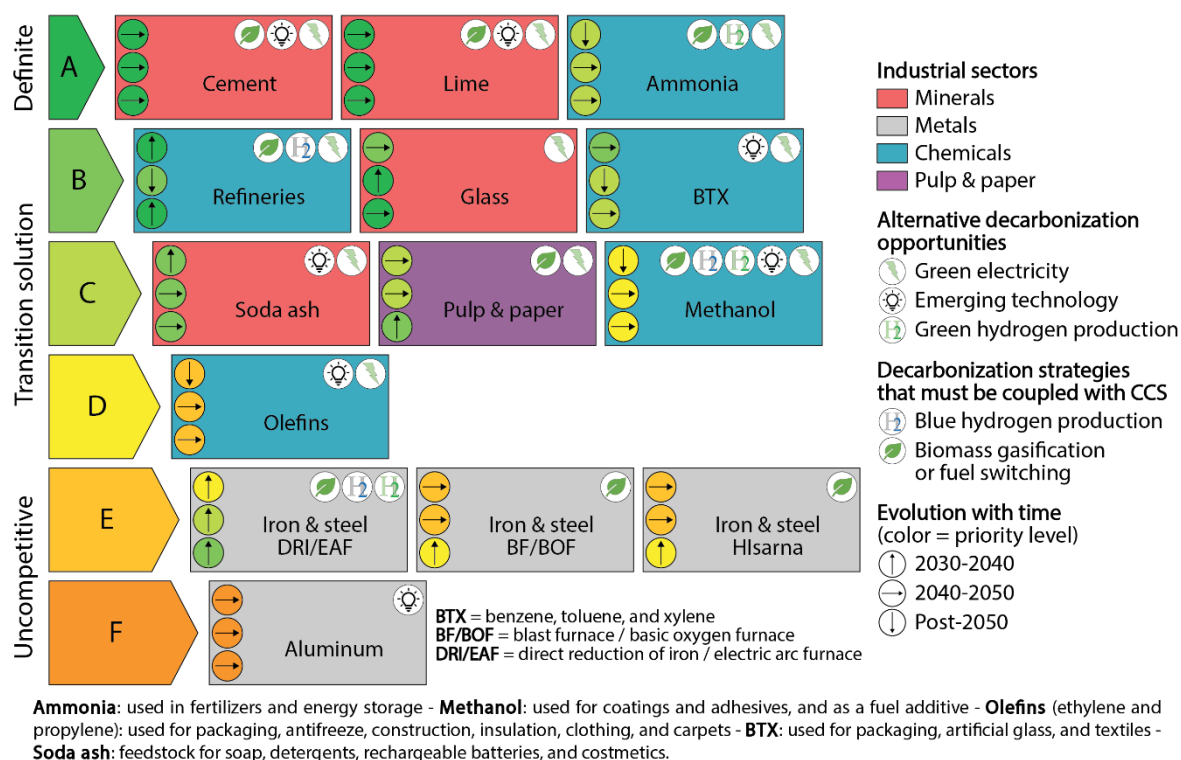
CCS is often cited as being a key solution for decarbonising so-called “hard-to-abate” industries. However, although CCS may play a role in decarbonising some industrial sectors, such as cement, it looks unlikely to play a major role in others. In 2024, the Kleinman Center for Energy Policy at the University of Pennsylvania published a [CCS Ladder](#), ranking the suitability of CCS to industrial sectors using five criteria:

- Feasibility
- Mitigation potential
- Availability of alternative decarbonising technology
- Potential to lock in emissions-intensive technology or fossil fuel use
- Geospatial dispersion

The ladder ranked the application of CCS to iron and steelmaking as “uncompetitive” (Figure 2).



Figure 2: CCS ladder for industrial decarbonisation



Source: Kleinman Center for Energy Policy.

There is only one commercial-scale CCS plant for iron and steelmaking anywhere in the world – the [Al Reyadah project in the UAE](#), owned and operated by Adnoc. This installation, located at a DRI-based steel plant owned by Emsteel, captures only around 25% of the total emissions of the plant.

In no way can the iron and steel produced be considered “decarbonised” or “green”. The captured carbon is used by Adnoc for enhanced oil recovery (EOR), helping to get more fossil fuels out of the ground and leading to more carbon emissions. Without the EOR element of the project, it seems unlikely the project would ever have been constructed.

In the nine years since the Al Reyadah project became operational, not a single commercial-scale CCS project for iron and steelmaking has come online anywhere in the world. Emsteel is [now piloting the use](#) of green hydrogen for DRI and recently [delivered](#) its first steel made using green hydrogen.

