Climate Resource



Phasing out Australia's fossil fuel industry

What 1.5°C pathways mean for Australia's coal, gas and oil

Dr Anita Talberg, Karla Spiller, Rebecca Burdon

November 2026

This report was commissioned by WWF-Australia.

Suggested citation

Talberg A., Spiller K., Burdon R. (2026). Phasing out Australia's fossil fuel industry: what 1.5°C pathways mean for Australia's coal, gas and oil. Climate Resource, Melbourne, November 2026.

Authors

Dr Anita Talberg, Karla Spiller, Rebecca Burdon

Climate Resource acknowledges the Traditional Owners of Country throughout Australia and recognises their continuing connection to land, waters and culture. We pay our respects to their Elders past and present.

Acknowledgements

This report has benefited significantly from insights, ongoing dialogue and/or peer review with numerous experts. In particular, we would like to express our sincere gratitude to Andrew Gorringe and Jonathan Teubner for their guidance in shaping the some of the framing, methodology, and/or analysis of this work. We are also grateful to them and others as external peer reviewers, generously providing their time and expertise to review the draft and strengthen the final report.

Get in touch

Climate Resource provides climate-science modelling, emissions data and scenario analysis to support decision-makers in navigating the transition to a net-zero world, and responding to the changing climate. We're always open for new engagements and would welcome the opportunity to collaborate with your team. Please contact us to discuss how we can support your climate-risk and transition-analysis needs: www.climate-resource.com

Disclaimer

Neither Climate Resource Pty Ltd (ABN: 86 641 266 686) nor its directors or employees make any representation or warranty as to the accuracy or completeness of this report. Nor shall they have any liability, whether arising from negligence or otherwise, for any representations (express or implied) or information contained in, or for any omissions from, the report or any written or oral communications transmitted in the course of preparing and delivering this report.

Image credit

Cover photo: Coffin bay National Park, South Australia, 2026, Karla Spiller

Copyright

Copyright Climate Resource Pty Ltd. All rights reserved. Climate Resource Pty Ltd is not liable for any loss caused by reliance on this document.

Executive summary

The global energy system is being reshaped by cheaper clean energy and by the commitments countries have made under international climate law. On the pathways that meet those commitments, the shift to electrification backed by renewables speeds up sharply over the next decade. Australia, with some of the world's best renewable resources, is well placed to prosper in that world, and a planned transition away from fossil fuels is part of getting there.

Australia has committed internationally to transition away from fossil fuels, but not to a timeline for doing so. This report asks when Australia's fossil fuel industry phases out if the world follows the most ambitious 1.5°C pathways still achievable. It brings together demand for Australia's coal and liquefied natural gas (LNG) exports, and Australia's own use of coal, gas and oil. By phase-out we mean the point at which use and exports have fallen to a residual too small to sustain the industry in anything like its current shape.

The timelines

Under the lowest-overshoot pathways, which peak at around 1.7°C and return towards 1.5°C by 2100, the industry as a whole shrinks fast. In 2024 it handled about 19.7 EJ of energy, almost three-quarters of it exported, and by 2050 that falls to about 5%. Each fuel leaves over a span of exit years, from an 80% decline in its use and exports to a 95% decline: thermal coal from 2034 to 2039, metallurgical coal from 2042 to 2050, gas from 2037 to 2049 (with LNG exports gone by 2042) and oil from 2050 to 2067 (Figure ES).

Coal is almost all exports, so its customers set its exit years. Gas's exit years start as existing LNG contracts run out and end seven years later, when use and exports together are 95% below 2024 and domestic use is still about a quarter of today's. Oil is domestic demand only.

These exit years are not forecasts or targets. They show what Australia would face if the world followed a least-cost route to 1.5°C. The global models behind them find the cheapest way to meet the goal. They do not decide which countries should move first, or who should pay, given differences in responsibility and capacity. The findings are one input into that conversation, rather than the answer to it.

Why test 1.5°C

When the Paris Agreement was adopted, projected warming this century was 3–3.5°C. Today it is about 2.8°C under current policies, falling to about 1.9°C if every national target and net-zero pledge is met. That is still higher than what countries have committed to under international law. Australia's own target has moved from a 26–28% cut by 2030 to 62–70% by 2035. The global goals Australia has backed (tripling renewables, doubling energy efficiency, and the proposed 35-by-35 electrification pledge) are anchored on 1.5°C, and all of them imply falling fossil fuel use. Assets that take decades to pay back, and the regions that depend on them, are better prepared if the transition is planned against the most ambitious plausible pathway, not only the central case. The same logic sits behind central bank climate stress tests and Australia's mandatory climate reporting, which requires large companies to test their strategy against a 1.5°C scenario.

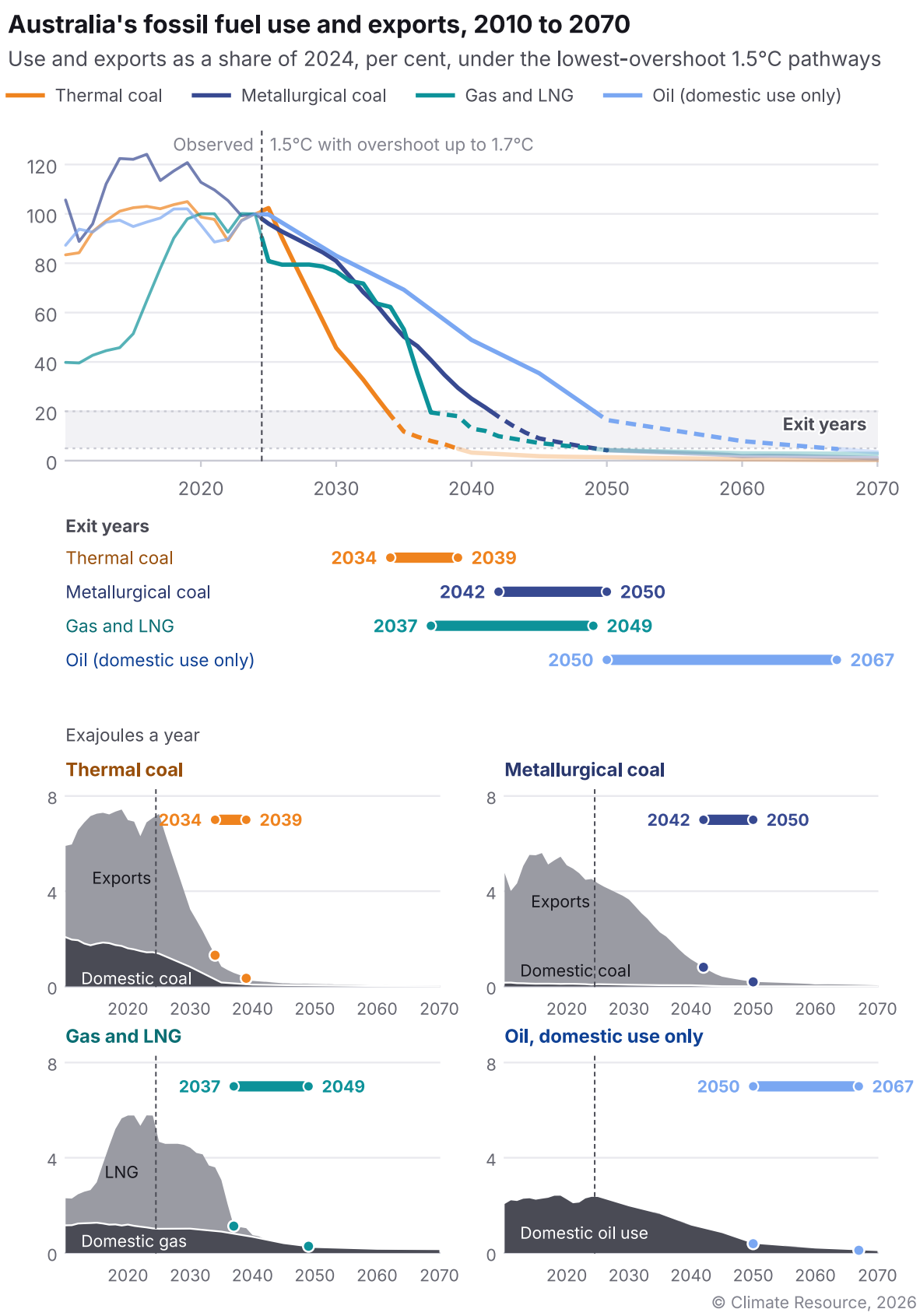


Figure ES: Australia's fossil fuel use and exports, 2010 to 2070: domestic use and exports together as a share of 2024 (top) and by fuel (below), with each fuel's exit years marked.

Key findings

1. Australia's transition risk depends not on how much fossil fuel the world uses, but on how quickly demand for Australian coal and gas declines. Most assessments assume changes in global demand flow straight through to Australian exports. This report instead asks how much demand is actually available to Australian exporters:

- **LNG:** only about 3% of global gas demand consistent with the lowest-overshoot pathways is not already met by domestic production, pipelines or signed contracts. Globally, liquefaction capacity dwarfs uncontracted LNG demand out to 2050.
- **Coal:** China and India mine most of what they burn, so as their demand falls, imports go first.

Earlier work answers narrower questions. Domestic studies treat exports as an input or leave them out. Treasury takes export demand as an input from a less ambitious, well-below-2°C scenario, and the Future Gas Strategy models LNG only, with exports continuing after today's contracts end. The closest study, Climate Analytics' 2026 phase-out analysis, uses a single model and holds Australia's share of each customer's fossil fuel use fixed. The exit dates here are earlier than the Australian Government's for two reasons. These are based on a more ambitious pathway and the trade lens. Against Climate Analytics, whose pathway is as ambitious, LNG ends earlier here and metallurgical coal later.

2. By 2035 the coal industry is just over a quarter of its current size. Coal exports fall from 362 Mt in 2024 to about 100 Mt in 2035, most of what remains is metallurgical coal from Queensland. Thermal coal's exit years are 2034 to 2039, with domestic use a year or two behind exports. Australia's announced coal power closures are already too slow for this. About 5.5 GW, a quarter of today's capacity, is due to keep running past 2040, around when domestic thermal coal use falls below 5% of today's level on the median pathway. Metallurgical coal lasts longer, because steelmaking decarbonises later and Australia's low-ash coal is hard to replace. Its exit years are 2042 to 2050. The Hunter is hit on both fronts as its export customers and its three large power stations go in the same decade.

3. LNG is capped by the contracts already signed. Because the market is oversupplied, Australia's existing LNG contracts are effectively the ceiling on its exports in these scenarios. Deliveries fall steeply between 2035 and 2037 as the Northern Territory's and Queensland's contracts end. They reach zero in 2042, when Gorgon's last contracts expire. A warmer pathway leaves more uncontracted demand, but not enough to need new Australian supply.

4. Australia's own use of gas and oil goes last. Gas's exit years run from 2037, when existing LNG contracts have almost run out, to 2049, seven years after the last contracts end. Domestic use is then still about a quarter of today's level and falls below 20%, where the gas networks stop being viable, in 2056. Once east coast LNG contracts end, by 2036, domestic gas has to stand on its own. That raises questions about prices, who pays for infrastructure built for export, and reservation policies that rely on exports. Oil's exit years are 2050 to 2067. More than 90% of Australia's liquid fuel is imported, so the oil phase-out is about demand and fuel security rather than production.

5. The end could come sooner. Coal leaves Australia through shared mine, rail and port systems, and east coast gas through fields and pipelines sized for export. As volumes fall, fixed costs are spread over less coal and gas, and a system can stop paying its way before

its last customer has gone. New South Wales and northern Queensland, where most of the coal shipped is thermal, would face that test first.

What this means

Falling fossil fuel demand is one side of a transition that also opens large opportunities for Australia. The question is whether the decline is planned as deliberately as those opportunities are pursued.

First, the end could come sooner than these years suggest, which makes a strong case for planning. A coal consolidation and closure plan, agreed with industry, unions and communities, would sequence the decline around workers, regions and shared infrastructure. Without one, the timing is left to closure notices, and to pressure for public bail-outs of mines, ports, pipelines and suppliers once the decline is under way. A bail-out at that point would be a failure of planning, not a response to a surprise.

Second, the window to benefit is short, and there is little room for new supply. Most of the coal and LNG Australia will export is shipped before 2040. In every year modelled, global liquefaction capacity far exceeds the LNG demand still to be contracted, so new or expanded Australian LNG would be built for a market that is not there. Coal demand falls far faster than existing mines can supply it, so the same holds for new coal mines. The one caveat is that this analysis does not test, mine by mine, whether some new metallurgical coal output may be needed to replace mines that run down. How the resource is taxed from now, and whether new supply is approved, will determine how much Australia gains before the industry phases out.

Third, the replacement must match the scale of what is lost. Fossil fuel exports earned $149 billion in 2024–25, mostly in a few regions. A phase-out plan requires a phase-in plan.

Fourth, domestic energy plans should be tested against these dates. Exporters and domestic users share the same gas fields, pipelines, and coal mines, so as exports fall, the cost of supplying Australian users rises. The east coast gas market is the place to start as the Queensland LNG contracts that underpin its fields and pipelines end by 2036.

These dates show what Australia would face in a 1.5°C world, and how little time there is to prepare.

Table of contents

Executive summary **3**
The timelines 3
Why test 1.5°C 3
Key findings 5
What this means 6
Background and context **11**
Australia's commitments and obligations 11
Planning for an orderly transition 12
Australia's fossil fuel industry is particularly important and exposed 13
Building on existing analysis 16
The latest 1.5°C pathways **18**
What does 1.5°C imply for Australia's coal industry? **21**
Australia's thermal coal industry exits between 2034 and 2039 23
Australia's metallurgical coal industry exits between 2042 and 2050 28
Australian coal in 2035: an industry reshaped 31
What does 1.5°C imply for Australia's gas industry? **40**
Australian LNG contracts reach zero in 2042 42
Australian gas and LNG exit between 2037 and 2049 50
Australia's gas industry looks different after 2035 53
What does 1.5°C imply for Australian oil use? **57**
Oil use exits between 2050 and 2067 as electricity replaces it 58
The outlook for the Australian fossil fuel industry **61**
Conclusions **65**
References **66**
Appendices **73**
A1 - Scenarios and demand pathways 73
A2 - LNG methodology 74
A3 - Publicly disclosed changes to LNG supply contracts, January to October 2026 75
A4 - Coal methodology 79
A5 - Coal export system mapping 80
A6 - Oil methodology 81
A7 - Comparison with other assessments 82
A8 - Data centres and electricity demand 82

List of tables:

Table 1: Thermal coal exports: years below given shares of the 2024 level 255
Table 2: Metallurgical coal exports: years below given shares of the 2024 level 300
Table 3: Australia's coal regions today and in 2035 under the 1.5°C pathway..... 344
Table 4: What forecasters, regulators and network owners expect as domestic gas use falls 533
Table 5: Australia's three gas markets today and after their LNG contracts end..... 555
Table 6: Each fuel's exit years and what happens in them 622
Table A3-1: Publicly disclosed changes to LNG supply contracts, January to October 2026..... 777

List of boxes:

Box 1: Exit years 20
Box 2: Planning for coal consolidation and closure 39
Box 3: The shrinking window of LNG revenue..... 56

List of figures:

Figure 1: Australia's fossil fuel economy 14
Figure 2: Australia's oil: imported fuel, exported crude 15
Figure 3: Global primary energy from gas, oil and coal, 2015 to 2050..... 19
Figure 4: Australian coal flows by producing state and destination, FY2024–25..... 21
Figure 5: Thermal coal demand in Australia's six main markets 233
Figure 6: Australia's thermal coal exports by destination, 2018 to 2050 244
Figure 7: Australian thermal coal use: history and pathways to 2100 266
Figure 8: When Australia's coal power stations are due to close..... 277
Figure 9: Metallurgical coal demand in Australia's nine main markets..... 288
Figure 10: Australia's metallurgical coal exports by destination, 2018 to 2050 300
Figure 11: Australian metallurgical coal use: history and pathways to 2100 311
Figure 12: Australia's thermal and metallurgical coal exports, 2018 to 2050 322
Figure 13: Australia's coal use and exports, 2018 to 2050 333
Figure 14: Australia's coal mines and export systems..... 355
Figure 15: Australia's five coal export systems..... 366
Figure 16: The five coal export systems in detail..... 377
Figure 17: Regional gas supply and destinations, FY2024–25 411
Figure 18: How global gas demand was met in 2025 422
Figure 19: Global LNG demand, contracted supply and export capacity, 2025 to 2050..... 444
Figure 20: Australian LNG contracts by destination market, 2025 to 2050 455
Figure 21: Gas supply and demand in the twelve largest LNG importers 477
Figure 22: Australian domestic gas use: history and pathways to 2100..... 511
Figure 23: Australia's gas use and LNG exports, 2018 to 2060..... 544
Figure 24: Australia's oil supply, refining and use, FY2024–25 577
Figure 25: Australian primary oil use: history and pathways to 2100 58
Figure 26: Australian fossil oil use by end-use sector, 2025 to 2100 600
Figure 27: Australia's domestic fossil fuel use and coal and LNG exports, 2010 to 2070 .. 611
Figure 28: Australia's fossil fuel export phase-out, 1995 to 2050..... 633
Figure A3-1: Publicly disclosed LNG supply contract changes, January to October 2026 . 766
Figure A8-1: Global data centre electricity consumption, 2020 to 2035 833
Figure A8-2: Global electricity generation pathways and data centres, 2020 to 2035..... 833

Acronyms:

ABS	Australian Bureau of Statistics
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AES	Australian Energy Statistics (DCCEEW)
AI	artificial intelligence
BACI	Base pour l'Analyse du Commerce International (CEPII trade database)
bcm	billion cubic metres
BPS	Badan Pusat Statistik (Statistics Indonesia)
CCA	Climate Change Authority
CCS	carbon capture and storage
CEPA	Cambridge Economic Policy Associates
CEPII	Centre d'Études Prospectives et d'Informations Internationales
CMIP7	Coupled Model Intercomparison Project, Phase 7
COP	Conference of the Parties to the UN Framework Convention on Climate Change
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DES	delivered ex ship
DISR	Department of Industry, Science and Resources
EIA	US Energy Information Administration
EJ	exajoule
FGS	Future Gas Strategy
FID	final investment decision
FLNG	floating LNG
GIIGNL	International Group of Liquefied Natural Gas Importers
GJ	gigajoule
GL	gigalitre
GSOO	Gas Statement of Opportunities (AEMO)
GW	gigawatt
IAM	integrated assessment model
IEA	International Energy Agency
IEEFA	Institute for Energy Economics and Financial Analysis
IPCC	Intergovernmental Panel on Climate Change
ISP	Integrated System Plan (AEMO)
JOGMEC	Japan Organization for Metals and Energy Security
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MBtu	million British thermal units
MENR	Ministry of Energy and Natural Resources (Türkiye)
Mt	million tonnes
Mtpa	million tonnes per annum
NDC	nationally determined contribution
NEM	National Electricity Market

NGFS	Network for Greening the Financial System
NRMMRRD	Queensland Department of Natural Resources and Mines, Manufacturing, and Regional and Rural Development
NSW	New South Wales
NZA	Net Zero Australia
OECD	Organisation for Economic Co-operation and Development
PJ	petajoule
PV	photovoltaic
QED	Quarterly Energy Dynamics (AEMO)
SA	South Australia
ScenarioMIP	Scenario Model Intercomparison Project
SPA	sale and purchase agreement
STEPS	Stated Policies Scenario (IEA)
TAFF	Conference on Transitioning Away from Fossil Fuels
TWh	terawatt-hour
US	United States
WA	Western Australia
WEO	World Energy Outlook (IEA)
WOSP	Whole of System Plan (Western Australia)

Background and context

Australia’s commitments and obligations

The first Global Stocktake under the Paris Agreement called on countries to transition away from fossil fuels.[1] Australia signed the Belém Declaration on the Just Transition Away from Fossil Fuels and endorsed the Global Mutirão decision at the 30th Conference of the Parties (COP30), and attended the first Conference on Transitioning Away from Fossil Fuels (TAFF) in Santa Marta in April 2026.[2]

At home, Australia has legislated a 43% cut in emissions below 2005 levels by 2030 and net-zero by 2050.[3] In September 2025, it set a 2035 target of 62–70% below 2005 levels as its third Nationally Determined Contribution.[4] The Net Zero Plan released with that target is backed by six sector plans, and the Electricity and Energy plan names the phase-out of coal power as a priority.[5] The Safeguard Mechanism requires Australia's largest industrial emitters, among them coal mines and liquefied natural gas (LNG) plants, to cut emissions against baselines that fall by 4.9% per year to 2030 and reach net zero by 2050.[6] How fast they fall after 2030 will be set after a review currently underway.[7] The states are moving on coal power at different speeds. Western Australia has committed to closing its state-owned coal plants by 2029. In Victoria, Yallourn is due to close in 2028 and Loy Yang A in 2035, but Loy Yang B is not due to close until 2047. By contrast, Origin has extended Eraring in New South Wales to 2029, and Queensland has dropped its 2035 coal exit and now plans to run its coal plants until at least 2046.[8]

These commitments shape how much coal, gas and oil Australia uses at home. However, they do not determine how long Australia keeps producing fossil fuels. Most of that production is exported, and the emissions from burning it are counted in other countries' inventories, outside the reach of Australia’s 2035 target and the sector plans. That gap is starting to close through the courts. In October 2026, the High Court found that the New South Wales (NSW) Independent Planning Commission should have considered conditions to minimise the overseas emissions from coal mined at Mount Pleasant in the Hunter Valley when it approved the mine's expansion.[9] The Commission had reasoned that those emissions would be accounted for under the Paris Agreement in the countries that burn the coal. The expansion would run to 2048 at up to 21 Mt a year.[10] Hunter Valley Operations, approved in September 2026 on condition that its coal goes only to countries with emissions-reduction policies, runs to 2045.[11] On the 1.5°C pathways in this report, those same customers need almost no Australian thermal coal by 2040. Considering when demand for

[1] UNFCCC (2023), para. 28(d).

[2] Government of Colombia (2025); UNFCCC (2025); Governments of Colombia and the Netherlands (2026).

[3] Parliament of Australia (2022), s 10.

[4] Australian Government (2025).

[5] DCCEEW (2025b, 2025c).

[6] DCCEEW (2025b, 2025c).

[7] DCCEEW (2026a).

[8] Origin Energy (2026); Queensland Government (2025).

[9] High Court of Australia (2026).

[10] NSW Independent Planning Commission (2022).

[11] NSW Independent Planning Commission (2026).

Australian fossil fuels runs out at home and abroad provides a basis for planning an orderly phase-out of the industry rather than reacting to the decline.

Planning for an orderly transition

The temperature goal behind Australia's climate commitments and obligations is the Paris Agreement's, which is to hold warming 'well below 2°C' and to pursue efforts to limit it to 1.5°C.[12] The Global Stocktake called for emission cuts in line with 1.5°C pathways, and for the transition away from fossil fuels to be made in a 'just, orderly and equitable manner'.[13] In 2025, the International Court of Justice advised that 1.5°C has become the primary temperature goal under the Paris Agreement.[14] However, the world's current commitments fall short of this, and planning only to those commitments carries its own risk.

A phase-out date set against today's commitments is a date set on moving ground. When the Paris Agreement was adopted in 2015, projected warming this century was 3–3.5°C. UNEP now puts it at about 2.8°C under current policies, 2.3–2.5°C if national targets are met in full, and about 1.9°C if all net-zero pledges are met as well.[15] Commitments have strengthened within a decade, and may do so again.[16] This is a shift of roughly a full degree in the direction of greater ambition within ten years. Australia's own targets have moved from a 26–28% cut below 2005 levels by 2030 in its first nationally determined contribution (NDC), to 43% by 2030 in 2022, and now 62–70% by 2035.[17]

A target calibrated to today's current policies or commitments risks being overtaken by the next round of commitments before the assets it concerns have reached the end of their planning life. There is no reason to assume that current policies will not be built upon, and strong rationale to assume that they will. Assets that take years to build and decades to pay back, such as LNG trains, coal export terminals, rail and port systems, power stations, pipelines and refineries, face asymmetric risk from mis-timing the transition. Underestimating its pace risks stranded capital, while overestimating it risks forgoing viable returns. Testing a plausible high-ambition pathway, rather than only the central case, is standard practice for this kind of risk. It is the logic behind central bank climate stress tests, and behind Australia's mandatory climate reporting, which requires large companies to test their strategy against a 1.5°C scenario. This report therefore asks:

Under still-plausible, highest-ambition pathways consistent with the Paris Agreement's 1.5°C goal, when do Australia's fossil fuel exports and its use of fossil fuels end, and what does that mean for when its fossil fuel industry phases out?

