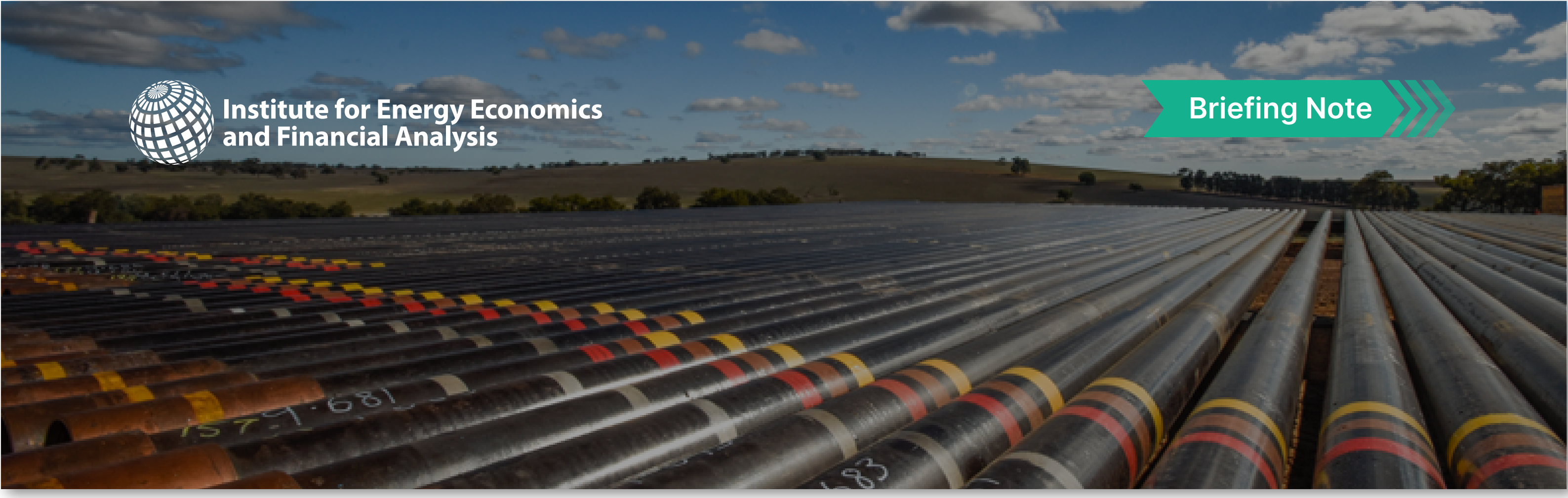

March 2025
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Reining in Western Australia's gas addiction

Targeted action could help cut consumption

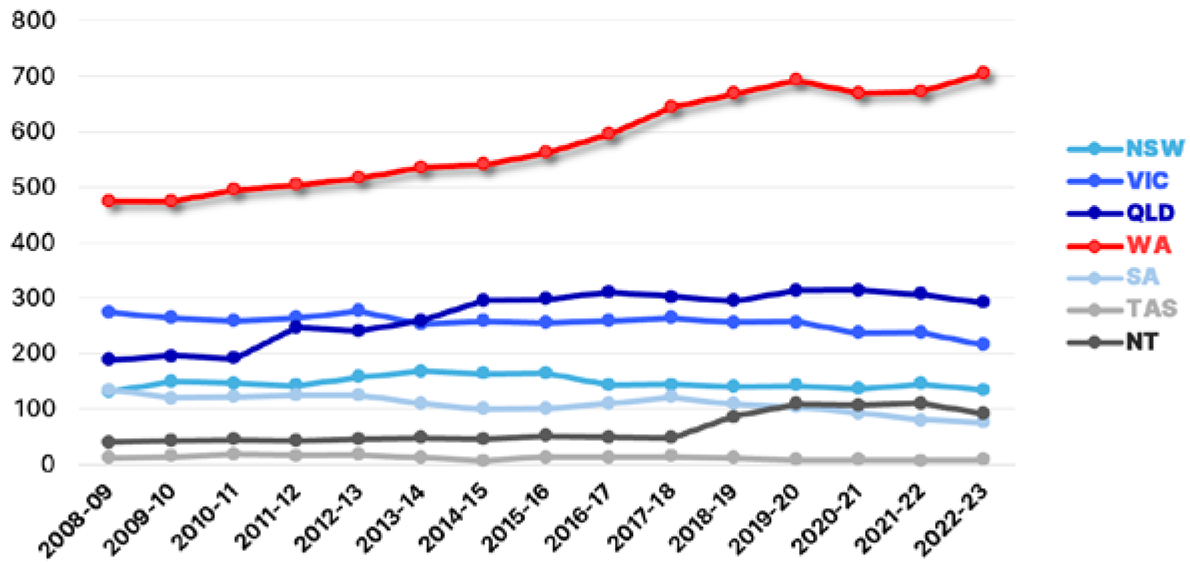
- *Western Australia's gas consumption – already the highest in Australia – is forecast to continue growing over the next decade, fuelled by industrial developments.*
- *Eighty-four percent of WA's gas use is spread across four sectors: LNG processing, electricity generation, alumina refining and ammonia production.*
- *WA's electricity system lags eastern Australia on the transition to renewables and batteries, in particular at remote mining and industrial sites that are heavily reliant on gas-based electricity.*
- *Available technologies can significantly reduce gas use in LNG, ammonia and alumina production, but stronger incentives and support are urgently needed.*

State's high gas demand concentrated in a handful of sectors

The Australian Energy Market Operator's (AEMO) latest Western Australia Gas Statement of Opportunities (GSOO) provides a forward-looking assessment of Western Australia's (WA) gas market, highlighting the state's ongoing reliance on gas and potential future challenges stemming from projected growth in industrial demand.