The project of pipeline of commercial-scale CCS projects for iron and steel is not impressive. The [Global CCS Institute's \(GCCSI\) 2024 Global Status report](#) tracked six projects under development but the lack of available detail for some of these projects casts significant doubt over their development status and timelines.

In all six cases, the GCCSI is unable to confirm important aspects of the projects. For every project, at least one category of “operational year”, “capture capacity” and “storage type” is



listed as “under evaluation” by GCCSI. Two of the three projects classified as being in “advanced development” don’t have a disclosed date that they plan to become operational. For half the projects, the CO₂ capture capacity is unknown, and no information about carbon storage or usage is disclosed for any of them. Furthermore, the total carbon capture capacity for these projects (where it is disclosed) amounts to a minute fraction of global steel’s emissions – just 0.13%.

IEEFA has been analysing CCS across a range of sectors for many years, including for iron and steel. Our most relevant publications on CCS for iron and steel can be found at the below links:

[Carbon Capture for Steel? CCUS will not play a major role in steel decarbonisation](#)

[Steel CCUS update: Carbon capture technology looks ever less convincing](#)

[Carbon capture delusion risks diverting South Australia from green iron and steel](#)

How can WA be a green iron leader?

Green iron requires the use of green hydrogen, which is made using renewable energy.

To become a global pioneer of truly green iron, and enjoy the economic benefits it brings with it, WA needs to avoid going down a CCS technology pathway – an emissions dead end due to the limitations on the performance and affordability of CCS. Blue hydrogen is produced using methane gas with CCS. As a result, blue hydrogen is held back by its reliance on carbon capture and [cannot be considered to be truly low-emissions](#).

Japanese steelmakers [JFE Steel](#) and [Kobe Steel](#) already have plans to import gas-based DRI from the Middle East to Japan, indicating that the region [has a head start](#) over WA. WA is unlikely to be able to compete in gas-based DRI with the Middle East, where DRI is already well-established and cheap gas is plentiful.

Despite the availability of cheap gas in the region, iron and steelmakers in the Middle East are already starting to turn to green hydrogen. In addition to Emsteel, Meranti Green Steel is planning to build a new DRI plant in Oman that will [start on 15% green hydrogen](#) and 85% gas and then progressively ramp up green hydrogen use from there. Meranti aims to take a final investment decision on this project by the [middle of 2026](#). Oman is targeting early use of green hydrogen in new ironmaking projects with the requirement that at least some green hydrogen is used from 2030.

This sets a benchmark for WA. Future DRI plants in the state should start with a similar proportion of green hydrogen along with an ambitious timetable to ramp up green hydrogen use as it becomes more available at lower cost. Starting with 15% green hydrogen would indicate that ironmaking in WA is [on a technology pathway that can genuinely produce green iron](#), rather than relying on 100% gas and CCS, which cannot.



Green hydrogen needs government support at this stage and there is an [opportunity for this to be smarter](#). Support for green hydrogen projects should take the end use of the hydrogen into account, so that government backing is focused on end uses that make economic sense, such as ironmaking and other domestic sectors where hydrogen is already used. The International Energy Agency (IEA)'s recent [Global Hydrogen Review 2025 report](#) echoed this call to target support for hydrogen use in existing applications. This includes DRI, where in current gas-based DRI the methane gas is reformed into hydrogen and carbon monoxide.

Early action to promote truly green iron in WA is increasingly important as international competition is growing. [Brazil](#) and [Canada](#) have both the high-grade iron ore needed to use current DRI technology, as well as regional power grids where clean energy dominates and can be used to make green hydrogen.

Green iron represents a major economic opportunity for WA, but it needs to avoid technology choices that prolong the use of fossil fuels unnecessarily and would lead the state to being stuck making grey iron.

Liquified Natural Gas

LNG is unlikely to displace coal, but could displace renewables

A key assumption underpinning arguments that liquefied natural gas (LNG) exports from WA will enable decarbonisation in emerging markets in Asia is that LNG generation will displace coal generation. For example, [Woodside CEO Meg O'Neill](#) said that "Curtailling new LNG supply from Australia runs the risk of prolonging dependence on coal among emerging economies in the region."

Western Australia's Premier, Roger Cook, has made [similar arguments](#), suggesting that WA's total emissions were immaterial relative to those from the use of coal in Asia, and that LNG exports would allow Asia to move away from coal.