For exports, the timing is set by the fuel choices of the countries that buy Australian coal and gas, so it arrives whatever target Australia sets. For domestic use, the timing shows how quickly Australia's own coal, gas and oil use would fall if it moved in step with a least-cost

[12] UNFCCC (2015), Art. 2.1(a).
[13] UNFCCC (2023), paras 27–28.
[14] International Court of Justice (2025), para. 224.
[15] Talberg et al. (2026a).
[16] Talberg et al. (2026a).
[17] Australian Government (2015, 2022, 2025).

1.5°C world. Australian policy matters more here, but falling costs for renewables, storage and electric vehicles drive change regardless.

Together, the two give the point by which Australia's fossil fuel industries end in a world that keeps 1.5°C within reach. Phase-out trajectories set with these dates in mind allow an orderly transition, planned around the workers, regions and contracts involved. Setting no date leaves the timing to markets, technology costs and other countries' decisions. That risks a disorderly exit, and with it pressure for public money to prop up mines, ports, pipelines and the businesses that supply them. This report sets out the timing needed to avoid that. With it in view, a bail-out later would be a failure of planning.

Australia's fossil fuel industry is particularly important and exposed

Fossil fuels have shaped modern Australia. Coal has been mined and shipped from Newcastle since the early nineteenth century, and LNG has been exported from the North West Shelf since 1989. In 2024–25 coal, LNG and crude oil, condensate and liquefied petroleum gas (LPG) together earned $149 billion in exports, 39% of the $386 billion Australia earned from resources and energy (Figure 1).[18] LNG brought in $65 billion, metallurgical coal $39 billion, thermal coal $32 billion, and crude oil, condensate and LPG $13 billion.[19]

These exports have underpinned some of Australia's closest international relationships, setting a foundation that can continue as we transition from fossil fuels, to renewable energy-based trade and supply chains. Japan, the largest market, bought $46 billion of Australian fossil fuels in 2024–25, followed by China ($30 billion) and South Korea ($17 billion).[20] For Japan, Australia is the largest supplier of both LNG and coal, and energy trade has been core to the relationship for decades.[21] However, Australia's Pacific neighbours also call for a faster transition away from fossil fuels.[22] Any phase-out is relevant to diplomacy and economics.

Australia's customers are also changing as the 2026 Iran–US war and the closure of the Strait of Hormuz have shown importers how exposed they are to imported fuel, and many now treat reducing that dependence as a security priority. The IEA calls diversifying energy sources 'now a central priority' for Southeast Asia.[23] China and Viet Nam have cancelled LNG projects, and electric car sales have roughly doubled in markets including India, Korea and Viet Nam.[24] Some short-term responses have leaned towards coal, but the longer-run direction seems to be less demand for imported fossil fuels.

The economics also have Australian regional implications. Exports shipped from central Queensland were worth $65 billion in 2024–25, from the north-west coast of Western Australia $48 billion, from the Hunter Valley and Illawarra $27 billion and from Darwin $10

[18] DISR (2026c).
[19] DISR (2026c); DCCEEW (2026d).
[20] DISR (2026c); DCCEEW (2026d).
[21] Ministry of Finance, Japan (2026); S&P Global Commodity Insights (2026); SX Coal (2025).
[22] Governments of Vanuatu et al. (2023).
[23] IEA (2026e).
[24] Hunt (2026); IEA (2026a).

billion.[25] Wages paid by the mining industry were about $2.2 billion in the Hunter and $3.5 billion across the Mackay and Fitzroy regions,[26] and most of the rest goes to shareholders, largely foreign, to suppliers and to state treasuries as royalties.[27]

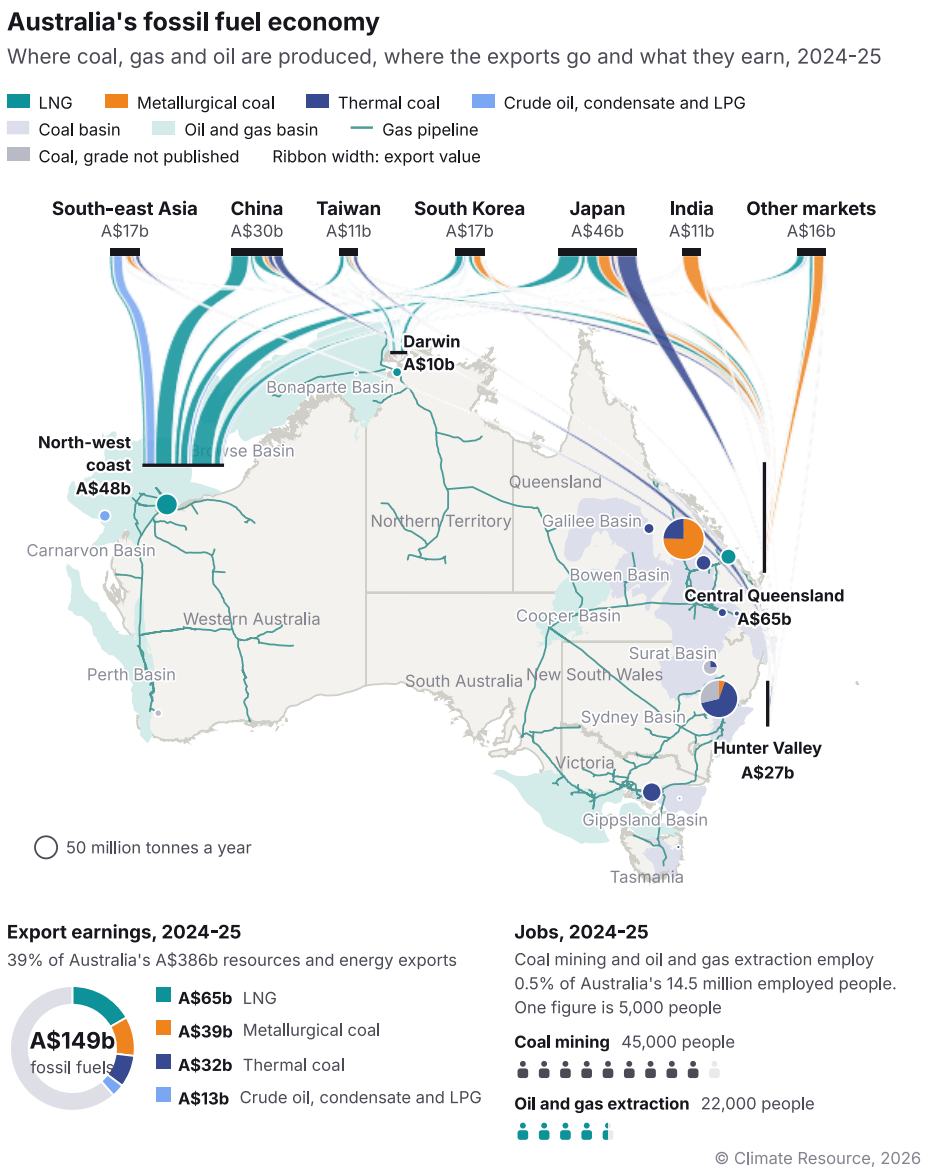


Figure 1: Australia's fossil fuel economy: production, export destinations, earnings and jobs by region. Source: DISR; DCCEEW (2026d); ABS trade data via the Queensland Government Statistician's Office; Global Energy Monitor; Climate Resource analysis.

Nationally, the industry employs around 67,000 people in coal mining and oil and gas extraction, which is just 0.5% of employed Australians but a fifth or more of employed residents in the main coal mining areas.[28] In those regions, new jobs and economic opportunities need to be part of the transition story.

[25] Coal and oil are ABS customs values by state of origin from the Queensland Government Statistician's Office (2026); LNG is from DCCEEW (2026d); totals from DISR (2026c).
[26] NSW Minerals Council (2026); Lawrence Consulting (2025).
[27] Connolly and Orsmond (2011).
[28] DISR (2026c), Table 10; ABS (2022).

The picture for oil is different (Figure 2).

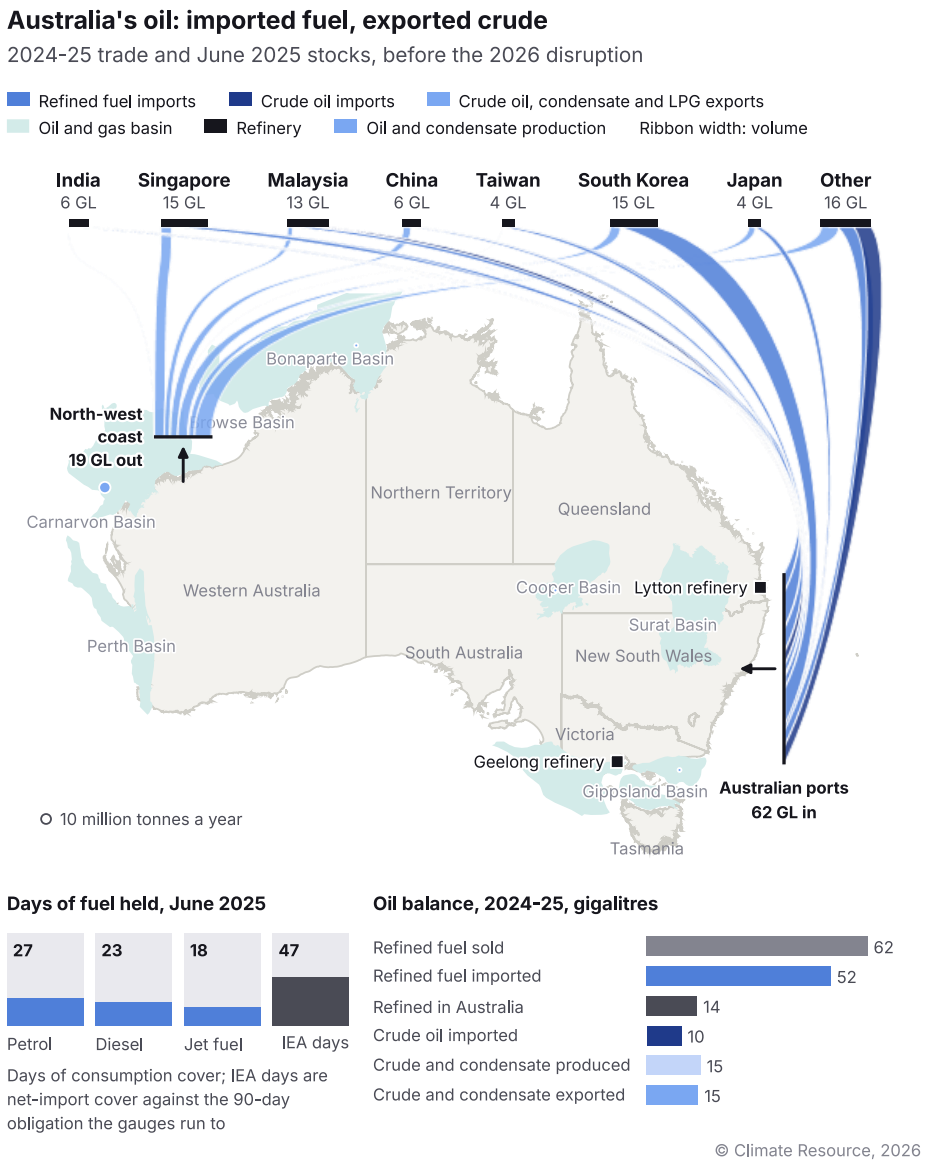


Figure 2: Australia's oil: imported fuel, exported crude. Source: DCCEEW (2026d); Climate Resource analysis.

Australia produces about 15 gigalitres (GL) of crude oil and condensate annually and exports almost all of it, but Australia imports nearly all the fuel it uses. Around 52 of the 62 GL of refined fuel sold in 2024–25 was imported, and most of the rest was refined at Lytton and Geelong from imported crude.[29] Australia is a major fossil fuel exporter and, at the same time, dependent on imported fuel.

Several more features of Australia's fossil fuel industry raise the cost of ignoring these dates:

- **Australian LNG is expensive to produce:** average production-plus-liquefaction cost is the highest among major global exporters.[30] When demand becomes constrained, Australian supply is among the first to be displaced in a price-competitive market.

[29] DCCEEW (2026d).
[30] IEEFA (2024).

- **The industry is concentrated in a few places, and those communities need a plan to prosper in a low carbon world:** fossil fuel export revenue comes from a small number of single-industry regions rather than a diversified economy. The regions that earn most from exports also host the coal power stations that supply the domestic grid. That's the Hunter Valley, central Queensland and Collie, along with the Latrobe Valley, which does not export.
- **Exporters and domestic users share some supply chains:** about 30% of the gas burned in Australia is burned by the LNG plants themselves.[31] Queensland's LNG plants draw on the same Surat–Bowen fields and pipeline network that supply the east coast market, and Western Australia's domestic gas comes largely from LNG projects under the state's reservation policy. Hunter Valley mines supply both export terminals and the state's power stations. A change in one market changes the volumes, costs and viability of supply for the other.
- **Australia depends on imported liquid fuels:** about 83% of the refined fuel sold in 2024–25 was imported directly and about 80% of the crude run through Lytton and Geelong was imported, so more than 90% of Australia's liquid fuel came from abroad (Figure 2).[32] In August 2026, the country held about 52 days of net imports, against the International Energy Agency's (IEA) 90-day obligation, and has fallen short of it for over a decade.[33] The 2026 disruption in the Strait of Hormuz has shown what that dependence costs, and how much a faster shift away from oil would reduce it.
- **Australia has signed up to transition away from fossil fuels, what it needs now is a plan:** one that sets out how and when the transition happens, supports the communities most exposed, and captures the opportunities of a low-carbon world. The window for an orderly transition is narrow.

Building on existing analysis

A body of modelling already informs Australia's energy transition. The Australian Energy Market Operator's (AEMO) Integrated System Plan (ISP) maps how the National Electricity Market moves from coal to renewables.[34] AEMO's Gas Statement of Opportunities (GSOO) tracks whether east coast gas supply will meet demand.[35] Western Australia's Whole of System Plan (WOSP) does the same for that state's main grid.[36] The Commonwealth Scientific and Industrial Research Organisation's (CSIRO's) scenarios for the Climate Change Authority (CCA), the Net Zero Australia (NZA) study and the Department of Climate Change, Energy, the Environment and Water's (DCCEEW) annual emissions projections set out pathways for domestic energy use under a range of policy and climate assumptions.[37] For exports, the Future Gas Strategy (FGS) and the Department of Industry, Science and Resources' (DISR) Resources and Energy

[31] DCCEEW (2026c), pp. 9–10.
[32] DCCEEW (2026d).
[33] Laidlaw (2020); DCCEEW (2026d).
[34] AEMO (2026b).
[35] AEMO (2026a).
[36] Energy Transformation Taskforce (2020).
[37] CSIRO (2025); Net Zero Australia (2025); DCCEEW (2025a).

Quarterly give the government's outlook for LNG and coal.[38] Treasury's Net Zero Transformation modelling sets both within an economy-wide view.[39]

Each of these answers a narrower question than this report asks. The domestic studies treat exports as an input or leave them out completely. The Resources and Energy Quarterly looks five years ahead, on a central case. Treasury takes export demand as an input, from an IEA scenario less ambitious than 1.5°C for coal and from the FGS for LNG. The FGS models LNG trade under three IEA scenarios and has Australia still exporting in 2050 in each, well after today's contracts end. This report asks instead how much importers meet demand from their own production or other cost-effective sources, and how much of any remaining import demand is already contracted and therefore committed. Climate Analytics' 2026 fossil fuel phase-out study comes closest, covering both domestic use and exports under a 1.5°C pathway.[40] However, it draws on a single model, and assumes Australia keeps a constant share of each customer's fossil fuel consumption, so its exports simply track those countries' projected demand.

Climate Resource's own earlier reports examined Australia's coal and LNG export outlooks against a range of peak warming scenarios.[41] This report updates, extends and brings together that work in four ways:

- It uses the latest ScenarioMIP-CMIP7 lowest-overshoot pathways (the Scenario Model Intercomparison Project of the seventh Coupled Model Intercomparison Project), which supersede the Network for Greening the Financial System (NGFS) Phase 5 scenarios used in the previous Climate Resource analysis. It uses the median of ten pathways rather than a single model.
- It updates the asset and contract data with the latest evidence and adds granularity where possible, such as a mine-by-mine production perspective, and terminal- or export-corridor systems.
- It adds Australia's own use of coal, gas and oil, derived from the same pathways and compared with Australian modelling, so that exports and domestic use can be read together.
- It brings coal, gas and oil together in a single analysis of the fossil fuel industry, covering every state and territory rather than only the four that export.

The result is the first set of dates, under the latest 1.5°C pathways, for when Australia's fossil fuel exports, its domestic use, and the industry as a whole phase out.

The report is set out by fuel. The next section describes the 1.5°C pathways and how they are translated to Australia. The chapters on coal, gas and oil then each work through export demand where it applies, Australia's own use, and what the two together mean for the industry. The final sections bring the three fuels together into a single timeline, set out how the impact falls across states and territories, and compare the results with other assessments.

[38] DISR (2024, 2026b).

[39] Treasury (2025).

[40] Houlie et al. (2026).

[41] Burdon et al. (2025); Talberg et al. (2026b).

The latest 1.5°C pathways

The most direct routes to 1.5°C assessed in the Intergovernmental Panel on Climate Change's (IPCC) Sixth Assessment Report, which were known as the ‘C1’ pathways, required global emissions to start falling before 2020. This never happened, and as a result those pathways are no longer achievable on current evidence. The most recent generation of climate scenarios, available from September 2026, rule out a return to 1.5°C without exceeding it.[42]

What remains is a narrower set of pathways that peak above 1.5°C before declining back towards it later in the century. These scenarios are ‘peak-and-return’, or ‘overshoot scenarios’, rather than a straight line. Losing the no-overshoot route does not make 1.5°C irrelevant. It makes how high and how long the world overshoots 1.5°C the numbers that now matter most.

The latest generation of scenario families consists of seven emissions trajectories labelled ‘Very Low’, ‘Low’, ‘Low-to-Negative’, ‘Medium-Low’, ‘Medium’, ‘High-to-Low’, and ‘High’. This report selects scenarios in which global warming peaks at no more than 1.7°C before returning below 1.5°C by 2100. These criteria are met by 10 of the 11 ‘Very Low’ scenarios and no scenarios from other categories. The selected scenarios are used to assess demand for Australia’s fossil fuel exports, the timing of their phase-out, and Australia’s domestic fossil fuel use. The analysis in this report uses the ambitious end of that ‘Very Low’ band to identify when Australia's fossil fuel export sector ends. It is used to assess both the demand for Australia's fossil fuel exports and Australia's own use of fossil fuels.

These pathways come from integrated assessment models (IAMs), the tools that produce many of the scenarios the IPCC draws on in its assessment reports to explore how energy systems, economies and land-use could change to meet a temperature goal. Each model makes assumptions about technology costs, behaviour and policy, so no single model is a forecast. Taken together, they map the range of ways that the world could still reach 1.5°C, and what each implies for coal, gas and oil.

Across the ten pathways used here, global fossil fuel use falls steeply but unevenly (Figure 3). At a global level, coal falls first and fastest, to around 15% of 2025 levels by 2040 and 5% by 2050 on the median. Gas and oil globally decline more slowly, to around 20% and 30% of 2025 levels by 2050, as they hold on longer in industry, heavy transport and aviation. Our companion report sets out these pathways in detail, and Appendix A1 lists the pathways and how they were selected.[43]

[42] Van Vuuren et al. (2026).

[43] Climate Resource (2026).

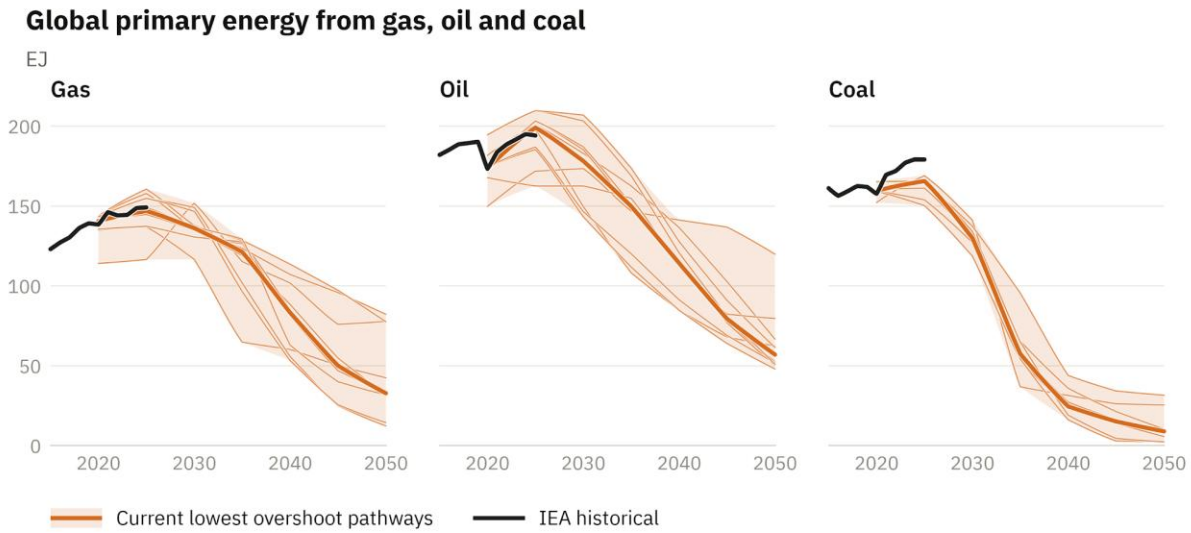


Figure 3: Global primary energy from gas, oil and coal, 2015 to 2050 (EJ per year): lowest-overshoot pathways (median and range) against IEA history to 2025. Source: ScenarioMIP-CMIP7 lowest-overshoot pathways; IEA; Climate Resource analysis.

Modelling this pathway is not a claim that it is the most likely outcome. UNEP projects about 2.8°C of warming this century under current policies, and about 1.9°C even if every national target and net-zero pledge is met.[44] However, these pathways align with the goals that countries have set themselves.

The COP28 decision that called for a transition away from fossil fuels also called for global renewable energy capacity to triple and the average annual rate of energy efficiency improvement to double by 2030, both in line with 1.5°C pathways.[45] The COP31 Presidency added the proposed '35-by-35' electrification pledge, which would mean lifting electricity's share of final energy consumption (the energy used by homes, industry and transport, rather than the energy that feeds power stations) from around 23% today to 35% by 2035.[46]

These global goals describe where the world is trying to head. They are relevant because tripling renewables, doubling efficiency and electrifying a third of final energy are how a fossil fuel phase-out happens. Energy supplied by renewable electricity, or never needed because of efficiency, is energy not supplied by coal, oil or gas. The fossil fuel phase-out therefore falls out of these goals. The fall in demand for Australia's coal and LNG exports follows from falling fossil fuel use in the countries that buy them. The fall in Australia's own use follows from the same shifts at home.

Appendix A1 explains how these global pathways are translated into outlooks for Australia's export markets and for Australia itself. See Box 1, ‘Exit years’, for how to interpret the years used in this report.

[44] UNEP (2025); Talberg et al. (2026a).
[45] UNFCCC (2023), para. 28.
[46] COP31 Presidency (2026); IEA (2026b).