WA is already by far the largest gas user in Australia, with demand growing 37% since the 2013 fiscal year (FY) to account for almost half of national consumption (Figure 1). Roughly 60% of the growth in WA's gas use over this period is due to increased liquefied natural gas (LNG) production, with the remainder largely due to increased gas-powered electricity generation. WA is the only Australian state or territory where gas use has increased in recent years (since FY2020), with other regions recording greater uptake of renewable energy and reduced industrial activity in comparison.

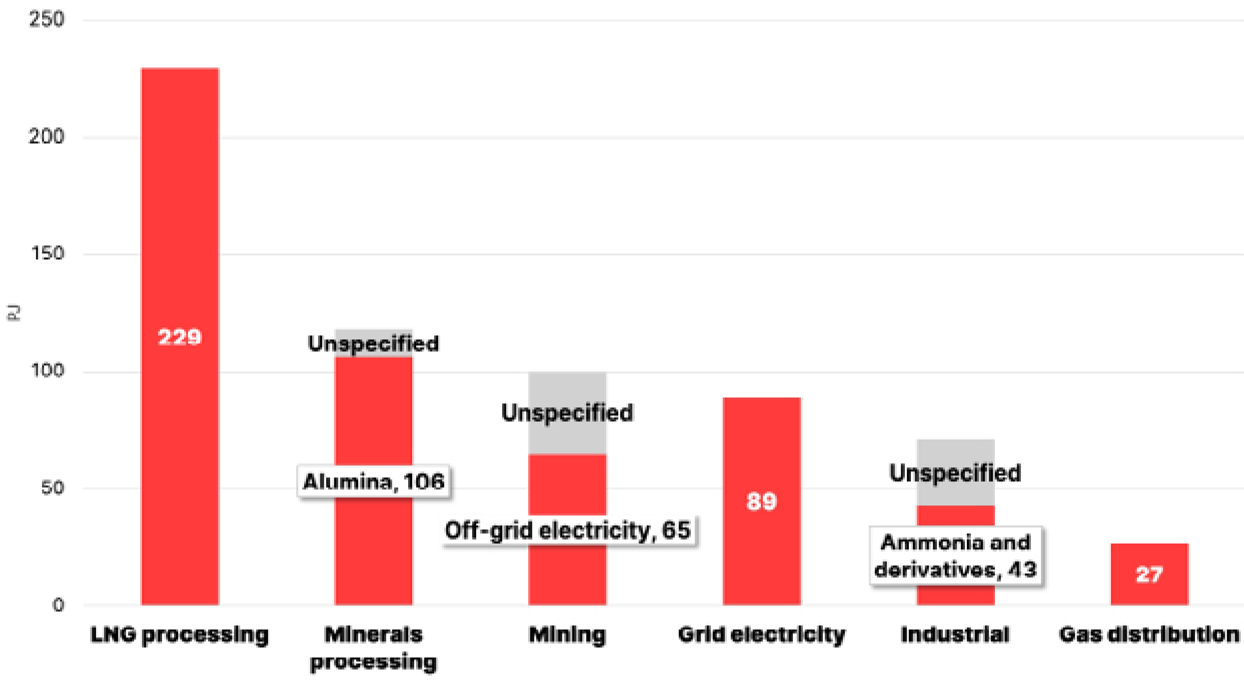
Figure 1: Annual gas consumption by state and territory (petajoules/PJ), 2013-2023



Source: Department of Climate Change, Energy, the Environment and Water (DCCEEW), Australian Energy Statistics 2024, Table C.

WA's gas demand is concentrated in a handful of sectors, with 84% of total consumption split between LNG processing (36%), electricity generation (24%), alumina refining (17%), and the production of ammonia and derivative products (7%) (see Figure 2). Residential and commercial use only represent about 2% of the state's total gas consumption. About half of all WA gas is consumed in the north-west of the state (the Dampier, Pilbara and Karratha Gas Bulletin Board zones), primarily in LNG plants, though large amounts are also used to generate electricity in off-grid mine sites and at the Yara Pilbara Fertiliser plant on the Burrup Peninsula. Most of WA's remaining gas is used in the Perth Metro, South-West, and to a lesser extent Goldfields zones, largely in alumina plants or to produce electricity for the South-West Interconnected System (SWIS).