However, the available evidence strongly suggests that LNG is unlikely to materially displace coal in electricity generation in Asia given LNG is relatively expensive and uncompetitive with both coal and other sources of gas (such as domestic gas or pipeline imports). This highlights an important distinction between gas and LNG – while coal-to-gas switching may have occurred in some regions, most notably the US, the high cost of LNG relative to coal means coal to LNG switching is likely to be very limited.

[The IEA](#), for instance, found that LNG prices would need to be USD3-5 per million British thermal units (MMBtu) to drive material coal-to-gas switching in emerging markets, but this is well below the price needed to justify new LNG projects (USD8/MMBtu). This leaves the LNG industry at an impasse – prices are likely to be too high to trigger new demand from coal-to-gas switching, but too low to justify new LNG expansion.



This may explain why China and India, the two largest coal consuming countries by far, have not seen LNG (or gas) displace coal in their electricity systems. Together, China and India [accounted](#) for 71% of global coal consumption in 2023, compared with just 5% for countries in South-East Asia, meaning any material displacement of coal in Asia will be determined by market developments in China and India.

While LNG is not likely to materially displace coal, the US Department of Energy found that high US LNG exports could [displace renewable energy](#) rather than coal.

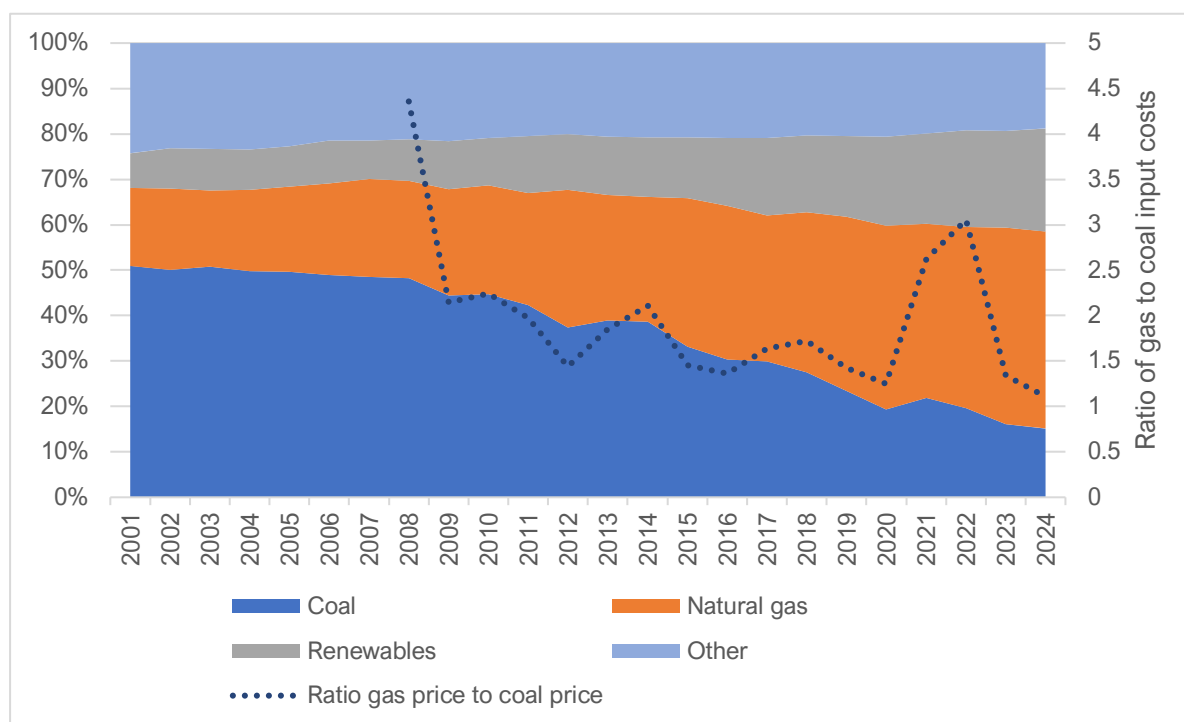
Cheap gas – and renewables – have displaced coal generation in the US

The electricity sector in the US is often presented as an example of coal-to-gas switching, with growing gas and renewable generation coinciding with declining coal generation (Figure 3). However, growing gas generation in the US arguably reflects that gas is highly competitive with coal for electricity generation.

The US shale boom resulted in gas prices falling materially, and by 2020 gas input costs were almost at parity with coal input costs (on an input cost basis).

However, the growth in gas generation is already coming under threat, albeit at the margins, from the deployment of battery energy storage systems, most notably in California, which currently sources about half of its electricity from gas. Recent analysis found that energy storage facilities [met about 28%](#) of evening electricity demand from January to August 2025, up from about 4% in 2022. Meanwhile, gas generation fell by over 42% in just two years.