Box 1: Exit years

The exit years:

Each fuel's exit years run from the year its use has fallen 80% to the year it has fallen 95%, under the 1.5°C pathways with overshoot up to 1.7°C. The industry's final phase-out occurs within those years:

- **Why 80% marks the start:** The systems that deliver fuel, pipelines and distribution networks, shared rail and port chains, refineries and service stations, are built for today's volumes, and many of their costs are fixed. At a fifth of design volume, those costs fall on the customers who remain, prices rise, reinvestment stops paying, and the network may consolidate ahead of the volume loss.
    - An example of this for oil: between FY2004 and FY2024, petrol demand in Japan fell from 61.5 to 43.6 billion litres, down 29%. Service-station numbers fell from 48,672 to 27,009, down 45%.[47] By the time oil volumes are at a fifth, the retail network is likely a sparse highway-and-depot service.
- **Why 95% marks the end:** Less than 5% of today's use is left. For coal that may be one mine's output. For gas, a few industrial users on dedicated supply remain. For oil, niche uses such as aviation, mining and chemical feedstock remain. Whatever remains is a residual. It may no longer support shared infrastructure, a workforce of today's shape or the regions that depend on them.
- **What the span tells us:** The years between the two mark how long the last fifth takes to go. A short span (five years for thermal coal) means the system goes almost at once and has to be planned well in advance. A long one (12 years for gas, 17 for oil) means a shrinking system, with uncertainty around how to meet the costs of keeping it. Recognising the length of the exit window as well as the timeframe helps planning. It is the period in which consolidation and closure can be sequenced around workers, regions and shared infrastructure rather than left to closure notices.

For LNG exports, we also highlight a single date. This is the first year with no deliveries under existing contracts, because the outlook for LNG is existing the contracts rather than a demand pathway.

How to read the years:

The exit years are not forecasts or targets.

- Coal's and LNG's are set by export customers and the exit could come on the early side of the range if shared rail and port systems become too costly to run on shrinking volumes, or if LNG plants are not kept supplied to the end of their contracts.
- Oil's are set by domestic consumption. They show how quickly Australia's own use would fall in step with global least-cost pathways, which do not share out effort according to fairness or capacity.
- Gas's are set by both. They begin as existing LNG contracts end and finish as Australian users leave.

Each fuel's exit years, and what happens in them, are set out in Table 6.

[47] Petroleum Association of Japan (2025), Figure 4-9, p. 22, and Figure 4-11, p. 24, drawing on METI and Oil Information Center data. Percentage reductions calculated from the published figures and rounded to the nearest whole percentage point. Service-station counts are measured at fiscal-year end.

What does 1.5°C imply for Australia's coal industry?

Australia produced about 458 million tonnes (Mt) of saleable coal in 2024–25, 419 Mt of it black coal and 39 Mt brown coal, and exported 356 Mt of coal in 2025 (Figure 4). Of that, 209 Mt was thermal coal for power generation, and 147 Mt was metallurgical coal for steelmaking.

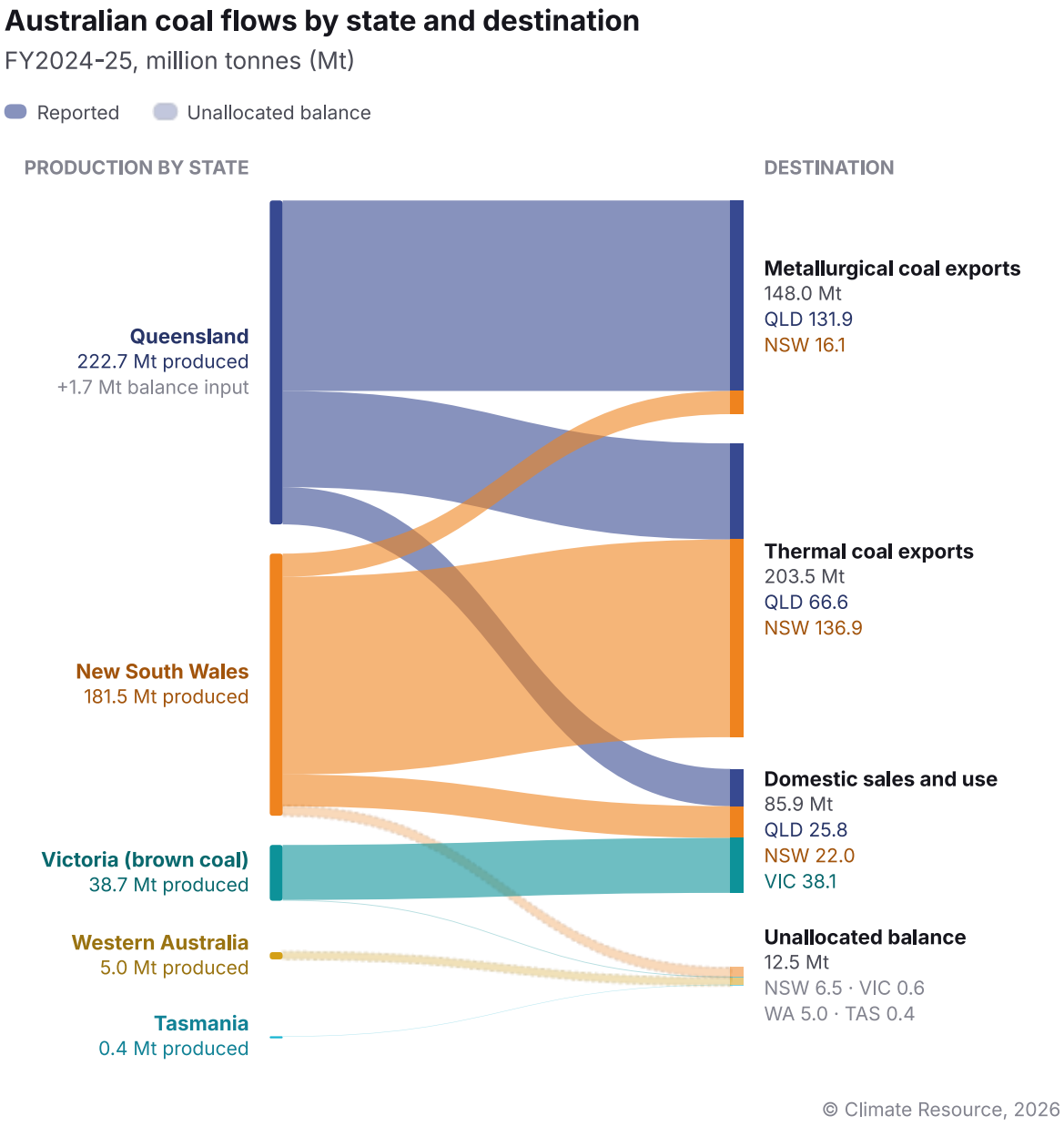


Figure 4: Australian coal flows by producing state and destination, FY2024–25 (Mt). Source: Queensland NRMMRRD; Coal Services; ABS customs data via the Queensland Government Statistician's Office; DCCEEW (2026b).[48]

[48]NSW exports are split by grade with the ABS customs tonnes by state of origin, 2024–25 (10.5% metallurgical). Queensland Government (2026); Coal Services (2025), pp. 37–38; Queensland Government Statistician's Office (2026); DCCEEW (2026b), Table P.

Australia is the world's largest exporter of metallurgical coal, with about 42% of global trade, and the second-largest exporter of thermal coal, after Indonesia.[49] Production is concentrated in two states. Queensland ships about 200 Mt per year, most of it metallurgical coal from the Bowen Basin.[50] New South Wales shipped about 162 Mt in 2025–26, almost all of it thermal coal from the Hunter Valley.[51]

The rest of Australia's coal is consumed domestically, accounting for about 13% of production by energy content.[52] Almost all of this goes to electricity generation.[53] Most domestic coal power is supplied by the same basins that serve the export trade. The exceptions are Victoria's Latrobe Valley and Collie in Western Australia, whose mines supply only local power stations. Metallurgical coal for Australia's steelmaking is about 2% of what is exported. Exports make up most of the industry, so for each type of coal, this chapter looks at exports first and then at domestic use, before bringing the two together to show what the industry looks like in 2035 and what that means for coal-producing regions.

Australian coal exports: a demand-led analysis

The outlook for Australia's coal exports starts with its customers. If the countries that buy Australian coal need less of it, Australian exports fall, regardless of production. The analysis works backwards from demand in each importing country to the share of that demand that Australia can expect to meet:

1. First, we derive future demand in each market. The 1.5°C pathways map the rate at which each importing country's coal use changes under these scenarios. That rate is applied to the country's observed consumption to estimate its future demand.
2. Second, we calculate what each market imports of this projected demand. Countries with their own mines use that coal first. Only the demand left over, after domestic production, is met by imports. This matters for China and India, which produce a lot of the coal they burn. For these two countries, imports are assumed to hold at their 2025 level only while demand exceeds what the country already produces. From the first year that its 2025 production would cover demand, Australia’s exports fall to zero over five years (Appendix A4).
3. Third, we determine Australia's share of those imports. Australia is assumed to keep the share of each market's imports it held over 2022 to 2024, or in 2024 for China and India, where exports start from the calendar-2025 actuals.
4. Finally, we add it all together to derive Australia’s national exports. Smaller markets, that together account for 16% of thermal coal and 25% of metallurgical coal exports, are assumed to follow the same trend.

Holding Australia's share of each market's imports is a simplifying assumption. It could be argued that Australia might gain share as higher-cost exporters leave the market or lose it to cheaper ones. Holding a constant share of the global import market instead results in similar exit years.

[49] IEA (2025a), pp. 71–73; DISR (2026b), pp. 50 and 63; DCCEEW (2026b), Table P.

[50] Queensland Government (2026).

[51] Coal Services (2025), p. 38; NSW Mining (2026); Montoya (2025).

[52] DCCEEW (2026b), Table A.

[53] DCCEEW (2026b), Tables F and P.

Thermal and metallurgical coal are analysed separately because they serve different markets. Thermal coal demand follows the choice of fuel for power generation, and metallurgical coal demand follows the choice of process for steelmaking. However, the two products often share mines, rail lines and ports. In Queensland's Bowen Basin, Dalrymple Bay Coal Terminal ships both thermal and metallurgical coal. The adjacent Hay Point terminal ships only metallurgical coal, but it draws on the same rail corridors and producing region.[54] Rail lines and terminals recover their fixed costs from all the coal that moves through them, so a fall in one product may affect the cost of supplying the other. The chapter focuses on thermal coal first.

Australia’s thermal coal industry exits between 2034 and 2039

Australia's thermal coal exports: demand in a 1.5°C world

Thermal coal is the shorter-lived part of Australia's coal exports, because demand follows power-sector fuel choice, where importers have cost-effective clean energy technology options or domestic mines. Japan, China, Taiwan, South Korea, Vietnam and India together account for around 90% of Australia's 2022–2024 thermal coal exports. Figure 5 shows, for each of these markets, the pathway median and the individual lowest-overshoot pathways of modelled demand, and how that demand splits between domestic production and imports, including the Australian share, to 2050.

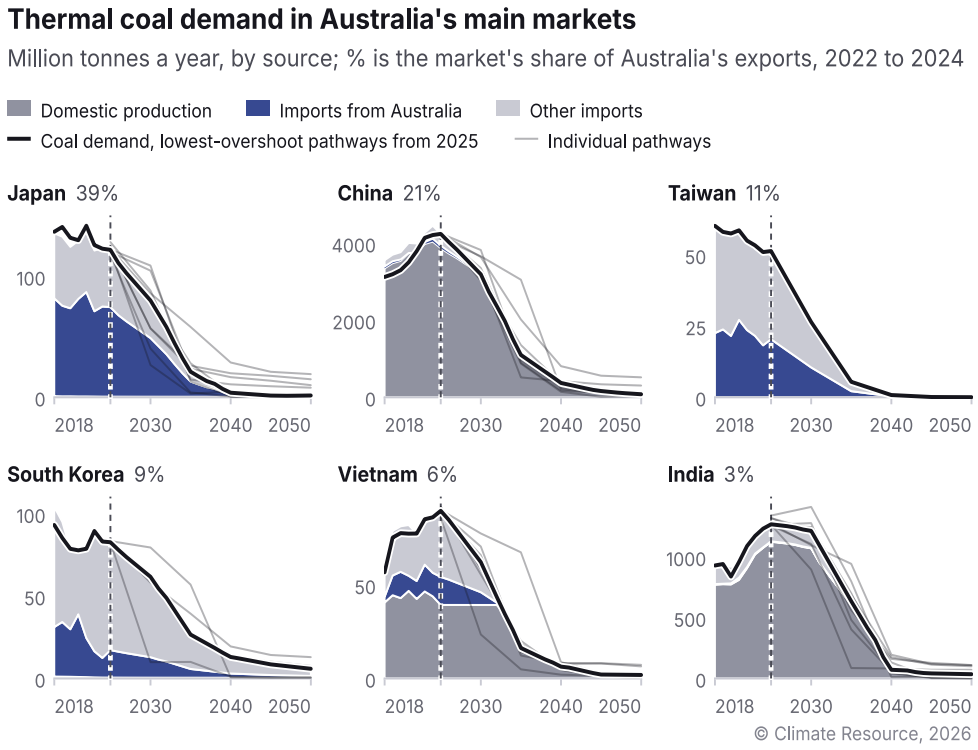


Figure 5: Thermal coal demand in Australia’s six main export markets (Mt per year), by source: domestic production, imports from Australia and other imports, observed to 2024 and the lowest-overshoot median from 2025 (thin lines: individual pathways). Panels have their own scales. Source: DISR; US EIA; IEA; national statistics; ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

[54] Global Energy Monitor (2024); Dalrymple Bay Infrastructure (2026); BHP Mitsubishi Alliance (2026).

Japan, Taiwan and South Korea have little to no domestic thermal coal production, so their import requirement tracks their total consumption directly. As their demand declines under the pathway, so does the market available to Australian exporters, at a broadly similar pace to demand itself.

China and India follow a different pattern because both countries meet the majority of their own consumption from domestic mines. Their coal use is also so large that the Australian share is not even visible in Figure 5. For example, although it represents a substantial share of Australia's thermal coal exports, Australia supplies only 2% of China's total thermal coal consumption. Both India and China may stop importing once their own mines can cover demand. On the median pathway China's thermal coal demand falls below its 2025 production from 2026, so Australia's exports to China hold at the 2025 level, 67 Mt, and then fall to zero over five years, by 2030. India's demand falls below its 2025 production in the early 2030s and its small share of thermal coal imports from Australia is gone by 2036 (Appendix A4). The dip to zero in 2021 in Figure 6 reflects China's restrictions on Australian coal imports, which lasted until early 2023.[55]

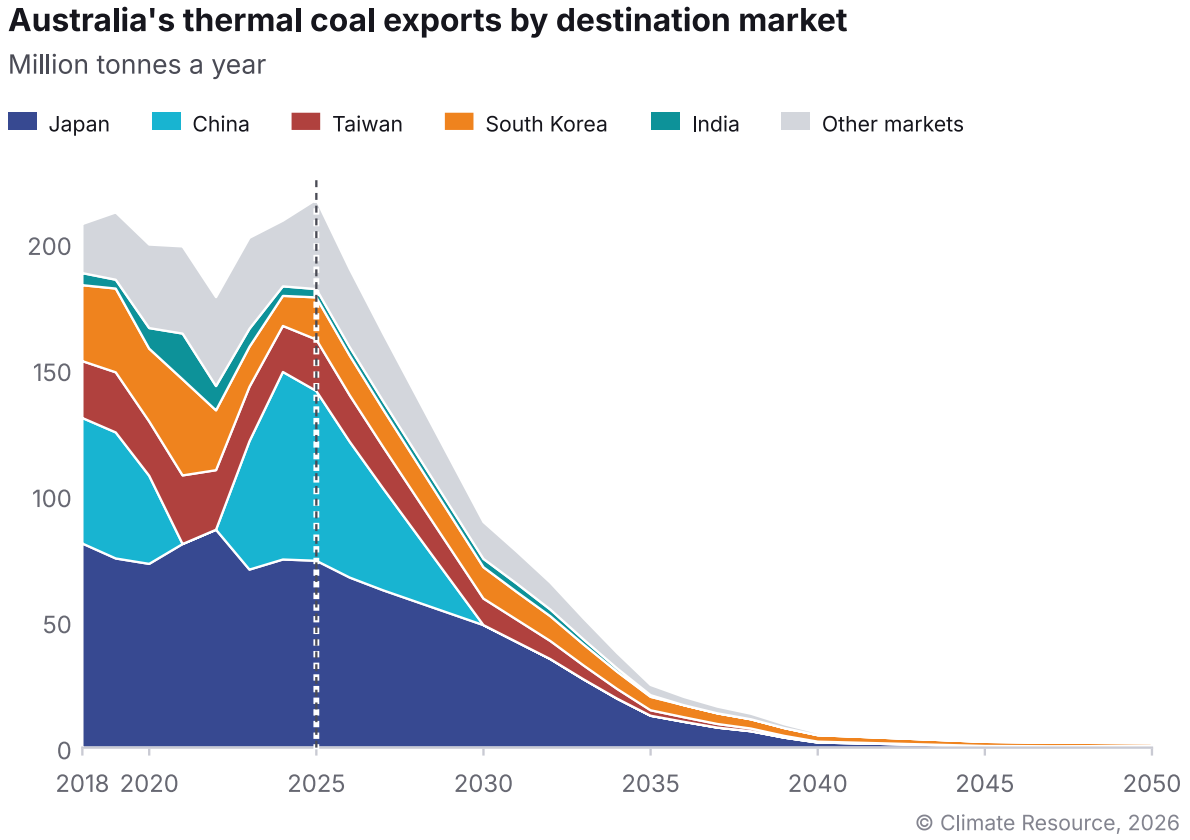


Figure 6: Australia's thermal coal exports by destination market, 2018 to 2050 (Mt per year): observed to 2024, then each market's lowest-overshoot median (scenario based, not a forecast). Source: DISR (2026c), Resources and Energy Quarterly, September 2026 (historical data, Table 41); ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

India has a similar structure, starting from a smaller Australian share and turning down a little later. It produces around 85% of its thermal coal, and there is evidence that this substitution is already under way. Over the two years to the first half of 2026, clean energy met all of the

[55] Reuters (2023); Bloomberg (2023).

7% rise in India's electricity demand, coal power did not grow for the first time in more than 50 years, and the use of imported coal in power generation fell 38%, even as India continues to build new coal plants and mines.[56]

Under this outlook, Australia's thermal coal exports fall from 209 Mt in 2024 to 90 Mt in 2030 and 6 Mt in 2040 (Figure 6), 97% below 2024, with about 2 Mt remaining in 2050. Japan (75 Mt to 2 Mt) and China (74 Mt to zero) account for most of the fall. The outlook has a long tail of small residual volumes, so the year in which exports 'end' depends on where the line is drawn. We report the year in which exports fall below 20%, 10%, 5%, 2% and 1% of their 2024 level (Table 1). The exit years run from the 20% year to the 5% year.

Thermal coal exports fall below 20% of their 2024 level in 2034 and below 5% in 2039, so its exit years are 2034 to 2039 (see Box 1), when the remaining demand likely no longer supports an export industry of many mines, shared rail and port systems and the regions that depend on them.

Table 1: Years in which Australia's thermal coal exports fall below given shares of their 2024 level (209 Mt), from Figure 6.

Share of 2024 exports	Volume (Mt)	Year exports fall below
20%	42	2034
10%	21	2036
5%	10	2039
2%	4	2043
1%	2	after 2050

DISR reported that thermal coal imports in April–June 2026 increased year-on-year by 8% in Japan, 40% in South Korea and 11% in Taiwan. It linked the increase to elevated LNG prices and energy market uncertainty following disruption to shipping through the Strait of Hormuz, including efforts by South Korean utilities to conserve LNG stocks. However, DISR forecast that Japanese and South Korean thermal coal imports would decline over its outlook to 2031.[57] The long-run scenarios presented here have not been recalibrated to incorporate the disruption.

Australian thermal coal use aligned with a 1.5°C pathway

Australia used about 1,380 petajoules (PJ) of thermal coal in 2024–25, almost all of it to generate electricity.[58] Coal supplied 45% of Australia's electricity in 2024, from power stations in New South Wales, Queensland, Victoria and Western Australia.[59] A small remainder is used by industry, mainly alumina refining and cement.[60] Domestic use has already been falling for more than a decade. It is about 30% below its 2010–11 level as

[56] Myllyvirta and Aggarwal (2026).
[57] DISR (2026c), pp. 50–52.
[58] DCCEEW (2026b), Tables A and F.
[59] DCCEEW (2026b), Table O.
[60] DCCEEW (2026b), Table F.

rooftop and large-scale solar, wind and storage have taken a growing share of generation (Figure 7).

On the median pathway, Australian thermal coal use falls by about 40% by 2030 and by more than 80% by 2035. It drops below 20% of 2025 use in 2035, 10% in 2037 and 5% in 2041, a year or two behind exports. Almost all of the reduction comes from the power sector, as coal generation is replaced by renewables backed by storage and transmission. The pathways differ most on the pace to 2030, from 11% to 89% of today's use, but converge after 2035. Every pathway has domestic coal use below a fifth of today's level by 2040. A few pathways keep a small residual, mostly in industry or with carbon capture, out to 2100.

AEMO's planning scenarios align with the integrated assessment models' (IAMs') 1.5°C pathways. Its 2026 ISP scenarios for the eastern grid and its 2025 outlook for Western Australia's main grid, converted to the coal their power stations would burn, fall faster than the median pathway to 2030, to 200–435 PJ.[61] Two of the three keep a tail of 100–200 PJ into the 2040s and all three reach zero by 2050 (Figure 7). They cover coal for electricity only, 94% of thermal coal use in 2024–25.

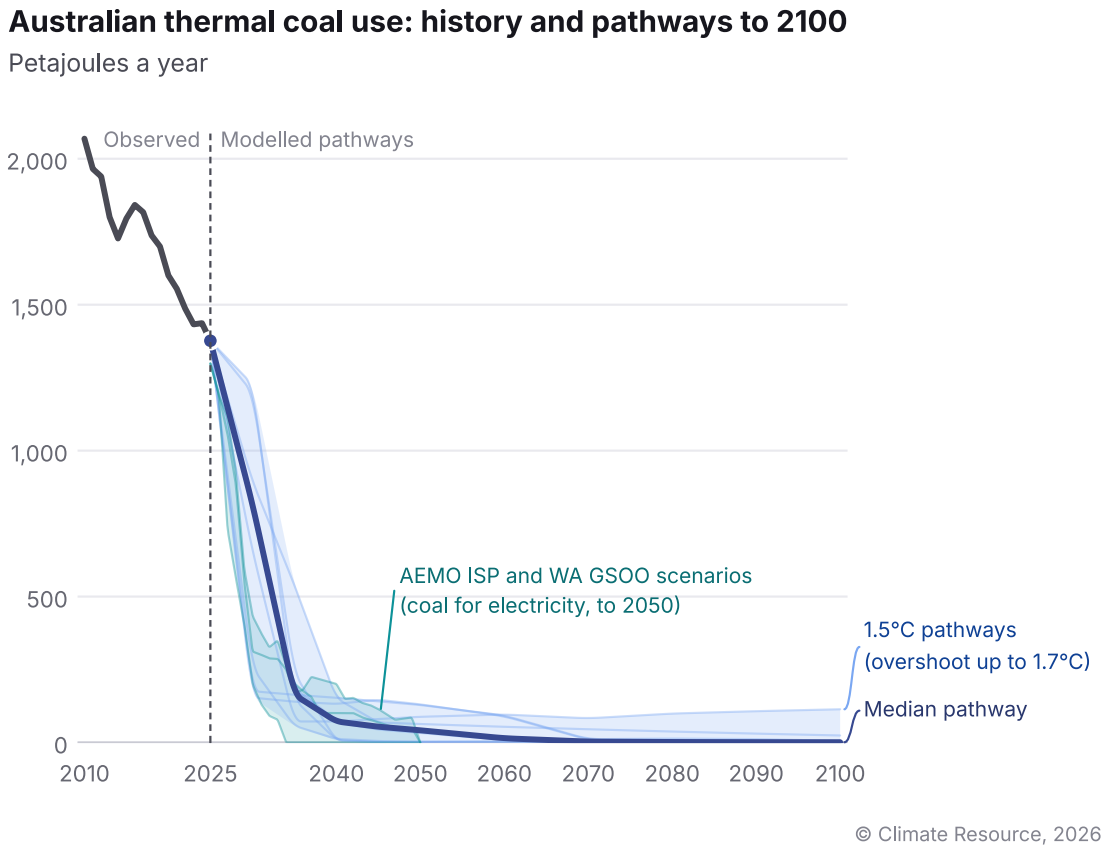


Figure 7: Australian thermal coal use, 2010 to 2100 (PJ per year): observed use, the lowest-overshoot pathways scaled to FY2025, and AEMO coal-generation outlooks for the eastern and Western Australian grids to 2050, converted to estimated coal input using the observed 2024-25 average fleet efficiency. Source: DCCEEW (2026b); AEMO (2026b, 2025); ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.[62]

[61] AEMO (2026b), scenario generation and storage outlook workbooks; AEMO (2025), data register Figure 11 (SWIS coal generation by scenario).