Figure 2: WA gas consumption by user (PJ), 2024



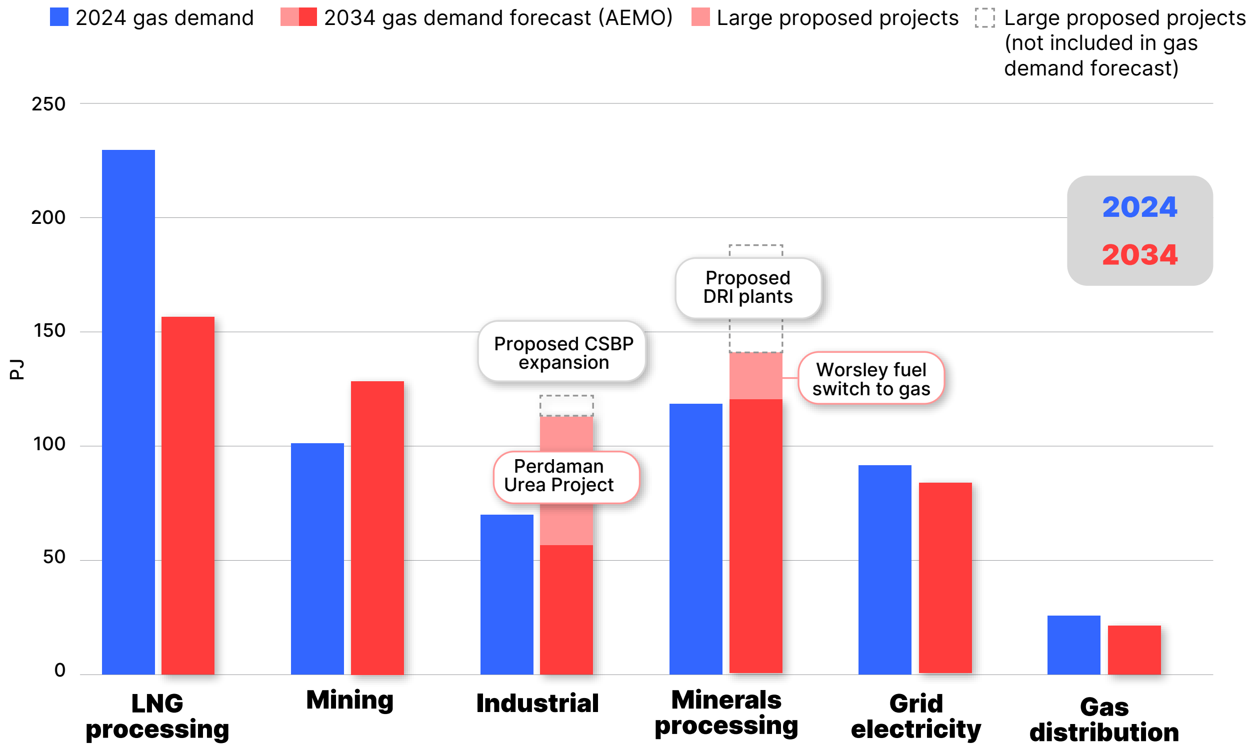
Sources: IEEFA analysis based on WA Gas Bulletin Board data for large gas users and WA GSOO 2024, Figure 3.

Proposed projects could drive WA's gas demand even higher

Gas demand in WA is expected to remain strong to 2035, with annual consumption fluctuating between 600PJ and 700PJ in the GSOO forecasts. In 2034, WA gas demand excluding LNG processing is forecast to be 19% higher than 2024 levels. Gas used in LNG processing is forecast to decline by 32% to 2034 – a significant reduction given its role as a major demand source. It is worth noting that this forecast does not seem to include the development of the Browse gas field, which if confirmed would drive a material increase in gas use.

The GSOO forecasts suggest the decline in LNG processing will offset by increased gas consumption in minerals processing, mining and other industrial sectors such as ammonia. From 2028, this will ramp up as numerous projects commence, restart or expand operations (Figure 3)). A slight decline is anticipated in gas-based generation for grid electricity, though gas is expected to play an ongoing firming role to support grid reliability and stability during the transition to renewable energy.

Figure 3: Gas demand by user category, 2024 and 2034



Sources: IEEFA analysis. Current gas use is based WA Gas Bulletin Board data for large gas users and WA GSOO 2024, Figure 3. Future gas use is drawn from WA GSOO 2024, Figure 11. Specific project gas use is calculated from public information.

A handful of proposed WA projects could add more than 130PJ of gas demand in coming years, such as:

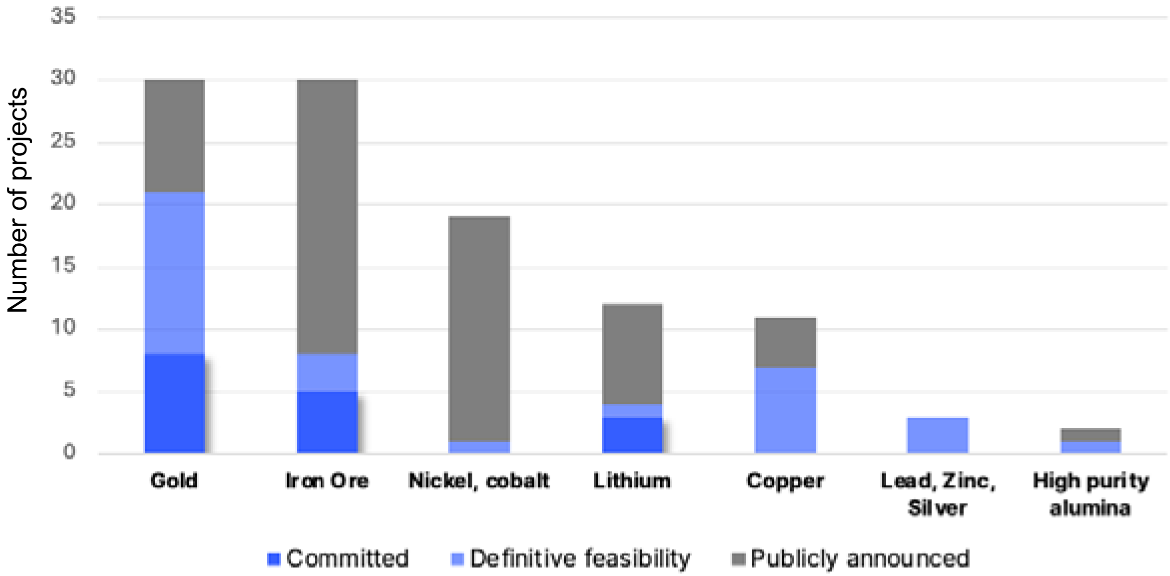
- Perdaman's Karratha urea project, which will produce ammonia and its derivative urea (see Figure 3, Industrial), is expected to be operational from 2028, and could use up to 55PJ of gas annually. There are no firm commitments to reduce future gas use outlined in the project's Greenhouse Gas Management Plan.
- Ongoing conversion of coal-fired boilers at the Worsley Alumina refinery (see Figure 3, Minerals processing) could add about 20PJ to gas demand once complete, equivalent to about 20% of existing gas use in WA alumina refining.

- Gas-based direct reduced iron (DRI) projects, such as Green Steel WA's Mid West Hydrogen DRI Plant and POSCO's Port Hedland Green Steel Project also target operations in 2028 and 2031, respectively, with final investment decisions expected in 2025. Once operational, both projects would initially rely on gas to process iron ore into iron, which IEEFA estimates would add a further 47PJ of demand.
- CSBP Limited has proposed a new 300,000 tonnes per year ammonia plant, which IEEFA estimates would use about 10PJ of gas annually, sourced from the Dampier to Bunbury Natural Gas Pipeline. A final investment decision was expected in 2024 but does not yet appear to have progressed.

Of the above, the GSOO gas demand forecasts only include Perdaman's Karratha urea project and Worsley's conversion of coal-fired boilers. The report makes no mention of future DRI projects or expanded ammonia capacity at the CSBP plant. This means that if these projects proceed, 57PJ of gas demand could come online in WA by 2030, on top of the GSOO forecasts.

Although the GSOO provides limited information on smaller projects driving the demand forecasts, there are many emerging sources of gas demand by 2035. WA has more than 100 metals and minerals projects in development, with 27% having completed an advanced feasibility study, and a further 15% (comprising gold, iron ore and lithium projects) already committed.

Figure 4: Project pipeline for key minerals, WA



Source: Department of Industry, Science and Resources

While some of these projects may aim for low or zero greenhouse gas emissions, others could drive increased gas demand. In particular, growing metals and minerals production could increase mine site electricity use – potentially supplied by gas – especially as declining ore grades (notably in iron ore) raise processing energy intensity. The expansion of lithium downstream processing remains uncertain but could add further demand, with several projects aiming to refine spodumene into lithium hydroxide. Additionally, gas-fired electricity generation may replace diesel in some industrial operations.

Unchecked gas demand growth presents multiple risks

While gas demand grows over the GSOO forecast period, supply is expected to decline due to natural reserve depletion, with market risks increasing beyond 2030 as production from existing fields falls. As a result, AEMO projects an increasing gas supply gap from 2030. While additional supply projects could help bridge this gap, their development is subject to uncertainty – delays, cost overruns or project cancellations could accelerate supply constraints before 2030.

The expected increase in WA gas consumption risks locking in higher gas dependency just as supply constraints emerge. In addition, anticipated gas demand growth coupled with tightening supply risks could push prices higher and make gas-intensive industries less viable over time. AEMO noted that WA gas prices have already increased materially in the past few years to about $7 per gigajoule (GJ) on average, and that prices above $8/GJ would start negatively affecting consumer demand. Recent changes to allow domestic gas producers to sell up to 20% of their production into LNG markets (until 2031) will likely increase the link between domestic prices and currently high global LNG prices, leading to domestic price increases.

Growing gas demand is also at odds with domestic and global climate objectives. While Australia's emissions decreased by 29% between 2005 and 2022, WA's emissions increased by 8% – with strong increases in fuel combustion and fugitive emissions only partially offset by decreases in land-based emissions. In its Paris-aligned scenarios, the International Energy Agency expects global gas demand should start declining now to achieve a 40% to 80% reduction by 2050. A much faster decline is required for developed economies. Australia's emissions projections also show that achieving the country's emissions reduction target of 43% below 2005 levels relies on a continuous decline in stationary energy emissions, including in the manufacturing and mining sectors.