Figure 3: Falling gas costs drove coal-to-gas switching in the US



Source: US Energy Information Administration, IEEFA.



Declining battery costs are likely to see further displacement of gas, particularly in evening peak periods.

China's breakneck rollout of renewable energy is displacing coal

In China, [growing electricity demand](#) has meant that absolute generation from coal, gas, wind, solar and nuclear has increased over the past decade. However, the share of gas generation has largely stagnated, remaining below 3%, while the share of renewable generation quadrupled from 4% to 16% in the eight years to 2023. Meanwhile, the share of [coal generation](#) fell from 72.5% to 58.2% from 2014 to 2024, clearly indicating that the surge in renewable energy is displacing coal rather than LNG.

Cost is a key driver of the limited penetration of gas generation. IEEFA previously found that the levelised cost of coal generation ranges from USD40-60 per megawatt-hour (MWh), whereas gas generation ranges from USD70-110/MWh. The [levelised costs](#) of onshore wind with storage and solar with storage are now forecast to be lower in China than natural gas generation.

This trend is likely to [continue](#), with recent gas plant capacity additions dwarfed by the rollout of renewable energy and coal energy generation capacity. Of a forecast USD8.63 trillion in capital expenditure to upgrade China's power system to 2060, only 9% is forecast to be allocated to fossil fuel generation.

However, even if China were to increase its use of gas in electricity generation, it is not apparent that this would translate into additional LNG demand. While China is the world's largest LNG importer, its imports in 2024 accounted for [less than one third](#) of its gas consumption. China's significant domestic gas production, as well as pipeline imports from other countries, represent the lion's share of China's gas supply.

Beyond the power system, which accounts for 61% of China's coal consumption, China [consumes coal](#) in steelmaking (23%) and cement production (6%), with buildings and other uses accounting for 10% of consumption. However, changes in China's economic output, particularly residential construction, are predicted to reduce steel and cement demand. Steel and cement output are subsequently forecast to fall by 8% and 25% this decade.

In the longer term, there is potential for greater gas use in DRI processes, but recent [investment trends](#) point to little future growth in gas use in steelmaking, given there will 389 million tonnes of new (or replacement) coal-based blast furnace capacity added this decade, compared with only 4.3 million tonnes of new non-blast furnace capacity (which might use gas).

India has turned towards coal as lower-cost domestic gas production declines

India's experience has been markedly different from that in China. Since 2010, the share of coal generation in the electricity sector has increased while [gas generation has fallen](#) materially, with its share in FY2025 below 2%. Meanwhile, the share of generation from renewable energy more than quadrupled, rising to 14% in FY2025.



The decline in the share of gas generation coincided with declining Indian domestic gas production, which is less costly than LNG, and occurred despite India being an LNG importer, with proximity to major LNG suppliers, such as Qatar.

This, again, reflects a lack of competitiveness. Indian government [analysis](#) found that the historic weighted average cost of oil and gas (as electricity sources) grew over the past near decade, and they are now materially more expensive than coal, solar or wind generation.

The [fall in gas generation](#) has resulted in lower utilisation of gas plants, with increasing stranded asset risks. Low utilisation of existing plants could see gas generation grow in future, but again, increasing use of LNG in power generation is likely to require low LNG prices, estimated at about USD 5-5.75/MMBtu.

The [outlook](#) for new gas generation capacity is also bleak, with only one new plant added since 2016 and government policy stating that no new gas power plants will be built this decade.

Similar to China, the majority of India's coal consumption is in the [electricity sector](#), which accounts for 70% of total consumption, followed by steel (6%), cement (1%) and other sectors (22%). However, steelmaking has seen very limited LNG demand growth since 2016, at just 0.08 billion cubic metres (bcm) – equivalent to about one LNG cargo – and while there is potential for increased gas use in some industrial processes, this will depend on new distribution infrastructure being developed and on LNG prices. Generally, LNG demand growth in these sectors has been marginal compared to consumption of domestic gas.

Additional LNG will not be needed for energy security due to a looming supply glut and uncertain demand

LNG proponents often cite energy security as a key rationale for continued investment in and expansion of LNG export infrastructure. However, the future of LNG markets is highly unclear, with an unprecedented wave of new supply and uncertain demand meaning LNG markets will soon see a supply glut. The key question, from an energy security perspective, is whether there will be enough demand growth to absorb all of the new LNG supply, and when might this occur.