[62] Observed thermal coal use is DCCEEW primary coal less the black coal used in iron and steel, a proxy. The pathways are indexed to their own 2025 value and scaled to that FY2025 figure. AEMO's coal-generation outlooks are converted to estimated coal input using the observed 2024-25 average fleet efficiency; they are not rescaled to match total thermal coal use.

Australia's own grid planners already expect most coal generation to be gone within about a decade, consistent with a 1.5°C world. AEMO's 2026 ISP treats the closure years owners have advised as the latest dates each plant will run and retires plants on or before them. In its Step Change scenario, nearly two-thirds of the remaining National Electricity Market (NEM) coal fleet retires by 2035, faster than announced, with most gone by 2038 and all by the financial year ending June 2050. Plants are projected to close earlier where they are no longer needed for reliability or security and are uneconomic to run, which AEMO expects for some Queensland plants.[63] Victoria's Yallourn is due to close in 2028 and Loy Yang A in 2035 and Loy Yang B in 2047. WA's state-owned coal plants are due to close by 2029 and NSW's Eraring in 2029.[64] Queensland's plans are mixed. Gladstone is due to close in 2029 and Tarong by 2037, but under the state's 2025 Energy Roadmap its other state-owned plants are to run to the end of their technical life. Stanwell's last unit is now not due to close until 2046.[65] About 4.1 gigawatts (GW), or 18% of today's coal capacity, has an advised closure year after 2040; another 1.4 GW has no advised closure date (Figure 8). The median pathway has domestic thermal coal use below 5% of today's level in 2041. Those closure dates assume a slower transition than a 1.5°C world allows.

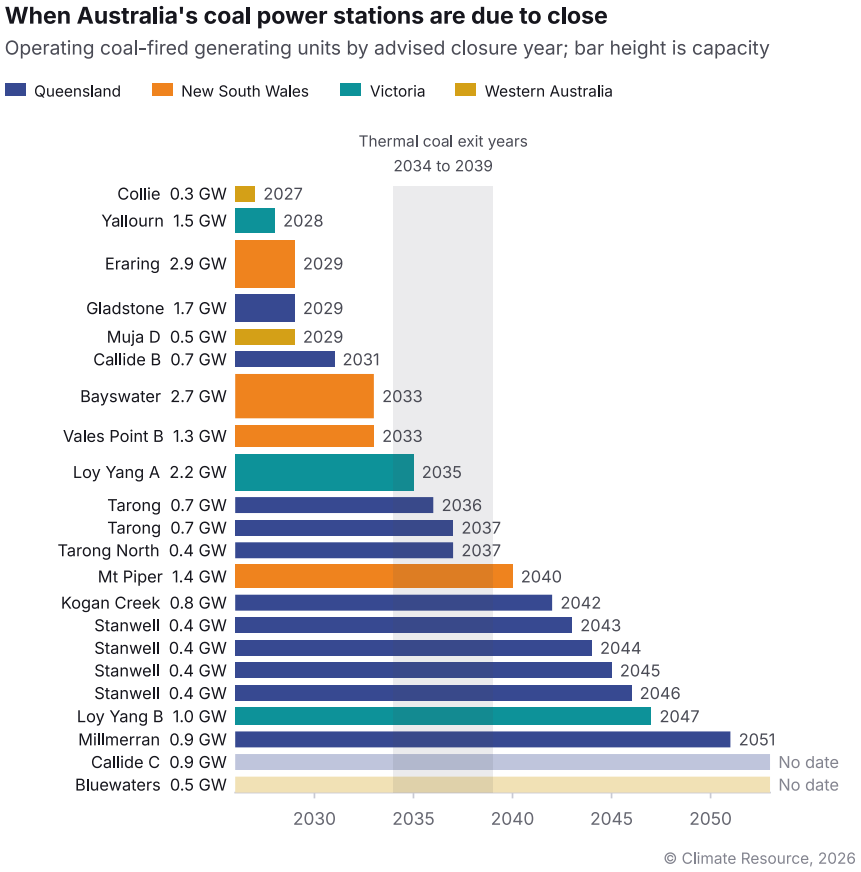


Figure 8: When Australia's coal power stations are due to close: one bar per station and advised closure year (bar height is capacity, GW), against thermal coal's exit years, 2034 to 2039 (Figure 27). Callide C and Bluewaters have no advised year. Source: AEMO (2026d); Government of Western Australia (2022); Global Energy Monitor (2026); Climate Resource analysis.[66]

[63] AEMO (2026b), pp. 6, 73, 76 and 123.

[64] AEMO (2026d); Government of Western Australia (2022); Origin Energy (2026).

[65] Queensland Government (2025); AEMO (2026d).

[66] Closure years are those advised to AEMO (2026d) and, for Western Australia, by the Government of Western Australia (2022); capacities are from Global Energy Monitor (2026).

Australia’s metallurgical coal industry exits between 2042 and 2050

Australia's metallurgical coal exports: demand in a 1.5°C world

Australia’s position at the high-quality end of the market is why its metallurgical coal exports outlast its thermal coal. Coke for a blast furnace needs coal with particular caking strength and low ash, and many coal-producing countries cannot mine enough of it.[67] Domestic production is therefore a weaker guide to metallurgical coal imports, and grade matters as much as quantity. Figure 9 shows, for Australia’s main metallurgical coal markets, the pathway median and the individual lowest-overshoot pathways of modelled demand, and how demand splits between countries’ domestic production and their imports, including the Australian share to 2050.

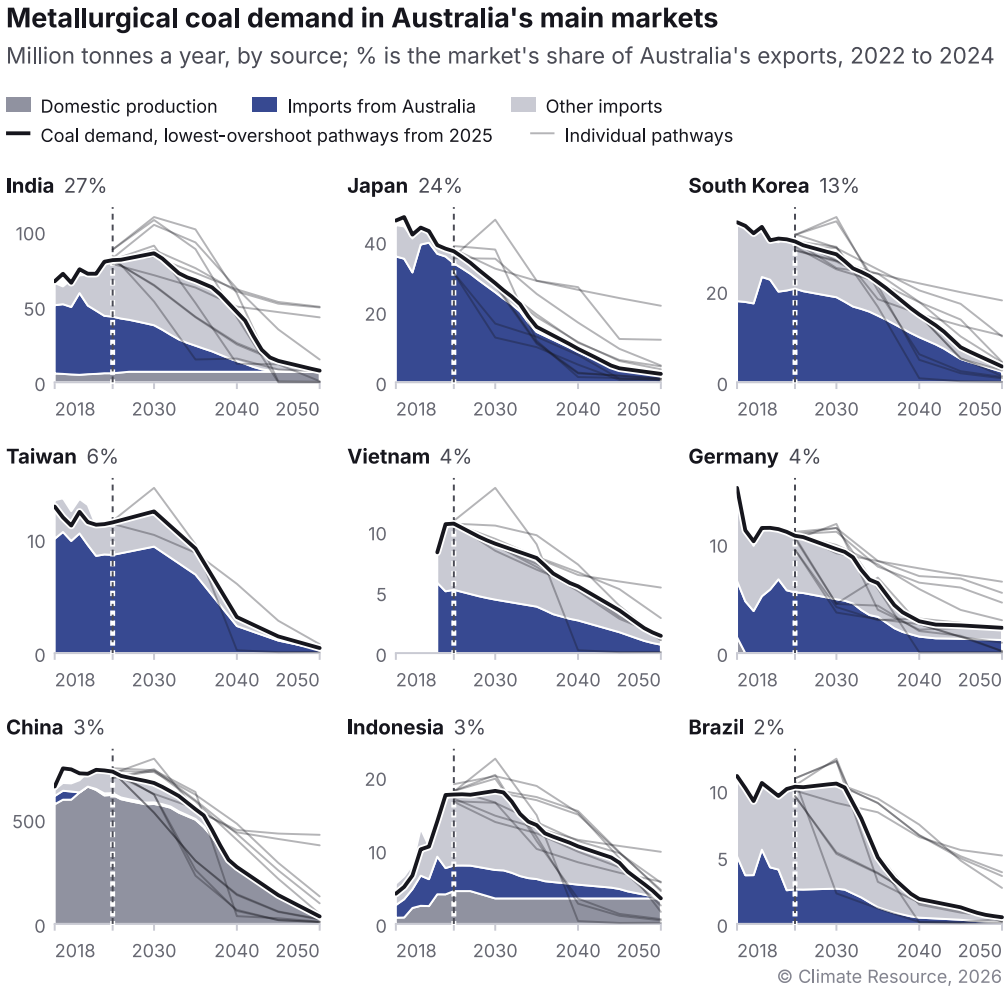


Figure 9: Metallurgical coal demand in Australia’s nine main export markets (Mt per year), by source: observed to 2024, then the lowest-overshoot median (thin lines: individual pathways). Panels have own scales. Source: DISR (2026c); US EIA (2026a); IEA (2014–2025, 2026d); Eurostat (2026); BPS (2025); KEEI (2026); Coal Controller of India (2015, 2025); VDKi (2019–2025); Argus Media (2020, 2024); Van Vuuren et al. (2026); Climate Resource analysis.

[67] Díez et al. (2002).

India, Japan, South Korea, Taiwan, Vietnam, Germany, China, Indonesia and Brazil together account for around 87% of Australia's 2022–2024 metallurgical coal exports.[68] This market base is more geographically diverse than thermal coal's. Metallurgical coal exports reach steelmaking economies beyond the region, including Germany, Brazil and Türkiye, reflecting the geography of global steel production.[69] The IEA estimates that Australia was the largest exporter of metallurgical coal in 2024, accounting for around 42% of global exports. Mongolia (56 Mt), the United States (52 Mt) and Russia (49 Mt) were the next largest exporters.[70]

China is one of Australia's largest thermal coal markets (21% of exports, after Japan's 39% over 2022 to 2024) but one of its smallest metallurgical coal markets (3%). Mongolia and Russia collectively supply around 80% of Chinese metallurgical coal imports.[71] The majority of China's metallurgical coal is domestically produced.[72]

India is an example of why grade matters. Despite holding some of the world's largest coking coal reserves, India's raw coking coal typically carries 34–38% ash and must be washed to 16–18% before it can be blended with imported low-ash coal.[73] High-ash coal makes weaker coke and causes problems in the blast furnace, which is why India still imports around 85–90% of its coking coal. India is also the one market where Australia's share is not held constant. Australia's share of India's imports has been falling as India buys more from other suppliers, and the analysis continues that decline from 2025 at half its historical rate. Holding Australia's share of India's imports constant moves the year exports fall below 10% of 2024 from 2045 to 2047 and the start of its exit years from 2042 to 2043, but leaves the end of metallurgical coal's exit years at 2050, because by then India's own need for imported coking coal has become very small. What sets the end date is how quickly India's steelmaking moves off coal and how much coking coal it can produce and wash at home.

Figure 10 shows Australia's metallurgical coal exports by destination market under the lowest-overshoot demand pathways to 2050. The decline is slower and shallower than for thermal coal. Exports fall from 153 Mt in 2024 to 123 Mt in 2030, 38 Mt in 2040 and 6 Mt in 2050. That's 75% below 2024 by 2040 and 91% by 2045. The decline reflects steelmaking moving off coal, through electric arc furnaces running on scrap and direct reduction of iron ore with gas and later hydrogen.[74]

[68] Türkiye accounts for under 2%, so falls below the threshold for a panel in Figure 9.

[69] Gaulier and Zignago (2010); CEPII (2026).

[70] IEA (2025a), p. 71 and Table 12.

[71] SX Coal (2026).

[72] IEA (2025a), pp. 71–73; SX Coal (2026).

[73] Srikanth (2024), pp. 10 and 57.

[74] IEA (2020).

Table 2: Years in which Australia's metallurgical coal exports fall below given shares of their 2024 level (153 Mt), from Figure 10.

Share of 2024 exports	Volume (Mt)	Year exports fall below
20%	31	2042
10%	15	2045
5%	8	2050
2%	3	after 2050
1%	1.5	after 2050

Where thermal coal's outlook is close to a full phase-out within fifteen years, metallurgical coal retains a meaningful, though much reduced, export volume out to 2050. We report the same thresholds as for thermal coal, with the exit years again running from 20% (31 Mt) to 5% (8 Mt), 2042 to 2050 (Table 2). Thermal coal's exit years span five years; metallurgical coal's span eight.

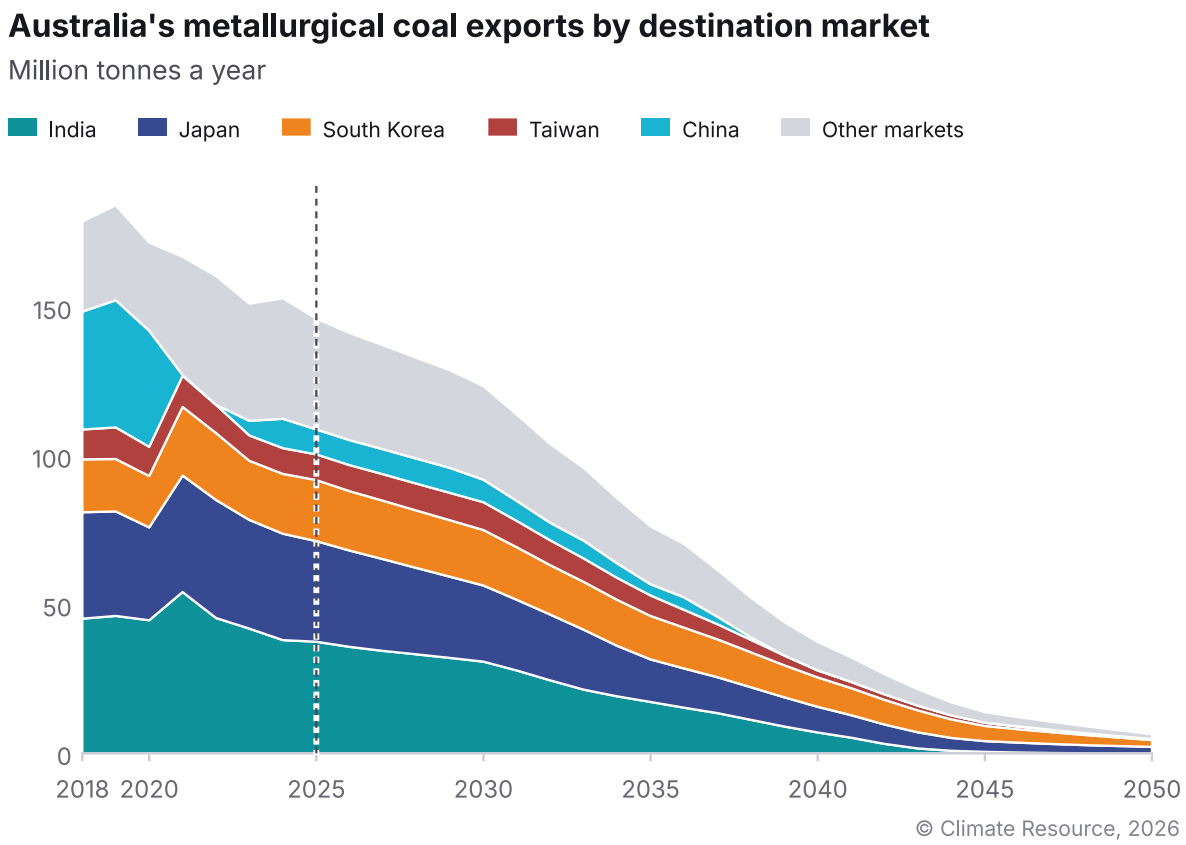


Figure 10: Australia's metallurgical coal exports by destination market, 2018 to 2050 (Mt per year): observed to 2024, then each market's lowest-overshoot median. Demand follows the models' industrial coal use, as the published pathways do not report coal use in steelmaking separately (Appendix A4). Scenario based, not a forecast. Source: DISR (2026c), Resources and Energy Quarterly, September 2026 (historical data, Table 41); ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

Australian metallurgical coal use aligned with a 1.5°C pathway

Australia's own use of metallurgical coal is small. It burned about 90 PJ in 2024–25, around 3 Mt (Figure 11).[75] That is about 2% of what Australia exports. Use has already fallen by more than a third since 2010, as steel output has declined and the industry has consolidated.

On the median pathway, domestic use falls steadily to around half its current level by the mid-2030s, then drops sharply in the early 2040s. It falls below 5% of 2025 use in 2048. In practice the date will be set by a few decisions about specific furnaces rather than by a gradual decline. A blast furnace is relined roughly every 15 to 20 years, at a cost of around a billion dollars, and each reline commits a steelworks to coal for another campaign.[76] The alternative is to switch to processes that use little or no coal, such as electric arc furnaces running on scrap, or direct reduction of iron ore using gas and later hydrogen.[77] With Whyalla's furnace now shut for good, the timing of Port Kembla's next reline is the decision that matters.[78]

Figure 11 (the pale blue plume) shows that the spread between pathways is wide.

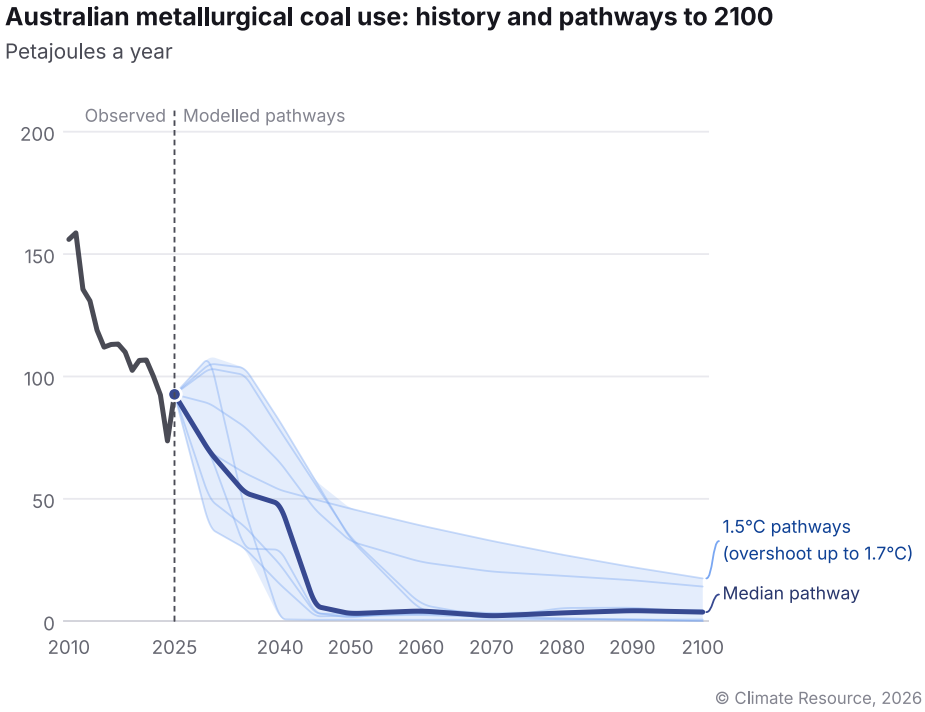


Figure 11: Australian metallurgical coal use, 2010 to 2100 (PJ per year): observed coal used in iron and steel, and the lowest-overshoot pathways' industrial coal scaled to FY2025. Source: DCCEEW (2026b); ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.[79]

In one pathway, domestic metallurgical coal use is close to zero by 2040, but most still use 15–80 PJ in 2040 before falling further, and in two a residual of 14–18 PJ remains to the end

[75] DCCEEW (2026b), Table F.

[76] BlueScope (2023); IEA (2020).

[77] IEA (2020).

[78] The New Daily (2026); Department for Energy and Mining (2026).

[79] Observed use is DCCEEW's black coal used in iron and steel, a proxy for metallurgical coal. The pathways' industrial coal, their metallurgical driver, is indexed to its own 2025 value and scaled to that FY2025 figure.

of the century. Part of the reason is how the models represent steel. Few of them model Australia's steel sector separately, so the domestic pathway uses each model's industrial coal use as a guide, and that also includes coal used for heat in other industries. The domestic results for metallurgical coal are therefore less certain than for thermal coal. The export outlook uses the same measure. [80]

Australian coal in 2035: an industry reshaped

By 2035, the year of Australia's next national emissions target, the coal industry would look quite different under a 1.5°C pathway. Exports fall from 362 Mt in 2024 to around 100 Mt in 2035, a drop of more than 70%. Thermal coal, nearly 60% of exports today, falls to around 25 Mt, while metallurgical coal holds at around 76 Mt (Figure 12). Coal exports in 2035 would be mostly metallurgical, and mostly from Queensland.

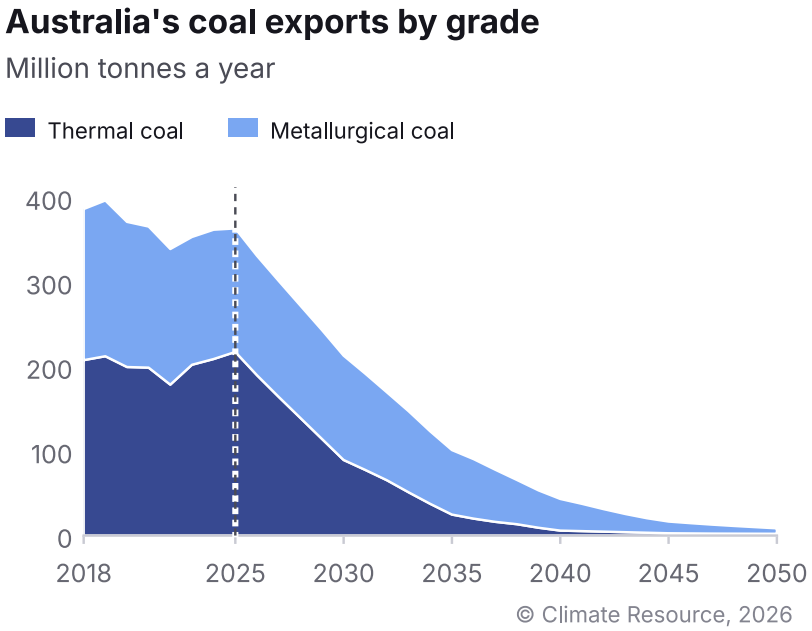


Figure 12: Australia's thermal and metallurgical coal exports, 2018 to 2050 (Mt per year): observed to 2024, then the sum of the market outlooks in Figures 6 and 10. Scenario based, not a forecast. Source: DISR; ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

On the median pathway, domestic coal use in 2035 is around 15% of its 2025 level. Almost all of the fall comes from renewable electricity, efficiency and electrification rather than substitute fuels. By 2050, solid biomass and coal with carbon capture together supply less than a tenth of today's use.

By the end of 2035, power stations holding about 60% of today's coal generating capacity are due to close, including Eraring, Bayswater, Vales Point, Gladstone, Yallourn and Loy Yang A (Figure 8). The pathway has domestic thermal coal use more than 80% lower by then. To close the gap means some of the remaining plants will need to be retired earlier or run less often.