An over-reliance on gas could also risk Australia's competitiveness in emerging green markets such as green iron and steel. Globally, countries chasing a share in the green iron and steel market are focusing on green hydrogen-based production, rather than gas-based production. Customers willing to pay a premium for low-carbon iron and steel are already buying green steel made using green hydrogen. There is a significant risk that steel produced using gas won't meet future definitions of what constitutes "green iron" and "green steel".

Many options to decrease gas use in the near term

Liquefied natural gas

WA accounted for 12% of global LNG exports in 2023, and remains the largest LNG exporter in Australia, making up 60% of the nation's total. There are five active LNG export projects in WA, with most onshore processing in the Pilbara region. The North-West Shelf, Pluto, Gorgon and Wheatstone projects source gas from the Carnarvon Basin, while the Prelude project operates as a floating LNG facility in the offshore Browse Basin.

Significant amounts of gas are consumed as a fuel for refrigeration compressors and power generation during the liquefaction of gas. Roughly 0.10GJ of additional gas are needed for each gigajoule of LNG produced, meaning 10% of the gas flowing through a facility is consumed rather than sold as LNG. Finding an alternative energy source for LNG processing would free up 229PJ of gas based on 2024 consumption, equivalent to that used in WA's entire mining and minerals processing sectors, provided the gas is directed to the domestic market instead of it being exported.

Electric turbines have long been known to offer potential advantages for gas liquefaction, including reduced emissions, increased efficiency and lower maintenance costs. While gas turbines have remained the default choice due to historically lower capital costs and simpler integration, examples such as the Freeport eLNG facility in the US demonstrate the viability of all-electric LNG plants. By replacing gas turbines with electric motors, Freeport has achieved more than 90% lower liquefaction emissions using grid electricity, along with operational benefits such as a 6.5% production increase, greater flexibility and reduced maintenance costs.

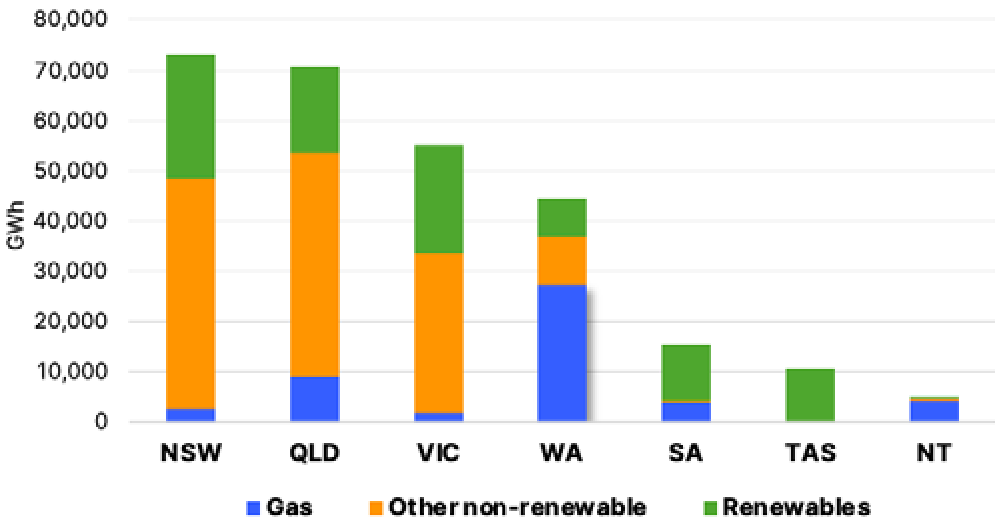
Despite these benefits and technological maturity, there are no announced plans to deploy electric turbines in Australia's LNG plants. While electrification is occasionally mentioned in company sustainability reports, there is typically no clear timeline or commitment. This is indicative of an industry that has historically prioritised reliability and uptime over gas use efficiency, given an abundant supply of low-cost gas. The absence of strong regulatory or policy incentives to reduce gas consumption has also contributed to this inaction. Furthermore, electricity access is constrained in the regions where LNG plants are located. However, some Australian LNG producers face constraints on emissions, throughput, efficiency and reliability that may drive greater attention on opportunities to reduce gas intensity in the future.

While not included in gas consumption statistics, another opportunity to reduce gas use would be to capture fugitive methane (essentially fossil gas), which leaks from gas production and transportation systems. IEEFA previously calculated that about 27PJ of methane could be captured across Australian oil and gas sector, corresponding to a lost value of about $200 million on the domestic market. This methane could be recovered through the implementation of best-practice equipment and processes, at a net financial benefit for companies.

Electricity generation

About a quarter of WA's gas is used for electricity generation, with 14% supplying grid-connected networks and 10% directly powering mine sites. Gas plays a much larger role in WA's electricity generation than in other states (Figure 5), with more gas used for power generation in WA than in the rest of Australia combined. WA is the only state or territory with no renewable energy target, and has fallen behind other states on the transition to renewables. Electricity generation in WA from large-scale solar and wind stagnated between 2021 and 23 while it increased by 33% in the eastern states.