On the supply side, LNG markets will see new capacity of [about 360bcm](#) (about 14,400PJ) come online by 2030, an increase of about [60%](#). This is by far the largest LNG capacity addition in the history of the sector, with a large portion of this new supply coming from low-cost supplier Qatar.

Much of this new LNG capacity has not yet been contracted to end buyers, in part because a sizeable share of recent LNG contract signings have been with [portfolio traders](#) rather than end users. Columbia University's Centre on Global Energy Policy estimates that [78bcm \(about 3,120PJ\) of Qatari LNG](#) is either uncontracted or contracted with a portfolio player that will need to find a buyer. Shell, the largest independent LNG trader, is expected to have [40 million tonnes \(about 2000PJ\) of uncontracted LNG](#) on its books by 2030 (although IEEFA notes some of this may be from Qatar). To put this into context, WA's total LNG export volumes in 2024 were 3,355PJ.



In light of the new capacity coming online, the IEA has [forecast](#) that existing and under-construction LNG capacity will be sufficient to meet future LNG demand until 2040 under its slowest scenario for energy transition (aligned with 2.4°C of global warming). Under scenarios based on faster transitions, existing and under-construction LNG capacity will be more than sufficient to meet all future LNG demand, and will likely result in lower utilisation and returns, with many under-construction plants unlikely to recover their capital costs.

Meanwhile, future LNG demand is highly uncertain, with demand in mature markets either [falling or expected to soon fall](#). Japan, until recently the world's largest LNG importer, saw LNG imports fall by 25% over the past decade, and they are expected to [fall further](#) under government policy. IEEFA also [anticipates](#) that LNG demand in Europe will fall from almost 158bcm in 2025 to 127bcm in 2030 (a fall of about 1,240PJ). Similarly, LNG demand in South Korea is [forecast](#) to fall by 20% to 2030, with government targets to reduce the share of gas in the electricity system from 28% to 10.55% in 2038, which may further impact on LNG demand.

The LNG industry anticipates emerging markets will be a [key driver of future LNG demand growth](#), but future demand growth is highly uncertain. In May, Jean Abiteboul, president of the [International Group of Liquefied Natural Gas Importers](#), stated that “the trajectory of demand remains deeply uncertain, influenced by conflicting market drivers.”

LNG industry insiders are also sounding the alarm about future demand uncertainty, with the CEO of the proposed US Gulfstream LNG project [expressing concerns](#) about the ramp-up in US LNG supply in the face of uncertain demand. Wood Mackenzie [highlighted](#) increasing concerns about demand in China, which “remains the big hope to absorb much of the new LNG supply coming to market”. LNG imports in China fell by 18% year-on-year in the first eight months of 2025, and there are questions about future structural LNG demand in China due to the rollout of renewable energy (including a new 60-gigawatt hydro plant) and the potential for increased pipeline gas supply from Russia.

In South-East Asia, hopes for a spike in LNG consumption for electricity generation are being hampered by [gas turbine shortages](#), which is likely to delay new projects in Vietnam and the Philippines beyond 2030. These delays will impact on LNG demand and potentially create space for additional renewable energy deployments in the meantime.

In Pakistan, which was expected to see significant LNG demand growth, growing solar generation has starting reducing gas demand, leading Pakistan to request that LNG sellers allow it to reduce its contracted volumes. This is likely to be a sustained trend, with [Pakistan's Petroleum Minister](#) Ali Pervaiz Malik stating: “This is not a temporary blip.”

Meanwhile, Australia's second largest LNG buyer, Japan, is increasingly reselling Australian LNG into other markets as its own demand declines. [IEEFA estimates](#), based on reliable shiptracking data, that Japanese companies resold between 627PJ and 812PJ of Australian LNG into other markets in 2024, more than the total gas consumption in either eastern Australia or Western Australia. Most of this LNG was sold into Korea and Taiwan. LNG from Australia also accounted for 41% of Japanese company LNG resales in 2024, higher than from any other LNG exporter.



Crucially, it is not the case that Japanese companies are merely reselling surplus LNG due to being overcontracted. Shiptracking data clearly shows that the volume of Australian LNG that landed in Japan was similar to total contract volumes. Japanese resales also include a large component of spot LNG purchases from Australia, which are then resold into other markets.

Reselling of LNG is not new, and certainly not unique to Japanese LNG traders. However, the scale of Japanese company resales of Australian LNG highlights the commercial interests that Japan has in Australian LNG, and provides context for frequent claims that Australian LNG is required to keep the lights on in Tokyo.