[80] Climate Analytics' fossil fuel phase-out study takes a more direct approach by assuming that coal leaves Australian steelmaking by the early 2030s and that by the 2040s the sector runs entirely on electricity and green hydrogen. That would bring domestic metallurgical coal use to effectively zero more than a decade earlier than our median pathway. See Houlie et al. (2026) and Climate Analytics (2026).

Put together, exports and domestic use decline at a similar pace, so a fall in one is not offset by the other (Figure 13). This is most relevant for thermal coal, where the domestic market is large enough to matter and both fall below 5% of today's levels within two years of each other (exports in 2039 and domestic use in 2041). For metallurgical coal, domestic use is about 2% of exports, so exports alone set the pace. In 2035, the industry as a whole is just over a quarter of its current size.

The coal industry as a whole, use and exports together, has exit years of 2034 to 2039 for thermal coal and 2042 to 2050 for metallurgical coal under this pathway. These are the same years as for exports alone, because exports make up most of the volume (Figure 13).

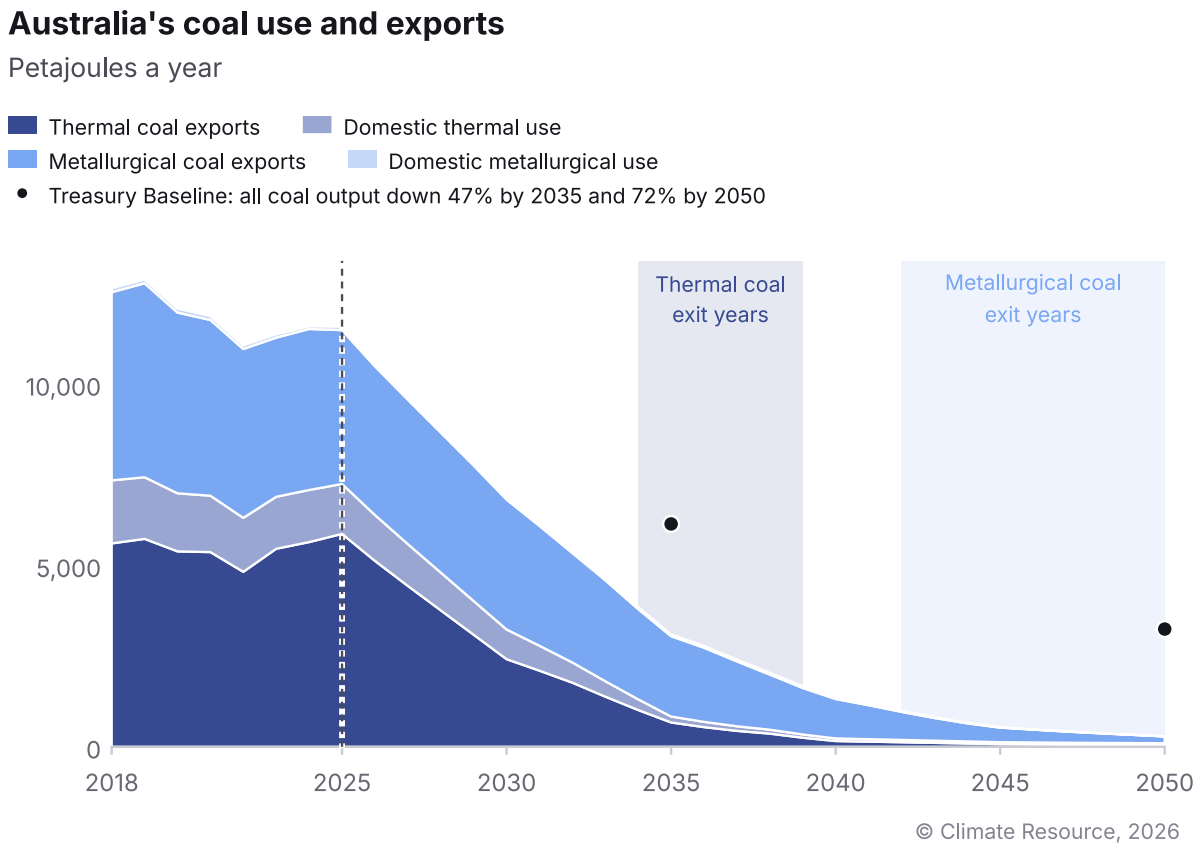


Figure 13: Australia's coal use and exports, 2018 to 2050 (PJ per year): median pathways for each grade, domestic use stacked on exports, with Treasury's Baseline for all coal output marked. Shaded spans are each coal's exit years (Figure 27). Source: DCCEEW (2026b); DISR; Treasury (2025); ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

However, there are different stories in each coal region. In New South Wales and Queensland, exports set the timing. In Victoria's Latrobe Valley and at Collie in Western Australia, where mines supply only local power stations, the end date is set by the closure of those stations. The Hunter Valley is exposed on both fronts as its mines supply export terminals and NSW power stations, and both markets decline within the same decade (Table 3).

These are dates for when customers stop needing Australian coal, in line with our demand-led methodology. They are not necessarily the dates when Australia stops supplying coal. For parts of the industry, that second milestone could arrive earlier.

Table 3: Australia's coal regions today and in 2035 under the lowest-overshoot pathway: FY2024–25 shipments by port system, and the median pathway with the advised power station closures. Source: Queensland NRMMRRD; Coal Services; Port of Newcastle; ABS customs data via the Queensland Government Statistician's Office (NSW grade split); AEMO; Climate Resource analysis.

Region	Today	In 2035 under the 1.5°C pathway
Hunter Valley and Newcastle (NSW)	146 Mt of exports through Newcastle, 92% thermal; supplies Bayswater, Eraring and Vales Point	Thermal exports down by more than 80% and all three power stations it supplies closed. The largest fall of any region.
Western coalfields (NSW)	Supplies Mt Piper	Mt Piper running to 2040 could be the main remaining domestic market in NSW
Central Bowen Basin (Hay Point and Dalrymple Bay)	94 Mt of exports, 81% metallurgical	Still the industry's core, on metallurgical coal. Thermal output now mostly a by-product.
Northern and southern Queensland (Abbot Point, Gladstone and Brisbane)	104 Mt of exports, 54% metallurgical	Thermal exports largely gone but mines that supply Tarong, Stanwell, Kogan Creek, Millmerran and Callide C continue for the domestic market
Latrobe Valley (Vic)	Supplies Yallourn and Loy Yang A and B	Only Loy Yang B left, to 2047
Collie (WA)	Supplies Collie, Muja D and Bluewaters	Only Bluewaters left, with no closure date

The reason for this can be seen clearly through a few maps. Figure 14 maps Australia's coal basins, operating mines, coal haul railways and export ports, showing each mine's output and thermal and metallurgical mix and the volume each port shipped by grade in 2024–25. Figure 15 isolates the five export systems of Queensland and New South Wales, and Figure 16 enlarges each so the individual mines, rail lines and ports can be read.

Australian coal reaches export markets through a few port groupings that include mines, rail corridors and port terminals: the Hunter Valley and Illawarra in New South Wales, and Abbot Point, Hay Point and Dalrymple Bay, and Gladstone and Brisbane in Queensland. Each anchors a regional economy built around the export system. The maps show that several of these systems carry both thermal and metallurgical coal: Dalrymple Bay Coal Terminal ships both; Hay Point Coal Terminal is metallurgical only but draws on the same rail corridors and producing region.

Australia's coal mines and export systems

All operating mines, coal basins, haul railways, export ports and exports by grade

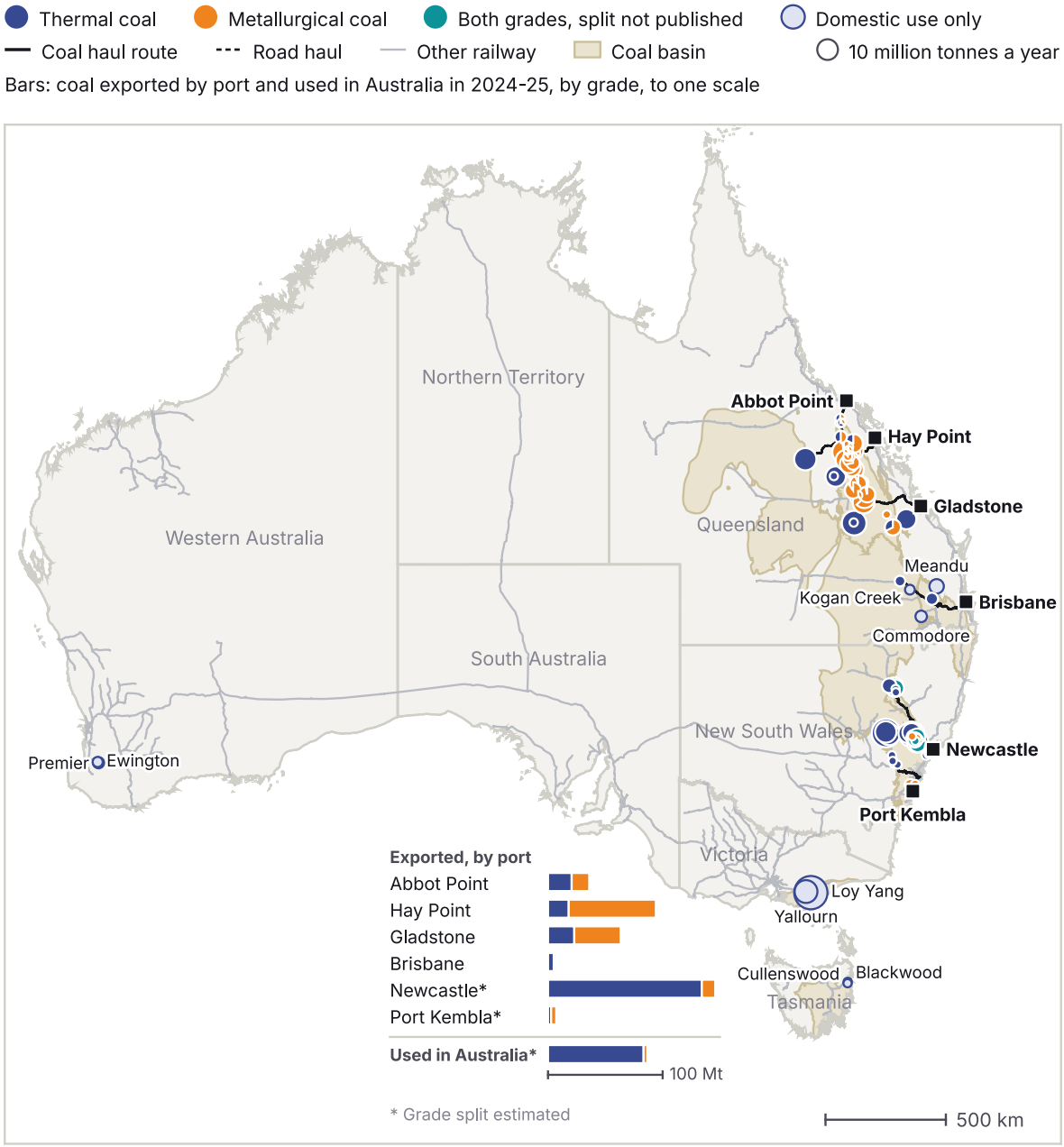


Figure 14: Australia’s coal mines and export systems: basins, operating mines by output and grade (domestic-only mines ringed), haul railways and ports, with FY2024–25 shipments by port and domestic use. Notes and sources: Appendix A5.[81]

[81] Mine output: Queensland FY2025–26; New South Wales 2024 saleable production; other mines the latest reported year, with Loy Yang and Yallourn scaled to 2024–25 brown coal use. Bars: FY2024–25. Methods and sources in Appendix A5.

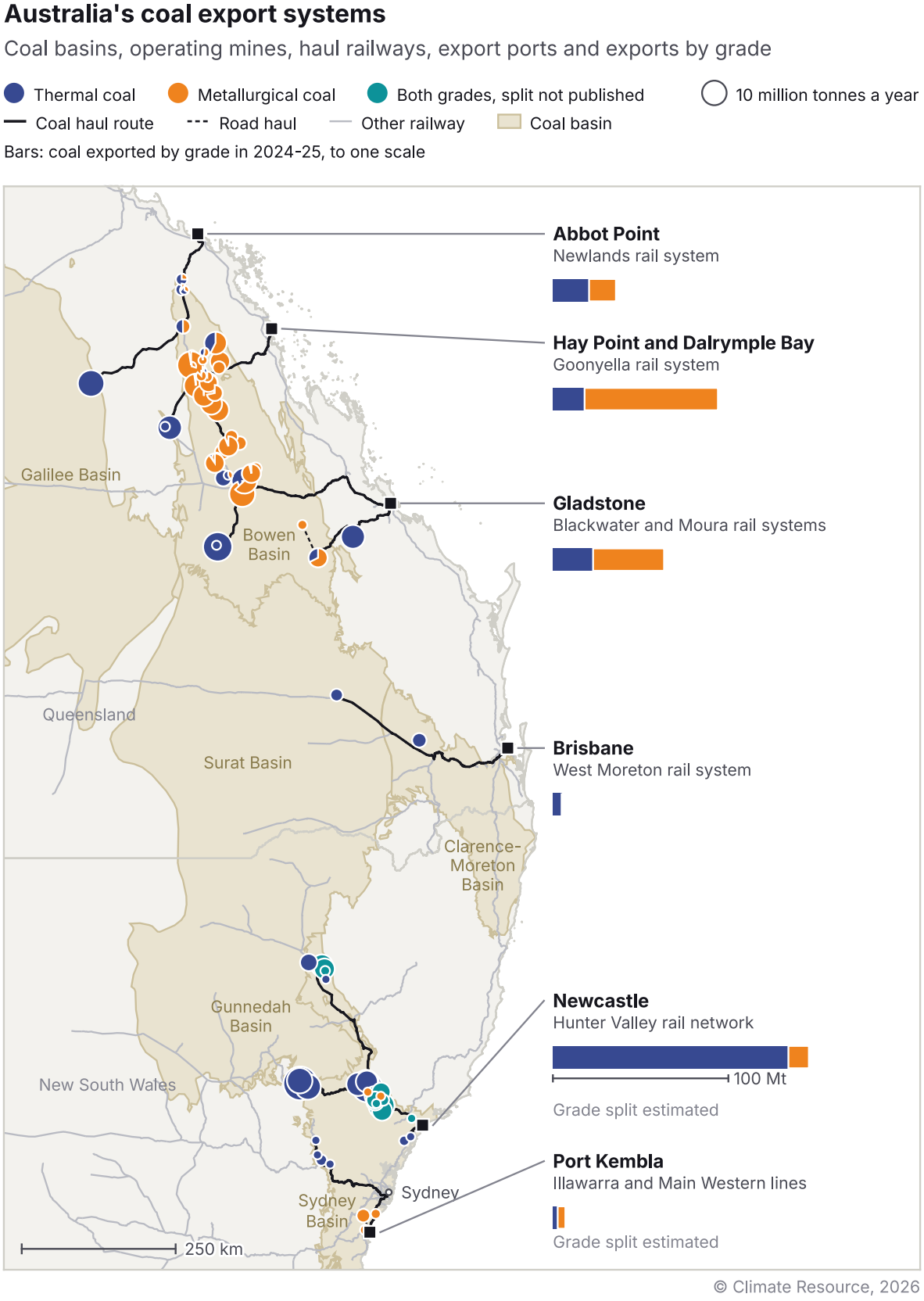


Figure 15: Australia's five coal export systems: mines, haul railways and ports, with FY2024–25 shipments by port and grade. Notes and sources: Appendix A5.

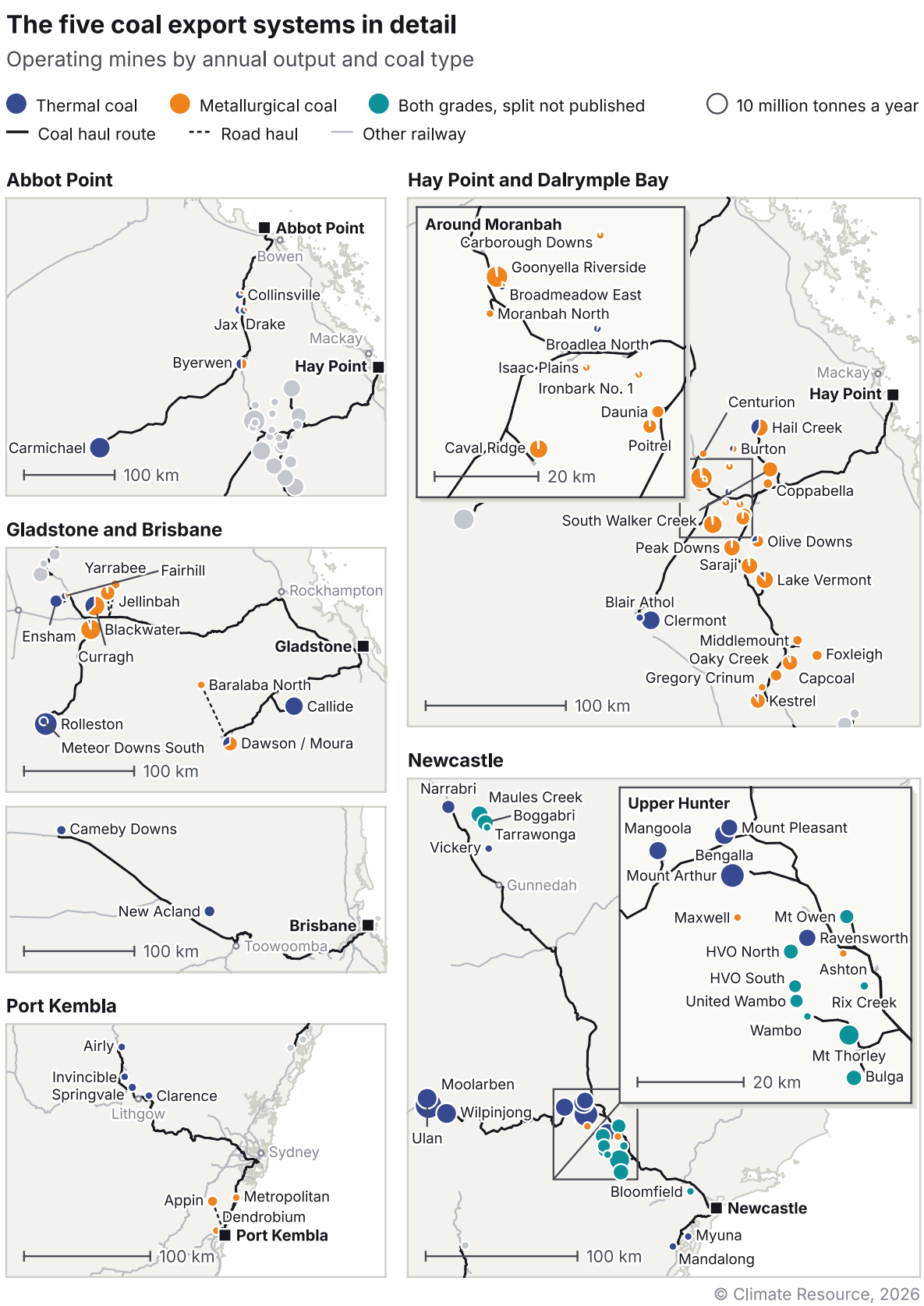


Figure 16: The five coal export systems in detail, each at its own scale. Notes and sources: Appendix A5.

Rail and port infrastructure has both variable and fixed costs recovered from the volume moves through it. As thermal volumes fall, fixed costs are spread across a shrinking base,

raising the delivered cost for the mines and systems that remain. At some point, that can make continuing to move the remaining volume uneconomic, before demand has actually gone. This report does not model system-level costs and does not claim to know whether or when that point is reached. The Institute for Energy Economics and Financial Analysis (IEEFA) has argued a version of this dynamic, a 'cost death spiral,' is already under way in the Hunter Valley, where producers have cut contracted volumes by 40% to 2034.[82] Industry disputes this, pointing to near-record export volumes in recent years.[83]

An 80%-plus demand decline, moving through infrastructure whose costs do not fall at the same pace, is a risk to that infrastructure's continued viability, and therefore to the mines, workers and regions that depend on it. It is also where calls for public support would come, from rail and port operators and the businesses that serve them. Figures 15 and 16 show where that risk concentrates:

- New South Wales (Newcastle and Port Kembla) shipped 153 Mt in 2024–25, 90% of it thermal;
- Central Queensland (Hay Point and Dalrymple Bay) shipped 94 Mt, 81% metallurgical;
- Southern Queensland (Gladstone and Brisbane) shipped 68 Mt, 59% metallurgical; and
- Northern Queensland (Abbot Point) shipped 36 Mt, 57% thermal.
- Hunter Valley mines also supply the state's power stations (Bayswater, Eraring and Vales Point), so some mines lose customers in both markets at once. That coal makes little use of the export rail network, so the power station closures add little to rail access costs.

Three questions arise from this:

1. As thermal volumes fall, does the point at which a thermal-dominant system like New South Wales' becomes uneconomic to run arrive before national thermal demand itself reaches zero?
2. If a system exits early, does some of its residual demand migrate to wherever thermal coal can be supplied most cheaply as a byproduct of a metallurgical coal-dominated system's fixed costs, rather than disappearing?
3. Where mines sell to both export terminals and local power stations, as in the Hunter Valley, does losing the domestic customer in the early 2030s bring forward those mines' economic limit? And can mines that supply a single domestic customer, such as the Illawarra mines supplying Port Kembla's steelworks, stay viable once their export volumes fall away?

Central Queensland's structure, at 81% metallurgical coal, is a plausible candidate for taking up the residual demand for thermal coal from the mid-2030s. Fixed costs are largely recovered from metallurgical coal, so any thermal tonnage carried can be priced close to its marginal cost. Whether buyers currently supplied from New South Wales would actually

[82] Teubner (2026).

[83] Kelly (2026).

switch to Queensland's thermal coal is not considered here and may depend on whether the thermal coal is substitutable for the relevant buyers, mainly Japan and Taiwan.

These dates assume the rail and port systems keep running until the last customer has gone. Prices add a second pressure that this report does not model. Mount Pleasant's expansion would mine up to 21 Mt a year to 2048, and Hunter Valley Operations is approved for up to 26 Mt a year of run-of-mine coal to 2045.[84] Each is above the 6 Mt of thermal coal Australia exports in 2040 on the median pathway. As demand falls, that oversupply would push prices down and close the highest-cost mines first.

Where a thermal-dominant system becomes uneconomic first, its mines could close ahead of demand, and metallurgical exports that share the system could be caught up in the closure. That test would come first in New South Wales and northern Queensland, where more than half of the coal shipped is thermal. A consolidation and closure plan may help to manage this risk (Box 2).

Box 2: Planning for coal consolidation and closure

The timelines show when customers stop consuming Australian coal, under the scenarios explored. When the industry actually stops producing, and in what order, depends on things no single company controls. Left to the market, the exit will be decided contract by contract, and a regional community may learn its outlook from a closure announcement. Scheduled and semi-scheduled generators in the NEM generally must give at least 42 months' notice of closure, unless the AER grants an exemption, and the Net Zero Economy Authority's Energy Industry Jobs Plan supports workers at closing power stations and in some of the businesses that supply them. Nothing comparable yet applies to the export mines, rail lines and ports that carry most of Australia's coal.

A consolidation and closure plan for coal would manage the decline rather than leave it to chance and demand a complementary plan to ensure affected regions prosper as Australia and the region transitions to clean energy exports. It would be agreed with industry, unions and communities. It would:

- set out how the export systems wind down, and how the ones that continue keep their rail and port capacity viable;
- line up mine and system closures with the power station closures already scheduled in the Hunter, Latrobe Valley and Collie;
- give workers, contractors and supply-chain businesses years to plan.