Figure 5: Electricity generation by source and state (includes off-grid), 2022-23



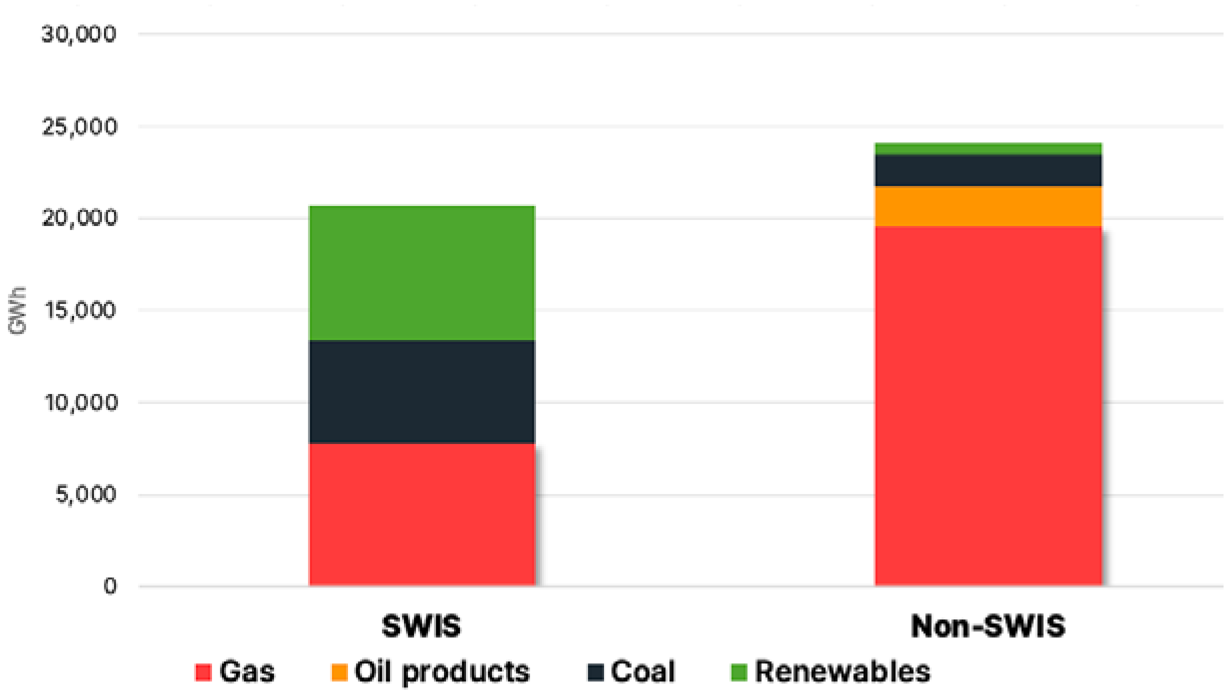
Source: DCCEEW, Australian Energy Statistics 2024, Table O.

WA's electricity system operates separately from the National Electricity Market (NEM), with two major grids and numerous off-grid systems. The South West Interconnected System (SWIS), supplies most of the state's population, while the North West Interconnected System (NWIS) consists of separately owned but interconnected networks serving the Pilbara. Gas is used in both grids for baseload generation and peaking capacity.

In addition to these grids, there are also many off-grid facilities throughout the state. Several gas-fired power stations across the Pilbara, Goldfields and other resource regions supply electricity directly to mining operations, supporting major iron ore, gold and nickel projects. As of early 2022, 10 WA mines had started sourcing electricity from renewables, but progress is very limited at this stage, with renewables representing only 2.6% of generation outside the SWIS. This is despite the Pilbara being considered to have some of the world's best renewable energy resources.

Three quarters of WA's gas-based electricity generation – about 20 terawatt hours (TWh) – occurs in the NWIS and in off-grid systems, where gas comprises 82% of the generation mix (Figure 6). In the SWIS, gas accounts for a third of annual electricity generation.

Figure 6: WA's electricity generation mix FY2023, SWIS vs non-SWIS



Sources: IEEFA analysis comparing FY2023 SWIS generation from Open Electricity and FY2023 WA generation from Australian Energy Statistics, Table O.

The share of renewables in the SWIS is projected to rise rapidly from 38% in 2025 to 81% by 2030. This mirrors modelling undertaken by the WA government in 2023, where renewables were expected to produce 80% of SWIS electricity by 2030 and 96% by 2042.

According to the GSOO, gas is anticipated to play a complementary role managing "extended periods of low VRE [variable renewable energy] generation and providing firming support when other dispatchable sources are unavailable". The forecast amount of gas consumed in the SWIS is broadly stable through to 2034. However, the share of gas-based electricity in the SWIS declines to 18% by 2034 as overall generation increases materially. In the eastern states, the share of gas generation is expected to drop to less than 3% by 2034 to play a similar firming role, suggesting there are opportunities to further reduce gas generation in WA as well. In particular, batteries are expected to be price-competitive and capture an increasing share of daily evening peaks, focusing the role of gas on infrequent, extended low-renewables periods.