Managing the exit and transition is important for regional communities, and the national economy. Coal exports brought in $71 billion in 2024–25. Replacing that revenue will take new industries on a similar scale. This report does not try to say what those industries should be, but a plan to build on those assets is the counterpart to the dates in this report. It should match the scale of what it replaces and start well before the exit years arrive. Planned early, the decline can be managed without public money being spent later on mines, railways or ports that can no longer pay their way.

[84] NSW Independent Planning Commission (2022, 2026).

What does 1.5°C imply for Australia's gas industry?

Australia is one of the world's three largest exporters of LNG, alongside the United States and Qatar. In 2024–25 it exported about 79.1 Mt of LNG, equivalent on an energy basis to 73.8% of Australia's natural-gas production. Gas consumed within Australia supplies homes, businesses, industry and power stations, including fuel used at LNG plants.[85]

The industry operates as three largely separate markets:

- **Western Australia** produces most of the country's LNG, from offshore fields feeding the North West Shelf, Gorgon, Wheatstone, Pluto and Prelude projects. WA's Domestic Gas Policy, formalised in 2006, requires covered LNG exporters to reserve gas equivalent to 15% of their LNG exports for the WA market over the life of the project or agreement, not in each year. Exporters must also arrange the necessary infrastructure and market the gas diligently and in good faith. Approved alternative-source offsets are possible. LNG processed offshore or in Darwin is outside the policy's scope.[86]
- **The Northern Territory** exports through Darwin LNG and Ichthys, and supplies a small local market.
- **The east coast** links Queensland, New South Wales, Victoria, South Australia, Tasmania and the Australian Capital Territory (ACT) through an interconnected pipeline network. Three LNG projects on Curtis Island near Gladstone began exporting between 2015 and 2016, drawing on the Surat and Bowen basins in Queensland. In 2025, Queensland's LNG export facilities accounted for about three-quarters of gas consumption in AEMO's East Coast Gas Market.[87]

On the east coast in particular, the export and domestic markets are closely bound. They draw on the same fields and the same pipeline network. Domestic wholesale prices have tracked international LNG prices since the export plants started up.[88] In 2024–25, LNG plants consumed about 438 PJ of gas, including on-site electricity generation but excluding gas exported as LNG, equal to more than 40% of the 1,015 PJ used by everyone else in Australia.[89] Under the September 2026 exposure draft, the proposed national gas reservation scheme would require LNG exporters to meet domestic supply obligations from 1 January 2028, based on up to 20% of their annual export volumes and calibrated to domestic demand, with adjustments for existing contracts, infrastructure constraints and state reservation arrangements.[90] As southern gas production declines, Queensland gas production and the operation of its LNG facilities will play a growing role in domestic supply.[91]

[85] DCCEEW (2026b), Tables A and N; Geoscience Australia (2026).
[86] Government of Western Australia (2026a, 2026b).
[87] AEMO (2026a), pp. 13, 18 and 98–102; Queensland Government (2016).
[88] ACCC (2026a, 2026b).
[89] DCCEEW (2026c), pp. 9–10.
[90] DISR (2026a), pp. 3 and 7–8.
[91] AEMO (2026a), p. 13.

These links mean the future of LNG exports has a role in shaping the future of domestic gas supply, and the reverse. This chapter starts with LNG because exports make up most of the industry.

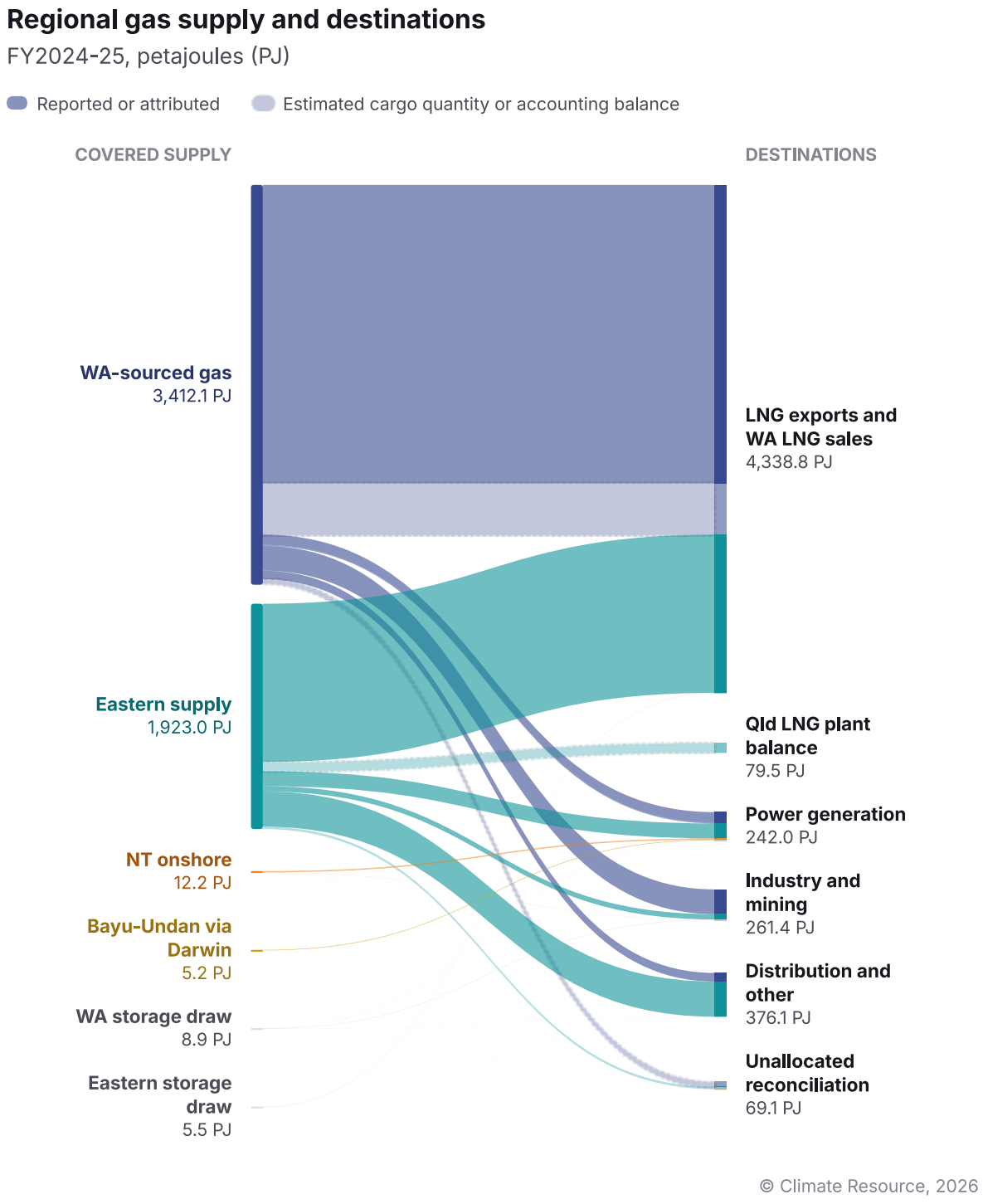


Figure 17: Regional gas supply and destinations, FY2024–25 (PJ): proportional estimates, not observed routes. Source: AEMO Gas Bulletin Board and QED; WA statistics; INPEX; Climate Resource analysis.[92]

[92] A partial regional supply account, not gross production: western LNG plant fuel is unquantified, and the Queensland LNG plant balance includes inventory and metering, not fuel alone. Ichthys exports assume 115 cargoes at 70 kt (60 to 80 kt sensitivity) and 54.4 GJ/t; WA LNG sales stand in for exports.

Australian LNG contracts reach zero in 2042

A focus on uncontracted LNG demand

Three-quarters of the gas produced globally is consumed domestically and the rest is traded internationally.[93] Some is traded by pipeline, which is the cheapest option where the infrastructure exists.[94] As Australia has no pipeline export capacity, it exports gas only as LNG. Global gas demand projections are not highly relevant to questions around Australia's market exposure unless they are narrowed to the LNG segment.

Even a focus on the LNG segment could overstate Australia's addressable market. This is because most of Australia's own production, and most of global LNG, is already committed in long-term contracts. The global LNG trade has historically been dominated by Sale and Purchase Agreements (SPAs) running 15 to 25 years, which commit buyers and sellers to agreed quantities, subject to contractual flexibility, renegotiation and termination provisions. The relevant question for an exporter is therefore not 'how much LNG will the world consume', but 'how much of that consumption is not already committed within a contract'. This is the portion of future demand open to new supply, renegotiation, or exposure to spot pricing.

Figure 18 shows how different the two measures are.

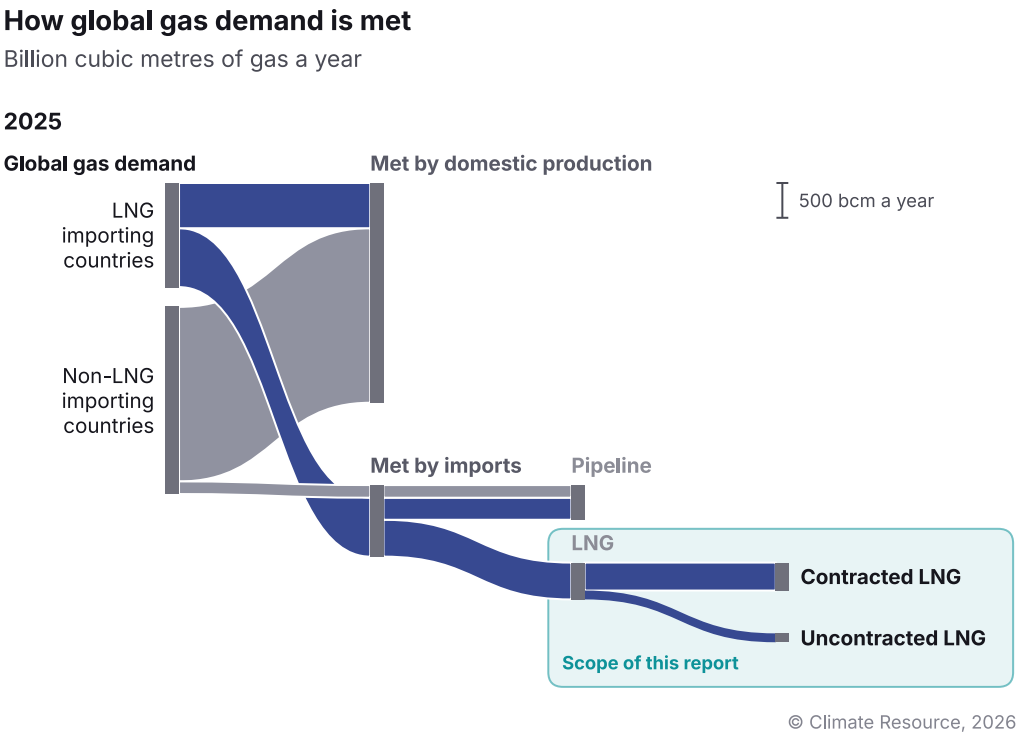


Figure 18: How global gas demand was met in 2025 (bcm per year): the 33 LNG importers in this report (shaded) and all other countries, by domestic production, pipeline imports, and contracted and uncontracted LNG. Source: Energy Institute; US EIA; Türkiye MENR; GIIGNL; LNG contract database (Appendix A2); Climate Resource analysis.

[93] Energy Institute (2026).

[94] Molnar (2022).

Trends in global gas demand are a poor guide to Australia's exposure, because the market an exporter can actually compete for is only about 3% of global gas demand. Of the 4,186 billion cubic metres (bcm) of gas the world used in 2025, the 33 LNG importing countries covered in this report used 36%, and met about a third of that with LNG. LNG therefore met 13% of global gas demand, and term contracts already match about three-quarters of it. Uncontracted LNG, the part an exporter can compete for, was about 3% of global gas demand.

A demand-led analysis

This report adopts the same demand-led framework used in prior Climate Resource LNG analysis, built around the concept of uncontracted LNG demand.[95] Broadly:

- Future gas demand is derived for the world's major LNG-importing economies under relevant climate pathways.
- A supply merit-order is applied where domestic production is taken up first, then pipeline imports, with LNG treated as the residual source once those are exhausted.
- These are aggregated and compared against existing LNG supply contracts, with an allowance for the flexibility built into contracts, which determines the extent to which contracted cargoes can be redirected between markets.[96]
- What remains after netting out contracted supply is the uncontracted LNG demand, which is the market space available for new or spot volumes, including any uncontracted Australian capacity.

Appendix A2 sets out the method in detail, including country coverage, data sources and how contract flexibility is treated.

Limitations of the approach

This method gives a defensible estimate of how much open market space exists for uncontracted LNG supply under a given climate pathway, and of the point at which contracted supply already exceeds structural demand. That is the basis for assessing whether there is room for new Australian supply beyond what is already committed.

However, the method does not say which supplier wins any uncontracted market that remains. That depends on other factors including relative production cost. The method also does not capture the effects of the current Middle East disruption, which is addressed qualitatively below. Finally, the method can only describe what a given pathway would imply, not what will happen.

Australia’s LNG contract cliff

Whether Australia can sell LNG beyond its current contracts depends on whether the global market leaves any room for new ones. Figure 19 shows global LNG export capacity against demand from the 33 importing countries covered in this analysis (accounting for 98.1% of global LNG trade), under the lowest-overshoot demand pathway used throughout this report.

[95] Talberg et al. (2026b).

[96] The method does not capture the legal specifics of individual contracts; destination flexibility is modelled using a proxy based on delivery terms (FOB versus DES), not the terms of any specific agreement.

Total available capacity to 2030 is based on IEA projections of existing and under-construction facilities, and held constant thereafter. The growing gap between total capacity and demand after 2030 should be read as unused headroom rather than a forecast of further capacity additions.

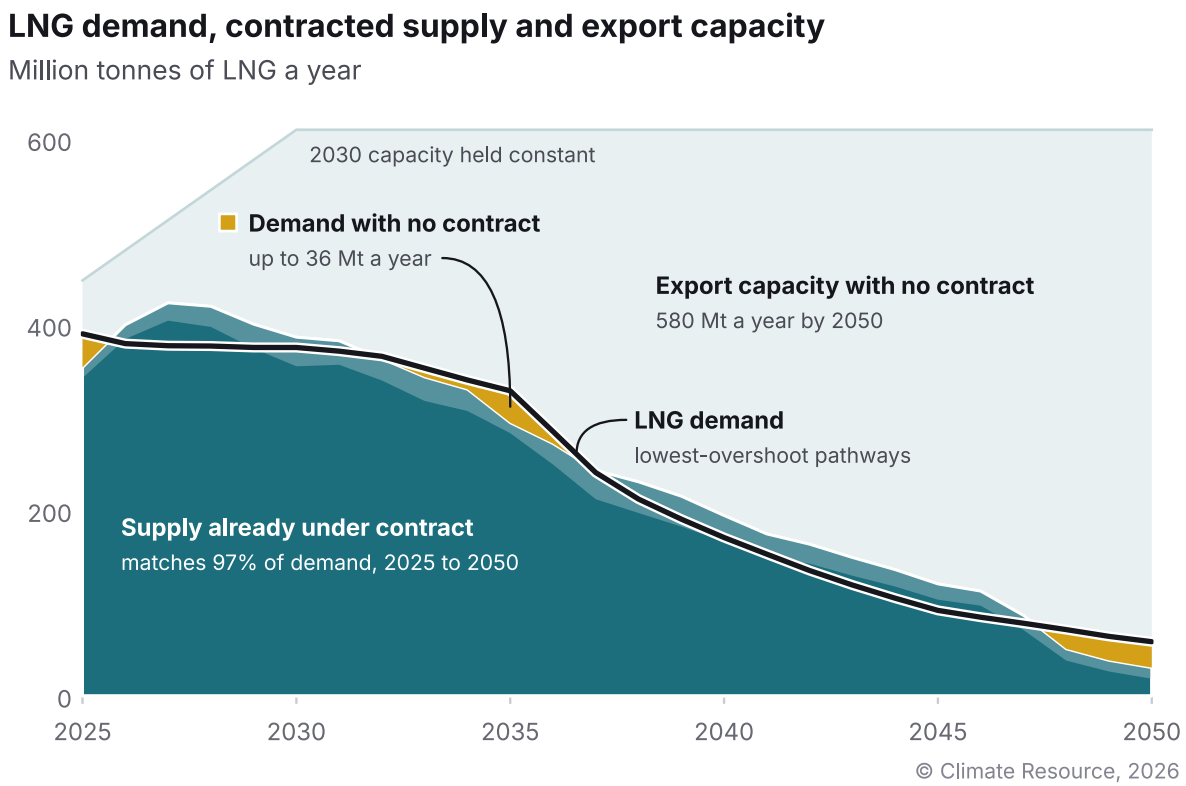


Figure 19: Global LNG demand in the lowest-overshoot pathways against contracted supply and export capacity, 2025 to 2050 (Mt LNG per year). The demand profile is the black line. Supply already under contract (teal) is the capacity captured in disclosed physical offtake contracts, excluding portfolio on-sales. The lighter teal band at the top of that area shows delivered ex-ship (DES) contracts that exceed the importing country's own LNG requirement, assuming each country uses its DES contracts first. DES terms may indicate less flexibility to redirect these surplus cargoes to other markets. Export capacity with no contract (pale) is available liquefaction capacity not covered by the contract register. The mustard slivers mark demand above contracted volume in a given year. Source: IEA (2025d); ScenarioMIP-CMIP7 lowest-overshoot pathways; LNG contract database (Appendix A2); Climate Resource analysis.

Through the second half of this decade, demand tracks close to the edge of contracted capacity. From 2032, contracted volumes fall away slightly faster than demand does, since existing agreements expire on a fixed schedule rather than in step with how demand is actually tracking. This opens a small gap in which demand exceeds contracted supply from 2032 to 2036, peaking at 34 Mt in 2035, before demand tracks closely below contracted supply again through to 2047. A second small gap opens from 2048 as the last of the current contracts expire. The 36 Mt of demand with no contract shown in 2025 is the gap between the LNG these countries needed in that year (390 Mt, from observed gas consumption less domestic production and pipeline supply) and the 354 Mt of contracted supply the register captures. LNG bought outside those contracts, such as spot, short-term and portfolio sales, fills it. From 2026, new contracts lift contracted supply above demand.

Three findings emerge from Figure 19:

- First, in a 1.5°C world, the volumes buyers are expected to need over the next five to ten years are already fully, and slightly more than fully, accounted for by SPAs already signed. There is little uncontracted market space left for a new project to sell into over this period, regardless of cost position. [97]
- Second, the two brief windows where demand does slightly exceed contracted supply, 2032–2036 and from 2048, emerge a decade or more after most new Australian LNG investment decisions would need to be taken.
- Third, the amount of spare capacity already available to compete for these two 'opportunity windows' dwarfs the size of the windows themselves. Export capacity with no contract reaches around 224 Mt per year in 2030 and 580 Mt per year by 2050. QatarEnergy is likely to be among the largest holders of that uncontracted capacity in the 2030s, with low production costs and proximity to South Asia, a forecast growth market.

This is clear evidence for describing the market as structurally oversupplied. In a 1.5°C future, there is more liquefaction capacity than there is new demand to be won, in any year modelled. In this scenario, Australia's current LNG contracts represents a ceiling on future LNG exports (Figure 20).

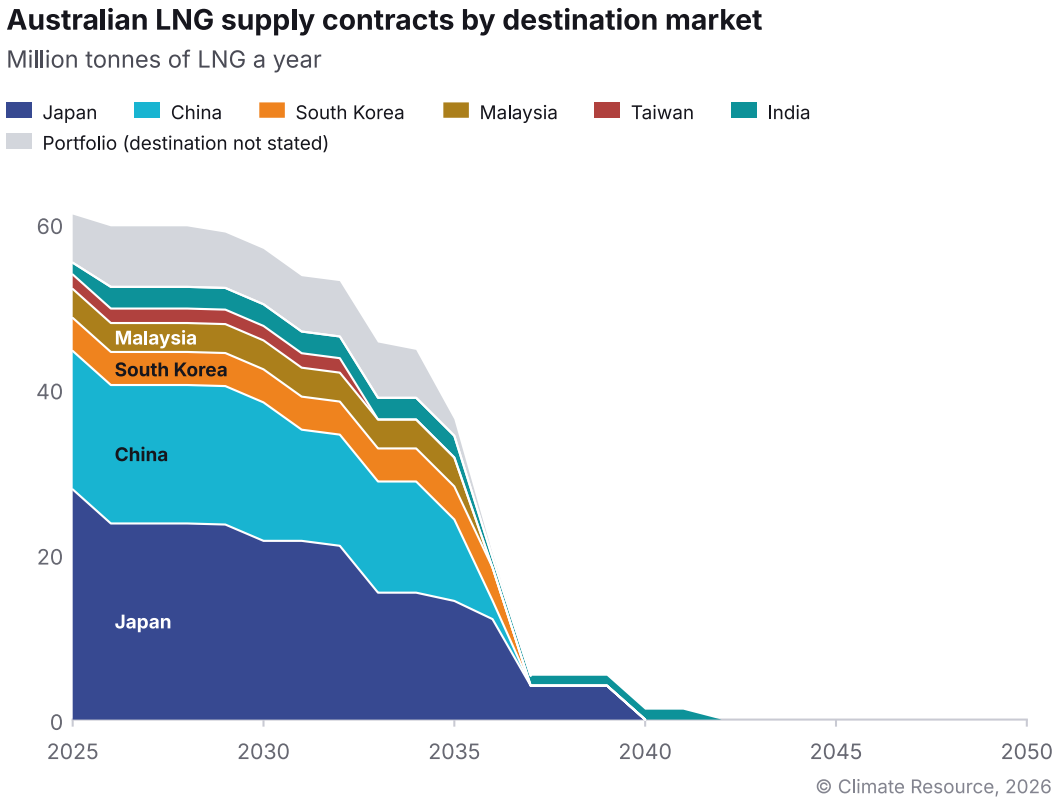


Figure 20: LNG under contract from Australian projects, 2025 to 2050, by destination market (Mt LNG per year): the existing contracts, with no renewals, new contracts or spot sales. Source: LNG contract database (Appendix A2); Climate Resource analysis.

[97] Some of those SPAs are held by portfolio players, traders and LNG sellers who still need to find end users (Appendix A3), so the demand still open at the end-user level may be somewhat larger, and Australian sellers could compete with them for it.

The register captures contracts covering about three-quarters (77%) of Australia’s observed 2024 LNG exports, so the 2025 starting point in Figure 20 sits about a quarter below actual exports. Sales outside captured contracts (spot, short-term and portfolio volumes) are not projected forward.

Contracted LNG deliveries hold roughly steady until 2028, decline moderately to 2035 and steeply to 2037, and first reach zero in 2042. Our earlier analysis tested temperature pathways peaking at 1.6°C, 1.8°C and 2°C, based on the NGFS Phase 5 scenarios, and found oversupply in all of them. Under the 1.8°C and 2°C pathways, some uncontracted demand remains, but existing uncontracted export capacity can meet all of it through 2050. Under the 1.8°C pathway, Middle Eastern capacity alone could absorb all of it from around 2028. A warmer world therefore leaves more uncontracted demand to be won, but not enough to need higher-cost Australian supply. What sets the date Australian LNG exports end is when the current contracts expire, not the temperature outcome.[98]

The 2042 date marks the first zero year in the existing contracts, not a 'no later than' date for all Australian LNG exports. The scenario assumes projects supply their contracted volumes until each contract ends. Contracts running past 2036 are all Western Australian. They are Gorgon deliveries to Japanese buyers which run through 2039 and to India's Petronet through 2041. Queensland's dated contracts end by 2036 and the Northern Territory's by 2035.

Many Asian markets do still need LNG beyond this

Australia's contracted exports may be running down, but that does not mean demand for LNG is disappearing in the markets that Australia supplies. Figure 21 shows domestic production, net pipeline imports and LNG imports for the twelve largest net LNG importers in 2024. Trade observations run through 2024. From 2025, domestic production and pipeline supply follow the conditional base case, and LNG is shown as the volumes buyers in each market hold under purchase contracts. Not all of it will be imported, since buyers can resell or divert cargoes, especially those bought free on board. The black line is gas demand under the lowest-overshoot pathway. A dot marks the modelled year from which domestic production and net pipeline supply meet demand without LNG, conditional on those supply assumptions. For Türkiye, 2037 remains conditional on the retained later production and pipeline assumptions, so it is not a verified end date for LNG imports.[99]

[98] Talberg et al. (2026b).