Unlike the SWIS, there is a lack of publicly available modelling on the electricity supply outlook in non-SWIS regions, where most of WA's gas-based power generation occurs. A rough outlook can be inferred from the federal government's emissions projections, where emissions from "other grids" (i.e. non-NEM and non-Wholesale Electricity Market) decline by just 18% and 29% to 2030 and 2040 respectively. With WA accounting for most of Australia's emissions from "other grids", this suggests much slower deployment of renewables compared with the SWIS. As with the SWIS, additional electricity demand in remote operations is expected to be met by renewables.

As part of its Pilbara Energy Transition Plan, the WA government has announced the development of priority common use infrastructure corridors in the region to prevent duplications and "enable access to diverse renewable energy sources, support energy security and reliability and reduce the impact of industry on the environment". This could assist onshore processing of critical minerals and strategic metals, positioning Australia to lead in new export opportunities such as green iron, provided it is fuelled by renewable electricity.

Alumina

As of February 2025, there are two companies operating three alumina refineries in WA: Alcoa (Wagerup and Pinjarra) and South32 (Worsley). Alcoa announced the full curtailment of its Kwinana operations in August 2024 due to a variety of operational factors and market conditions. With the Kwinana closure, WA refineries now produce roughly 55% of Australia's annual output.

Alumina represented 17% of WA's total gas use in 2024, and 90% of the gas consumed in the state's minerals processing sector. Alumina refining involves two main stages that represent 95% of energy consumption: the Bayer process, which utilises steam to extract alumina from bauxite using a caustic soda solution; and the calcination process, which requires high temperatures of about 1,000°C to remove water from the final alumina product.

Australia's refineries consumed an average of 11.4GJ energy per tonne of alumina in 2023, with approximately 70% of this energy used in the digestion process and 30% in calcination. While both processes rely predominantly on gas, coal accounted for nearly half of the operational energy at South32's Worsley refinery in FY2024. In 2023, South32 began converting the plant's coal-fired boilers to natural gas in line with company goals to halve greenhouse gas emissions by 2035.

Electrification is the main opportunity to reduce or eliminate gas use in alumina refining, with electric technologies available for both digestion and calcination at varying levels of maturity. Mechanical vapour recompression (MVR) and electric boilers could provide the necessary steam for digestion. An IEEFA report found that the deployment of MVR has the potential to become a financially attractive option even without government subsidies, replacing 5GJ of gas with 1GJ of electricity, and reducing WA's gas use by about 10%. MVR use for alumina refining is in its early stages – Alcoa launched a pilot at Wagerup in 2021, but this was closed in November 2023 due to cost overruns. Despite these challenges, Alcoa believes the technology could play a role in decarbonising alumina but stresses the need for a successful small-scale demonstration before larger-scale deployment.

Electric calcination is at an early stage of development, with the aim to replace fossil fuel combustion with electric heating. The Alcoa Calcination Pilot, supported by the Australian Renewable Energy Agency's (ARENA) Advancing Renewables Program, is trialling electric calciners powered by renewables until 2027. Hydrogen calcination is another option that may be more suitable for retrofit than electric calcination, although operating costs would likely be higher due to the costs of hydrogen supply.

Ammonia

WA's ammonia production is concentrated in the Pilbara and Kwinana regions. The state's largest ammonia producer, Yara Pilbara, operates an integrated ammonia and ammonium nitrate plant near Karratha, primarily supplying mining explosives for the resources sector. In the south, CSBP operates an ammonia plant in Kwinana, which supplies fertilisers to WA's agricultural sector, and ammonium nitrate to mining operations, alongside the production of other industrial chemicals.

Ammonia production in WA is a large consumer of gas, with all facilities relying on steam methane reforming (SMR) to produce hydrogen, which is then combined with nitrogen in the Haber-Bosch process. Gas serves as both a chemical feedstock and an energy source, with approximately 34GJ of gas required per tonne of ammonia. Of this, more than two thirds are typically used as the feedstock for hydrogen production; the remainder is combusted to generate the high-temperature heat required for the process.

As hydrogen is already the key input to ammonia production, green hydrogen can replace SMR-derived hydrogen directly, reducing gas consumption. Up to 30% of the gas used in ammonia production could be replaced with green hydrogen without major equipment upgrades. However, the high cost of green hydrogen remains a major barrier. Many hydrogen projects have struggled as early optimism met economic and technical realities – high capital costs, supply chain constraints and slow policy support – have stalled deployment, prompting a reassessment of cost reductions. BloombergNEF (BNEF) recently revised its hydrogen cost projections, estimating that without subsidies or carbon prices, green hydrogen is unlikely to become competitive with conventional gas-based hydrogen by 2050. This is a stark reversal from previous analysis that anticipated cost parity in some markets by the 2030s.

To help close the cost gap, the Australian government has introduced a $2 per kilogram Hydrogen Production Tax Incentive (HPTI) under its Future Made in Australia package. Costs could be further reduced thanks to the $2 billion Hydrogen Headstart funding for large-scale renewable hydrogen projects. However, a cost premium is likely to remain. WA's ammonia industry has a unique advantage to transition to green hydrogen: a large share of production goes into ammonium nitrate for mining explosives, allowing costs to be passed on to mining customers with minimal impact. This built-in demand and cost pass-through potential make ammonia a logical early adopter of green hydrogen, helping scale production and drive broader cost reductions that could position the state as a leading green hydrogen producer globally.

With full gas replacement likely to remain prohibitive for some time, incremental blending of green hydrogen is a possible transition pathway. Combining IEEFA analysis (including the HPTI) with the new BNEF cost forecasts suggests that a 2030 target of replacing 10% of gas feedstock used to produce explosives with green hydrogen would increase mine site costs by just 0.1% (to be conservative, this is based on 2025 production costs). By 2035, a 30% target would raise costs by 0.2%. If adopted across WA's ammonia plants and potential new projects, this could displace up to 5PJ of future gas demand.

Iron and steel

Steelmakers around the world are exploring opportunities to reduce greenhouse gas emissions in response to growing investor pressure and developments such as the EU's Carbon Border Adjustment Mechanism. For most producers, this will involve transitioning away from conventional integrated steelmaking processes that use iron ore in blast furnaces, which produce 71% of global crude steel – and 73% in Australia. One of the most promising alternatives is direct reduced iron (DRI), which enables lower-carbon steel production by using gas or hydrogen instead of coal as a reducing agent.

DRI is already a proven process with 136 million tonnes produced in 2023, primarily in India, the Middle East and North Africa. About two thirds of global DRI production uses gas-based processes, while the remainder is produced with coal-based rotary kiln technology – mostly in India. While green hydrogen is not yet used at scale, technologies are already available and being deployed from major equipment providers that allow flexibility on the amount of gas and green hydrogen used in the production process.

There is growing interest in leveraging Australia's excellent iron ore and renewable energy resources to produce "green iron" onshore for export to steelmakers seeking emissions reductions. The WA government has released its Renewable Hydrogen Strategy, which highlights green iron as a particularly attractive opportunity, and outlines potential types of support for strategically important projects. However, the two main WA projects proposed by POSCO (hot briquetted iron (HBI)- a premium form of DRI for transport) and Green Steel WA (DRI) would only produce a combined 4.5 million tonnes, far from the scale needed to position Australia as a major player in the future green iron market.

Moreover, with cost-competitive green hydrogen supply potentially decades away, most so-called "green iron" projects intend to rely on gas initially, with plans to transition to green hydrogen either absent or low in ambition. Although cleaner than blast furnace-based steelmaking, gas-based DRI is not a low-emissions solution. For example, POSCO's proposed plant in Port Hedland would produce 0.70 tonnes of carbon dioxide equivalent (tCO_2e) per tonne of HBI. In addition, a new report has found that WA will not be cost-competitive globally for the production of gas-based DRI, with costs about 20% higher than the Middle East, Canada and the US by 2030. It found that Australia's competitive advantage lies in green hydrogen-based production.

Commencing gas-based DRI production in WA without a clear transition plan to hydrogen risks locking in large amounts of gas demand that could exacerbate risks of a gas supply gap. Although both of the proposed WA green iron projects discussed earlier intend to transition to green hydrogen, the POSCO project only proposes a 10% blend in 2033-38 and a 30% blend in 2039-42, while Green Steel WA has not provided further detail. If these projects targeted a 10% gas substitution in the short term, this would free up roughly 5PJ of future gas demand while providing much-needed offtake certainty for Australia's potential green hydrogen producers.

Stronger incentives and support urgently needed

As outlined in this report, there are many untapped opportunities to reduce future gas demand in WA. A focus on demand-side measures can mitigate the risk of worsening gas market tightness, support industrial competitiveness and contribute to national emissions targets – while positioning WA as a leader in the global energy transition. To this end, IEEFA recommends consideration of the following targeted actions:

1. Develop a clear roadmap for gas demand reduction

- Establish a WA gas substitution or decarbonisation roadmap, following the example of Victoria and New South Wales, including clear targets for gas demand reduction.
- Align industry and government funding programs, ensuring electrification and alternative fuels are prioritised in programs such as ARENA's Advancing Renewables and Future Made in Australia.

2. Limit the impact of new projects on gas demand

- Mandate renewable energy adoption in new mining projects to minimise fossil fuel reliance for electricity supply.
- Require immediate green hydrogen use in new "green iron" and ammonia projects, implementing blending mandates that move to 100% adoption over time.

3. Accelerate gas demand reduction in existing facilities

- Support electrification of gas-intensive industries, such as LNG processing and alumina refining, through targeted trials, funding and other financial incentives.
- Accelerate the transition to renewable electricity generation and batteries, particularly in the North West Interconnected System and off-grid industrial sites.
- Introduce progressive offtake requirements for green hydrogen-based explosives, ensuring a phased transition in mining operations while minimising cost impacts.

About IEEFA

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

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