[99] Türkiye Ministry of Energy and Natural Resources (2026); Woodside (2025); Eni (2025); SEFE (2025).

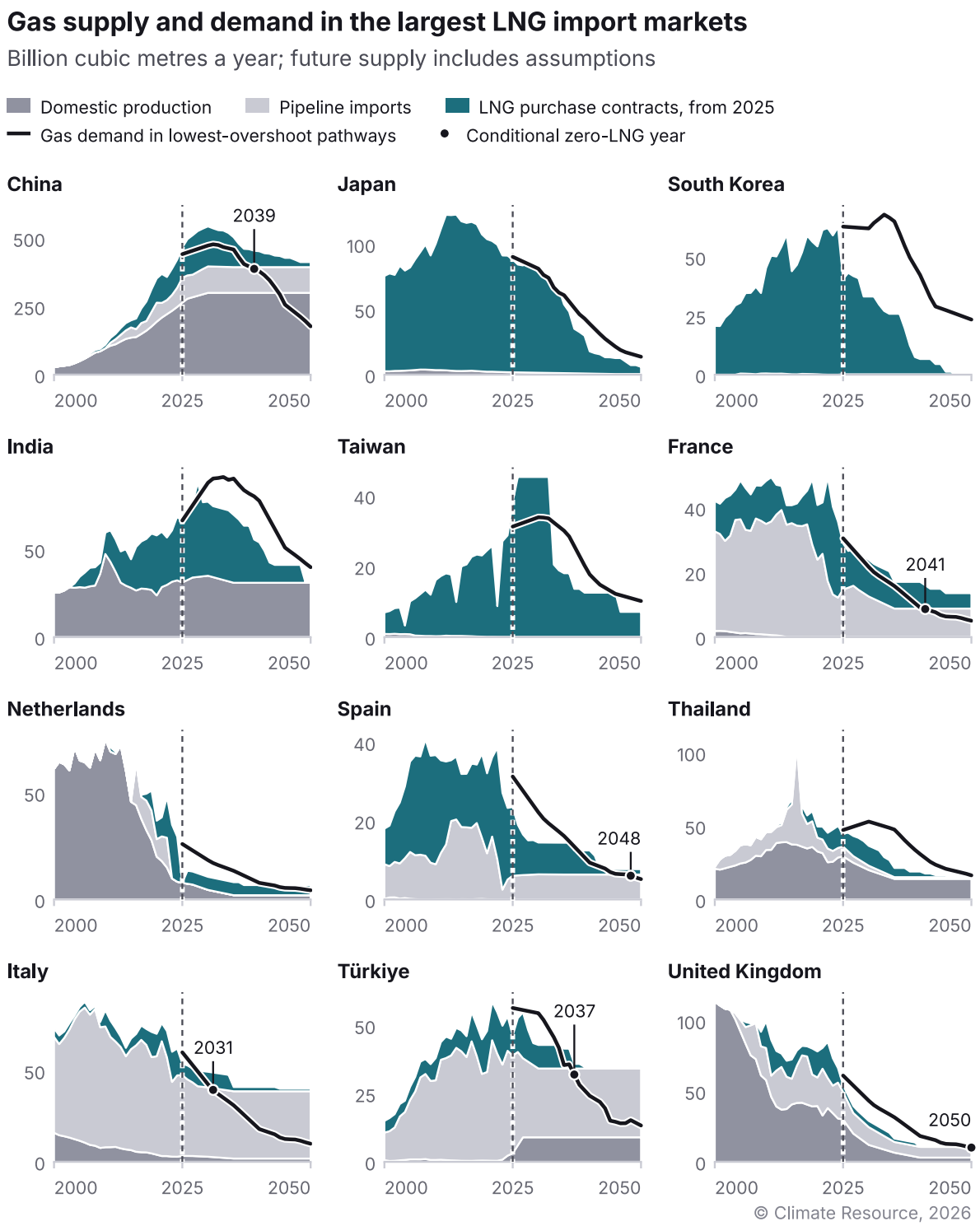


Figure 21: Gas supply and demand in the twelve largest LNG importers (bcm per year): domestic production, pipeline and LNG imports observed to 2024, then base-case supply and LNG purchase contracts against median lowest-overshoot demand (black line). Panels have their own scales. Source: Energy Institute; US EIA; Türkiye MENR; CEPII BACI; Eurostat; ScenarioMIP-CMIP7 lowest-overshoot pathways; LNG contract database (Appendix A2); Climate Resource analysis.

Most of Australia's markets keep importing LNG, although in reduced quantities, to 2050. Gas demand in 2050 is below its 2025 level in all twelve markets, by between 40% (India) and 85% (Japan). China, Japan, South Korea, Taiwan and Thailand together comprised

around 93% of Australia's export volumes over the period 2022-2024. Under a 1.5°C pathway, Japan, South Korea, Taiwan and Thailand continue to require LNG through to 2050, at a fraction of current volumes. China, Australia's second largest single market, is the exception. China's modelled LNG import requirement reaches zero from 2039, as domestic production and pipeline supply come to cover its needs.

Where a market's contracted volumes exceed what it needs, such as is the case for China from 2039, the method reallocates that surplus to other contracted markets still short of supply, to the extent that contract terms allow this flexibility. This means that China's declining requirement does not strand the corresponding cargoes. It makes them available to help meet ongoing demand in markets such as Japan, South Korea, Taiwan and Thailand.

How this plays out with respect to Australia's LNG exports is shown in Figure 20, which stacks contracted deliveries from 2025 by destination market. Japan, China and South Korea hold 80% of the volume under contract in 2025. China's share falls away fastest of the major markets shown, consistent with China being the one major buyer to drop out of the LNG market altogether. By the late 2030s, the residual volume of contracted deliveries that remains is primarily with Japan.

However, the decline in Figure 20 reflects contracted supply running out, not Australia's remaining markets ceasing to import LNG. As previously noted, Japan, South Korea, Taiwan and Thailand are all still projected to need LNG through to 2050. In 2025, LNG met about 20% of China's gas demand, 53% of India's and virtually all of Japan's, South Korea's and Taiwan's. Across all 33 importers covered in this report, the LNG needed to meet their own gas demand falls from 530 bcm in 2025 to 225 bcm in 2040.

What effect from the closure of Hormuz?

The Strait of Hormuz has been effectively closed to commercial shipping since March 2026, taking around a fifth of global LNG supply (Qatar and the United Arab Emirates combined) largely off the market. As at late October, a handful of vessels a day were transiting, against about 85 before the war, and Iran's conditions for reopening had not been met. Iranian strikes damaged two of Qatar's 14 LNG trains, 12.8 Mtpa or about 17% of its capacity, and QatarEnergy expects repairs to take three to five years. The IEA had warned that global LNG supply would fall for the first time since 2012 if the strait was not fully reopened by the start of the fourth quarter. That condition has now been met.[100]

This ongoing crisis has two effects in opposite directions:

- In the near term, Australian exporters are earning an unplanned windfall on LNG sold spot, as Asian buyers pay elevated prices to replace lost Qatari volumes. [101]
- Over the longer term, the disruption could be causing the kind of permanent demand destruction that followed Europe's 2022 gas crisis, rather than a temporary price spike that reverses once the Strait reopens.

DISR expects the disruption to remove 'the global oversupply previously forecast' for 'the next 2-3 years'.[102] Its forecast runs to 2031, before Qatar's damaged capacity is fully

[100] IEA (2026c); Energy Intelligence (2026a, 2026b).

[101] DISR (2026c), pp. 20 and 64. Most of Australia's contracted cargoes are priced against oil benchmarks such as Brent or the Japan Crude Cocktail, so they move with the oil price rather than with spot LNG.

[102] DISR (2026b), pp. 12 and 69.

restored. By 2030, Qatar's expansion and new US projects are expected to add around 220 Mt of liquefaction capacity, although the IEA made that estimate before the Ras Laffan strike and now expects Qatar's expansion to be delayed.[103] In October, Reuters reported that the first QatarEnergy North Field East train was ready to start in November, with LNG production expected in the first quarter of 2027, although a sustained ramp-up depends on unrestricted transit through Hormuz.[104] Even so, taking Qatar's damaged trains out for five years and delaying its expansion by two would still leave uncontracted capacity far above uncontracted demand. Roughly 210 to 550 bcm a year of online liquefaction capacity outside contracts against 20 to 70 bcm is uncontracted demand through 2030. The new supply sits at the low-cost end of the market, while Australia sits towards the high-cost end, well above Qatar. When the market loosens, Australian supply is the most exposed.[105]

Near-term tightness and long-run oversupply are not in tension. They describe different points on the same curve. Demand destruction occurs when buyers take action to permanently replace LNG with a substitute, such as efficiency gains that reduce gas use, fuel-switching to coal or renewables in power generation, or accelerated buildout of grid-scale storage and network capacity that lets renewables cover load LNG previously firmed. Each of these takes years and capital to deliver. It could be several years before planned renewable, storage and grid infrastructure comes online to displace even a portion of LNG demand. Whether genuine demand destruction has occurred, rather than a temporary lull, may therefore not be observable in demand data for several years.

However, some indicators move faster than consumption data. For example, government targets and project decisions in customer countries set the direction of structural demand before it shows in import data. China's 15th Five-Year Plan for oil and gas is a neutral signal, as Kpler estimates it adds only about 0.5 Mt to 2027 LNG imports, through industrial coal-to-gas switching.[106] However, Australia's other LNG markets point downward. Japan's restarted Kashiwazaki-Kariwa 6 reactor is expected to displace around 1.3 million tonnes per annum (Mtpa) of LNG.[107] Taiwan is moving to restart two nuclear plants totalling 3.84 gigawatts (GW), and Thailand's draft 2026 power development plan targets more than 60% clean electricity by 2050.[108]

Falling levelised costs of firmed solar photovoltaics (PV) and wind compared to LNG are another leading indicator of potential demand destruction. BloombergNEF's analysis indicates that solar paired with battery storage is becoming increasingly cost-competitive with gas-fired generation.[109] Wood Mackenzie's 2026 analysis finds four-hour battery storage is now cheaper than gas peaking plants in all 43 markets where both were modelled, and single-axis tracking solar the cheapest new-build technology in 43 of 48.[110] In Australia, CSIRO and AEMO's GenCost analysis similarly finds that wind and solar backed by storage and transmission remain the lowest-cost option for new electricity generation.[111]

[103] IEA (2025c, 2026c).
[104] Reuters (2026).
[105] Talberg et al. (2026b).
[106] Xiong (2026).
[107] US EIA (2026b).
[108] Focus Taiwan (2026); Pattaya Mail (2026).
[109] BloombergNEF (2025).
[110] Wood Mackenzie (2026b).
[111] Graham et al. (2025).

Contracting behaviour since the disruption began is not evidence that demand destruction has or has not occurred, but it can be an early signal of how sellers and buyers are behaving while it plays out. The analysis above captures this only in part, using the LNG contract database described in Appendix A2 and incorporating publicly disclosed changes through October 2026 where these could be reconciled with the register and assigned delivery dates. A review of publicly disclosed LNG contract changes between January and October 2026 gives a picture of how sellers are behaving in real time (Appendix A3, Figure A3-1). That contracting behaviour does not appear to change the story. Of the 42 changes disclosed in that period, 39 Mtpa changed hands and only 4 Mtpa of it was contracts ending. The activity sits on the sellers' side and mainly with portfolio players, as new and expanding North American projects sold flexible, multi-source supply rather than tying one project to one buyer. It involves Australia's competitors, not Australia. The only changes with Australian companies are a 1 Mtpa non-binding heads of agreement by Santos for Canadian gas, a 0.2 Mtpa Woodside sale to JERA and a sale of up to 3 Mtpa of United States LNG from Woodside's Louisiana LNG project to QatarEnergy, none of them a new long-term Australian export commitment. None of it suggests the Hormuz Strait disruption has moved the contract-cliff timeline set out in this analysis. Middle East disruption could lead some Asian buyers to pay a premium for supply from outside the Gulf, which would favour Australian LNG given its proximity. The contract changes disclosed to October 2026 do not yet show this. The producers building their books in 2026 are doing it through flexible, low-cost portfolio positioning that Australia, as a high-cost producer, is poorly placed to match.

Data centres are not game changers globally

Data centres are frequently framed as a wildcard for electricity and therefore gas demand. However, the scale involved does not currently support that framing for this analysis. The IEA's Energy and AI 2025 sensitivity analysis puts global data centre electricity consumption at only around 1.5% of global electricity consumption in 2024 (415 terawatt-hours, TWh), rising to about 3% by 2030 in its Base case (Figure A8-1). Even in its most demand-intensive case, the share of electricity for data centres does not reshape the 2035 picture (Appendix A8, Figure A8-2).

Australian gas and LNG exit between 2037 and 2049

Australia's domestic gas use was about 1,015 PJ in 2024–25 (Figure 22).[112] That excludes the roughly 438 PJ the LNG plants burned themselves, mostly to power liquefaction, which this report counts with exports.[113] Domestic use supplied three markets of very different shape (Figure 17). On the east coast, domestic customers used about 494 PJ in 2025: industry 46%, homes and businesses 34% and gas-fired power stations 20%.[114] Western Australia's domestic market, about 380 PJ, is dominated by mining, minerals processing (alumina in particular) and power generation.[115] The Northern Territory's market is small, and mostly supplies power.[116]

[112] DCCEEW (2026b), Tables A and C.
[113] DCCEEW (2026c), p. 10.
[114] AEMO (2026a), Tables 16, 17 and 19.
[115] AEMO (2025), section 2.3.
[116] AEMO (2026a); DCCEEW (2026b), Table C.

Under the 1.5°C pathways, domestic gas use declines more slowly than coal. On the median pathway it holds near today's level to 2030, then falls by about a third by 2040 and by three-quarters by 2050. It drops below 20% of 2025 use in 2056 (Figure 22), where the gas networks stop being viable, and then flattens at around 15% of today's use for the rest of the century. The early decline is gentle because gas has uses that are harder to replace quickly than coal-fired power. These include high-temperature industrial heat, chemical feedstock for ammonia and other products, and firming the electricity grid when renewable output is low.

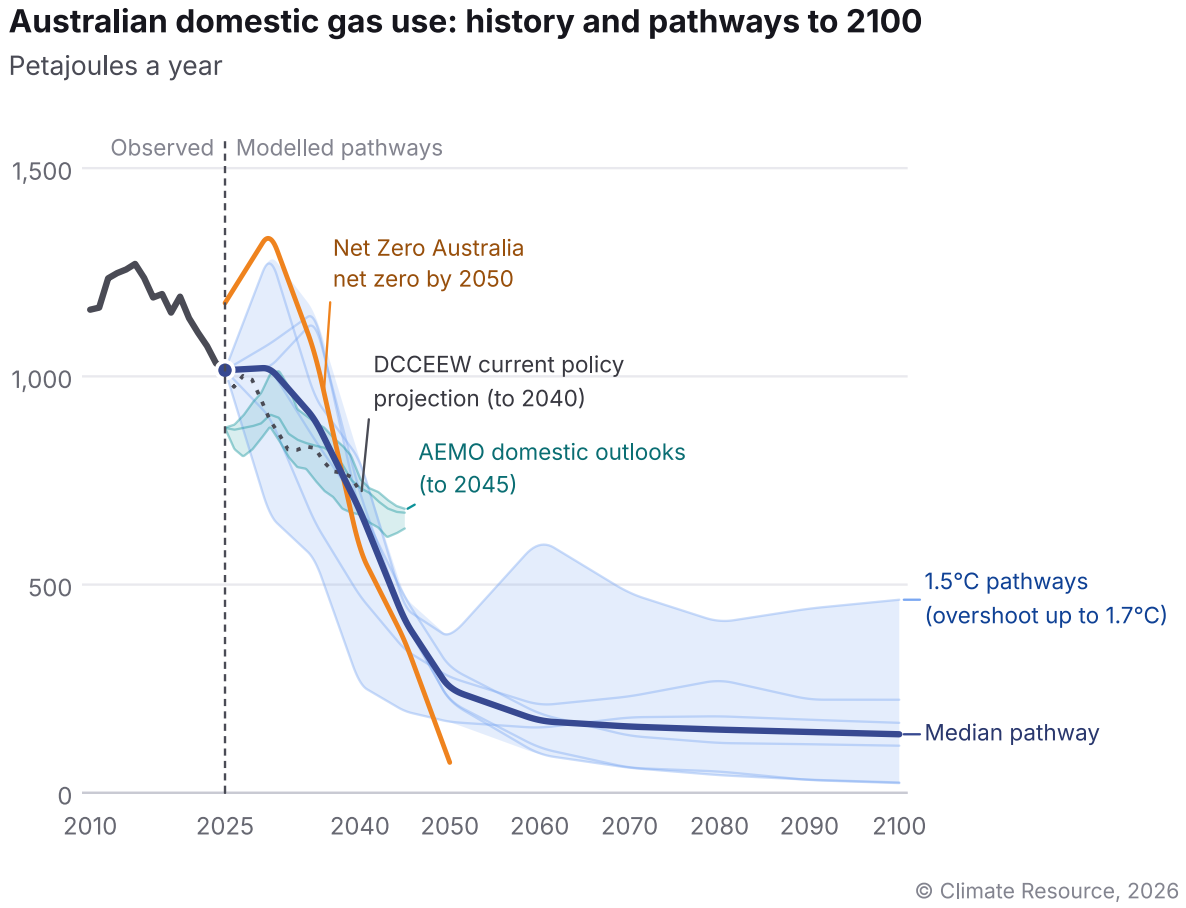


Figure 22: Australian domestic gas use, 2010 to 2100 (PJ per year), excluding the gas the LNG plants burn: observed use, the six lowest-overshoot pathways for Australia and New Zealand scaled to FY2025, Net Zero Australia and the DCCEEW projection less LNG plant fuel, and AEMO's domestic outlooks, fossil gas only. Source: DCCEEW; Net Zero Australia; AEMO; ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

Figure 22 shows that Australian projections differ in the timing and pace of the decline. AEMO's domestic gas outlooks, counted as fossil gas only, broadly follow the median pathway to the mid-2030s, then decline more slowly and begin to flatten after 2040: by 2045 all three scenarios sit at 635 to 682 PJ, against a median of about 410 PJ, because AEMO assumes industrial gas use holds up while homes and power stations leave gas.[117] Net Zero Australia's net zero by 2050 scenario rises to the early 2030s, to supply industry and new

[117] AEMO (2026a) and AEMO (2025), scenario demand to 2045, as published for the covered domestic markets (876 PJ in 2025 against 1,015 PJ of total domestic use excluding LNG plant fuel); Climate Resource compilation (Figure 22). AEMO forecasts gas delivered to customers in its covered markets, by calendar year; the AES is a gross primary supply balance by financial year, including off-grid generation, own use, losses and statistical differences. That scope difference is why the AEMO lines start about 139 PJ below the observed series. Accelerated Transition is shown less the dedicated hydrogen AEMO forecasts for green commodities (2026 GSOO Figure 16; 179 PJ by 2045), so all three lines are fossil gas.

exports, then falls steeply, crossing the median pathway around 2040 and reaching below 100 PJ by 2050.[118] DCCEEW's current policy projection, with the plant fuel removed on the same basis, reaches about 720 PJ in 2040, close to the median pathway's 680 PJ, but it stops in 2040, before the pathways' steepest decline.[119]

Most of the decline in gas use reflects demand that disappears as buildings and industrial heat are electrified and gas-fired generation is replaced by renewables and storage. Substitutes play a smaller part through mid-century. In a separate median comparison of the same six pathways, including LNG plant fuel, fossil gas with carbon capture peaks at about 10% of 2025 use, and non-fossil hydrogen is already around 6% of 2025 use by 2040.

Data centres add a new source of electricity demand, but on current projections they do not change this picture. AEMO expects data centres in the National Electricity Market to use about 34 TWh a year by 2035–36 under its Step Change scenario, about 13% of operational consumption, up from around 5 TWh in 2025–26.[120] Its 2026 ISP finds that higher demand from data centres and other large loads calls for more generation and storage, without changing the overall development path. Within the electricity system, gas power stations increasingly run only to cover periods of low renewable output and peak demand, so they burn relatively little gas even as total electricity demand grows.

Gas's exit years are measured, like coal's, on use and exports together. They open in 2037, as existing LNG contracts run out, and close in 2049, when use and exports together, by then domestic use alone, fall below 5% of the 2024 total. The 80% and 95% thresholds are conventions, applied the same way to every fuel, not a modelled point at which the industry stops being viable. Domestic use is then still about a quarter of its 2024 level; it falls below 20% in 2056, the point at which the networks stop being viable. Evidence from Australia's gas networks shows why that level matters (Table 4).

[118] Net Zero Australia (2025).
[119] DCCEEW (2025a), p. 60.
[120] AEMO (2026c).

Table 4: What forecasters, regulators and network owners expect as domestic gas use falls. Source: AEMC (2026); ACT Government (2022, 2026); Evoenergy (2025); AER (2024, 2025); Dynamic Analysis (2024); AEMO (2026a); Reeve et al. (2026); GPA Engineering (2026); Climate Resource analysis.

Share of today's network gas use remaining	What the evidence shows
About 70 to 75%	Bills reach the point where customers start to switch away and a disorderly exit begins.[121] The ACT expects parts of its network to become unviable from the mid-2030s.[122]
About 50%	Network bills roughly double.[123]
About 20%	The point at which planners already assume the system ends. AEMO's Step Change has residential and small business gas at 35 PJ by 2045; the AER's Jemena modelling assumes demand at 21% of today's by 2050, with bills up 500–600%; the ACT plans to decommission its whole network in 2045.[124]
5 to 10% or less	Gas becomes a niche fuel, kept only for a few essential uses that are hard to replace.[125] In the ACT, less than 1% of network demand is significantly difficult or impossible to electrify.[126]

Much of the cost of supplying homes and small businesses is fixed in pipelines and distribution networks, so as demand falls those costs are shared among fewer customers, prices rise and more customers leave. Network studies find this happening well before demand reaches zero, and planners already assume networks close at around a fifth of today's use. Large industrial users on transmission pipelines or dedicated supply face different economics, and some may be served for longer. Domestic use here excludes the gas the LNG plants burn, which this report counts with exports.

Australia's gas industry looks different after 2035

Today, about three-quarters of the gas Australia produces is exported as LNG.[127] In 2024–25 that was about 79 Mt of LNG, around 4,400 PJ, against about 1,015 PJ used at home and a further 438 PJ burned by the LNG plants themselves.[128] Under the scenario that we present here, the balance reverses within little more than a decade. LNG contracts begin to fall away after 2028 and decline steeply between 2035 and 2037. Over the same period, domestic use falls by about a fifth. By the late 2030s, most Australian gas would be produced for Australian users (Figure 23).

[121] AEMC (2026), p. 9; Reeve et al. (2026), p. 39.
[122] ACT Government (2022), p. 18; ACT Government (2026), p. 14; Evoenergy (2025), p. 5.
[123] AER (2024), pp. 14–16; Dynamic Analysis (2024), p. 3.
[124] AEMO (2026a), p. 32; AER (2024), p. 15; AER (2025), p. 214; ACT Government (2026), p. 14.
[125] Reeve et al. (2026), p. 3.
[126] GPA Engineering (2026), p. 3.
[127] DCCEEW (2026b), Tables A and N.
[128] DCCEEW (2026b), Tables A and N; DCCEEW (2026c), pp. 9–10.

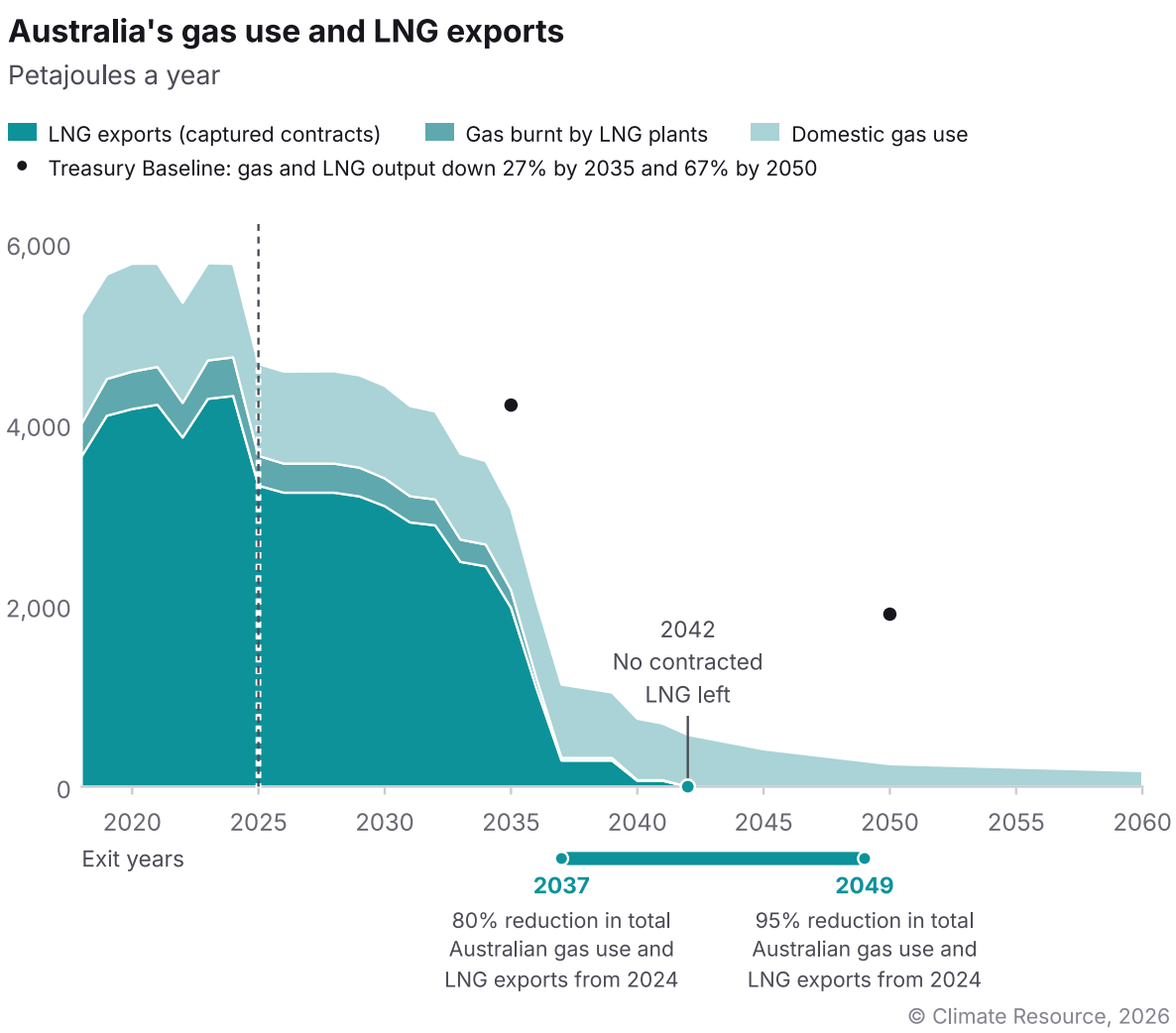


Figure 23: Australia's gas use and LNG exports, 2018 to 2060 (PJ per year): LNG exports observed, then the existing contracts, the gas the LNG plants burn, and domestic use observed, then the median lowest-overshoot pathway. A label marks 2042, when contracted deliveries end; the bar under the axis marks gas's exit years, 2037 to 2049, an 80% and a 95% reduction in use and exports together; marks show Treasury's Baseline. Source: DCCEEW (2026b); Treasury (2025); ScenarioMIP-CMIP7 lowest-overshoot pathways; LNG contract database (Appendix A2); Climate Resource analysis.

The turning point comes earliest on the east coast. Queensland's LNG contracts all end by 2036.[129] Without new contracts, east coast gas production would then serve only the domestic market, about a quarter of what the region produces today. The Northern Territory's contracts end in 2035. Western Australia's run longest with Gorgon's deliveries to Japanese buyers running to 2039, and to India's Petronet to 2041 (Table 5).

[129] Talberg et al. (2026b); LNG contract database (Appendix A2).

Table 5: Australia's three gas markets today and after their LNG contracts end. Source: AEMO (2026a, 2025); DCCEEW (2026b); LNG contract database (Appendix A2); Climate Resource analysis.

Market	Today	After LNG contracts end
East coast (Queensland, NSW, Victoria, SA, Tasmania, ACT)	About 1,920 PJ produced, around 75% exported through Curtis Island; Bass Strait fields in decline	From 2037, in the no-renewal/no-spot-sales scenario, production serves the shrinking domestic market alone
Western Australia	Most of Australia's LNG; domestic supply largely from LNG projects under the state's reservation policy	From 2042, domestic supply has to stand on its own, without export volumes to share the cost of fields and processing
Northern Territory	Darwin LNG and Ichthys; small local market	From 2036, after the last contracts end, only the small domestic market remains in this scenario

Three questions arise from this:

1. What sets domestic gas prices once exports end? Since the Curtis Island plants started up, east coast wholesale prices have tracked what gas could earn as LNG.[130] Without export contracts, prices would depend instead on the cost of supplying the domestic market alone. Would that bring prices below export parity, or push them higher as fixed costs are spread over smaller volumes?
2. Does domestic supply tighten as export-scale infrastructure becomes uneconomic? Much of the east coast's gas comes from coal seam gas fields in the Surat and Bowen basins, which need continuous drilling to sustain output. Those fields, and the pipelines that carry their gas to southern markets, were built to supply export plants several times the size of the domestic market. As export volumes decline, domestic users alone cannot carry the cost of keeping systems running. This is the same fixed-cost problem behind the 20% threshold for distribution networks, applied here to supply.
3. What replaces reservation policies built around LNG? The proposed national reservation scheme requires LNG exporters to supply the domestic market in proportion to their exports, and Western Australia's policy works the same way. Both rely on a large export industry to draw on. When exports end, domestic supply may also be at risk. Prudent policy recognises and plans for this risk.

Gas's exit years are set by exports at one end and domestic demand at the other. They begin in 2037, as the existing LNG contracts are running down (the contracts reach zero in 2042), and run to 2049, when use and exports together, by then domestic use alone, fall below 5% of the 2024 total. Domestic use is then still about a quarter of today's level and does not fall below 20%, where the networks stop being viable, until 2056. For gas, unlike

[130] ACCC (2026a, 2026b).

coal, the exit years run on for seven years after the export contracts end, and the domestic decline continues well beyond them. That tail is driven by the domestic market. There are time-critical policy implications of this (Box 3)

As for coal, these exit years assume the supply system keeps running until demand has gone. The questions above suggest it may not. If the cost of supplying a shrinking domestic market from export-scale infrastructure rises faster than demand falls, parts of the system could close earlier than the pathway alone implies. As users leave, there will be pressure to shift the fixed costs of pipelines and networks onto taxpayers or the customers who remain.

Box 3: The shrinking window of LNG revenue

The 2042 date sharpens the case for taxing LNG exports sooner rather than later. In a 1.5°C world, deliveries under existing contracts fall steeply from 2035 and reach zero in 2042.[131] That means that most of the LNG Australia is likely to sell will be shipped in the next decade, while earnings are high. DISR forecasts $70 billion in 2026–27.[132]

The Petroleum Resource Rent Tax applies to profits only once a project has recovered its costs, so most LNG projects were not expected to pay it until the 2030s.[133] An export levy is charged on what is shipped, from the first cargo. Industry argues that a 25% export levy would put up to 20,000 PJ of planned new gas production at risk.[134] In a 1.5°C world that new production would find little uncontracted demand to serve in any case. This report does not model the fiscal effects of either tax. What it adds is timing. Revenue not collected while the contracts run cannot be collected after they end.

[131] Climate Resource analysis of the LNG contract database described in Appendix A2; see Figure 20.
[132] DISR (2026c).
[133] Chalmers and King (2023).
[134] Wood Mackenzie (2026a).

What does 1.5°C imply for Australian oil use?

Australia exports most of the oil it produces and imports most of the oil it uses (Figure 24).

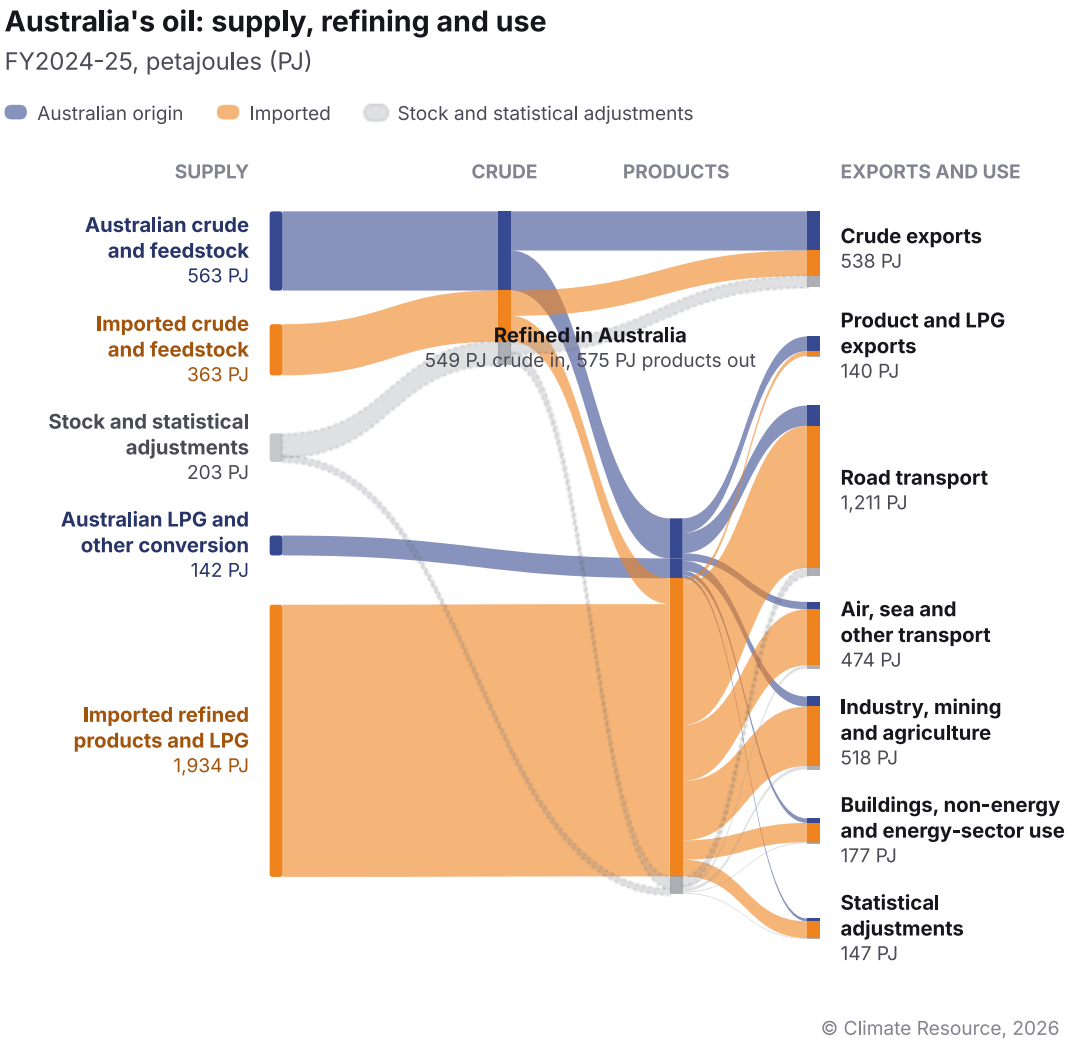


Figure 24: Australia's oil supply, refining and use, FY2024–25 (PJ): supply by origin through the crude and product pools to exports and uses; ribbons are proportional estimates, not observed routes. Ribbon colours do not reproduce the refinery feed split (about 80% imported crude). Source: DCCEEW (2026b, 2026d); Climate Resource analysis.

In 2024–25 Australia produced about 15 GL of crude oil and condensate and exported 96% of it. Much of the condensate is stripped from gas on its way to the LNG plants. Of the 62 GL of refined fuel sold in Australia, 52 GL (83%) arrived already refined and about 10 GL came from the two refineries, Ampol's Lytton in Brisbane and Viva Energy's Geelong. The refineries made 14 GL in all, the rest going to product exports, bunkers and stock changes, and ran about 80% imported crude. Counting both routes, more than 90% of the liquid fuel Australia used came from abroad. In August 2026, stocks held in Australia covered about 52 days of net imports, against the IEA's 90-day obligation.[135] However, production is falling. The Office of the Chief Economist expects crude and condensate output to fall from about 263,000 barrels a day in 2024–25 to 170,000 by 2030–31, as fields in the Carnarvon Basin

[135] DCCEEW (2026d).

near the end of their lives.[136] With no new oil fields due to come online, reliance on imported fuel will grow whatever happens to demand.

As primary energy, Australia used about 2,350 PJ of oil in 2024–25, including fuel sold to international aircraft and ships. This is the base year for the pathways. Petrol and diesel for cars and trucks, and diesel for mining, take most of it. Petrol use has been falling for some time, while diesel use has kept rising, and mining now takes about a quarter of it.[137] Coal mining alone used about 3.9 billion litres in 2023–24, around 150 PJ. At open-cut mines, deeper pits and rising strip ratios mean more overburden to move for each tonne of coal, so every major coal miner now burns more diesel per tonne than it did in 2020–21.[138] As coal output falls in the 2030s, that diesel demand falls with it. Aviation, shipping, industry and non-energy uses such as bitumen and lubricants account for the rest.[139]

Oil use exits between 2050 and 2067 as electricity replaces it

Under the 1.5°C pathways, Australian oil use falls more slowly than coal but faster than gas (Figure 25).

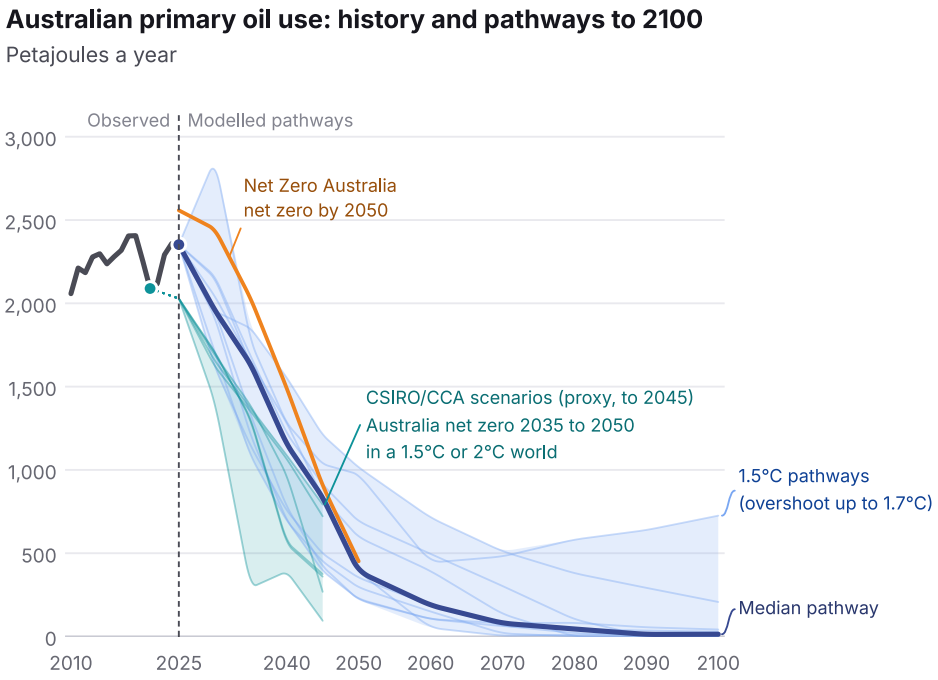


Figure 25: Australian primary oil use, 2010 to 2100 (PJ per year): observed use including international bunkers, the lowest-overshoot pathways scaled to FY2025. Net Zero Australia as published, and CSIRO/CCA converted to a primary-energy estimate (Appendix A6). Source: DCCEEW (2026b); CSIRO/CCA; Net Zero Australia; ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

[136] Argus Media (2026).

[137] DCCEEW (2026d), sales by product; Saunders et al. (2026). Mining used almost 8 billion litres in 2023–24, a quarter of the national total.

[138] Gorringe (2026).

[139] DCCEEW (2026b), Tables A and C.

Nine modelled pathways have usable oil data. Their median reaches about 17% of today's use by 2050, and the pathways span roughly 220 to 1,000 PJ in that year. The median falls below 20% in 2050, 10% in 2058 and 5% in 2067, so oil's exit years are 2050 to 2067. Cars, vans and buses electrify first, then freight trucks. Road transport may electrify sooner than the pathways assume. Australia's electric car sales roughly doubled in March to June 2026 compared with a year earlier, after petrol prices jumped by about a third.[140] Aviation, shipping, mining diesel and chemical feedstocks hold on longest.

With no alternative yet to jet engines on long-haul flights, jet fuel is likely to be the last to go; its main replacements are biofuels and synthetic fuels rather than electricity. Mining diesel may move sooner than the pathways assume. Fortescue has ordered 360 battery-electric haul trucks for its Pilbara iron ore operations, as part of a plan to decarbonise them by 2030.[141]

To check that the global models translate sensibly to Australia, Figure 25 also shows two Australian bottom-up studies. The green plume is the CSIRO and Climate Change Authority (CCA) scenarios, in which Australia reaches net zero between 2035 and 2050 in a 1.5°C or 2°C world.[142] The orange line is Net Zero Australia's net zero by 2050 scenario.[143] Both fall within the range of the 1.5°C pathways. The CSIRO/CCA scenarios sit at or below the median to 2045, and NZA tracks just above it to 2050. So the pathways' oil decline is consistent with detailed Australian sector modelling, allowing for differences in how each study draws its boundary.

Oil's exit years are measured on domestic use alone, because oil exports are minimal and therefore outside the scope of this analysis. Over those years the supply chain thins from the top down. Petrol stations thin out as cars electrify and the import terminals and trucks that remain can still serve a small residual market, increasingly with non-fossil liquids.

Most of what replaces oil is electricity, so the liquid fuel market itself shrinks. Within what remains, biofuels and synthetic fuels made from renewable hydrogen overtake fossil oil in the early 2050s. By 2067 the oil that remains is used mostly in industry (Figure 26). About 5% of today's oil is still delivered to Australian users. Just under four-fifths of that is burned domestically: nearly half of what remains goes to industry, about a fifth to road, rail and domestic shipping together, and about an eighth to domestic aviation. Roughly a fifth is non-energy use such as bitumen, lubricants and petrochemical feedstock.

[140] IEA (2026a).
[141] Reuters (2024).
[142] CSIRO (2025).
[143] Net Zero Australia (2025).

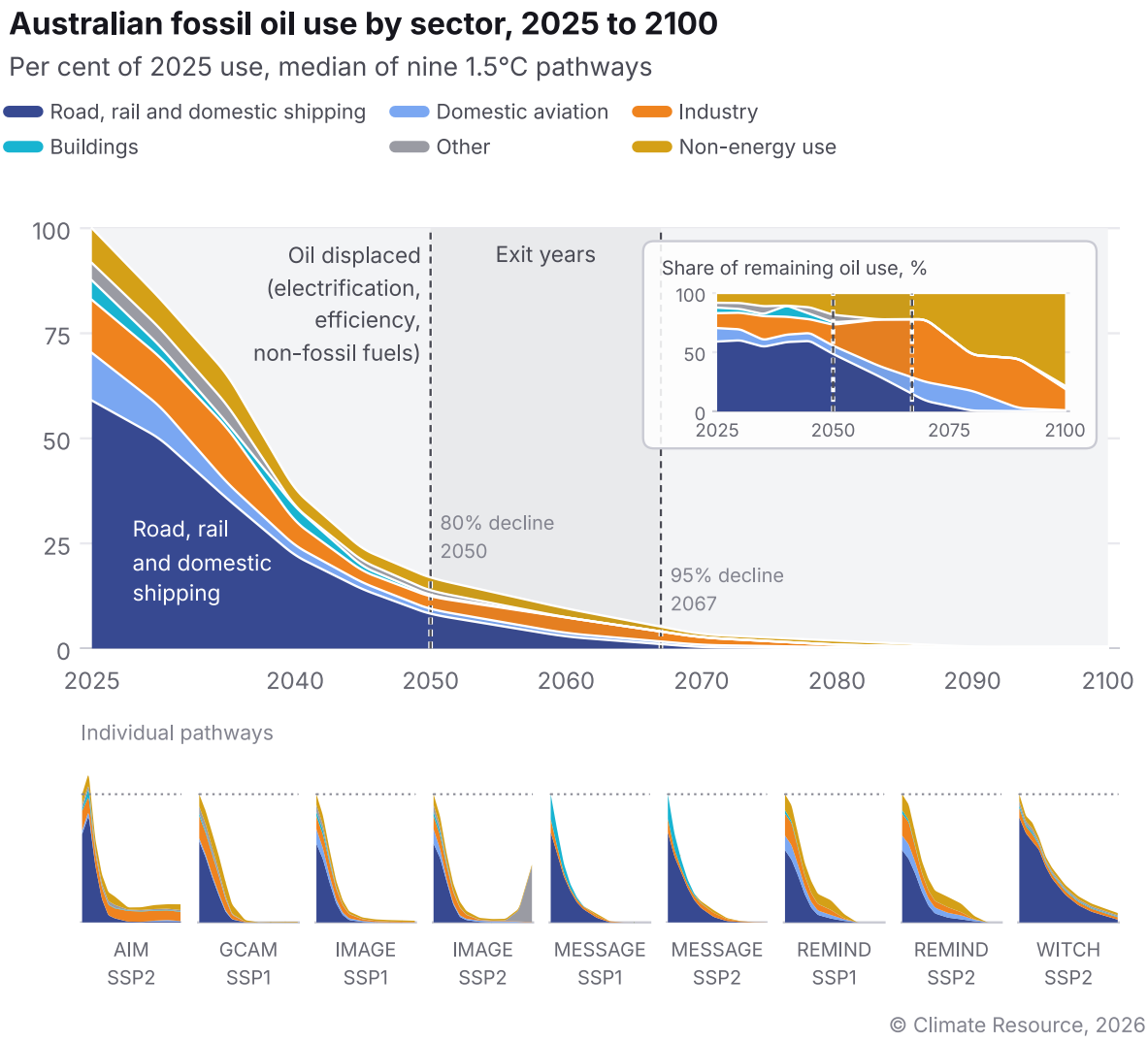


Figure 26: Australian fossil oil use by end-use sector, 2025 to 2100 (per cent of 2025 use, median of the lowest-overshoot pathways; each pathway below), excluding international aviation and shipping. The shading marks oil's exit years, taken from primary oil use; the inset shows each sector's share of what remains. Method: Appendix A6. Source: ScenarioMIP-CMIP7 lowest-overshoot pathways; Climate Resource analysis.

For oil, the exit years are about Australian use, not production. Most crude and condensate is exported, and condensate output is tied to LNG (almost three quarters of Australia's extracted oil is condensate and LPG associated with producing gas fields) so production follows the gas timeline. The domestic industry these years affect is fuel supply. That means the two refineries, which depend on domestic sales and fuel security support, and the import terminals and distribution chain that bring in most of the country's fuel. With no network that can stop paying for itself, the phase-out will play out through refining and fuel security policy..

The outlook for the Australian fossil fuel industry

Exports and domestic use set the pace at which Australia's fossil fuel industry winds down, fuel by fuel and state by state (Figure 27).

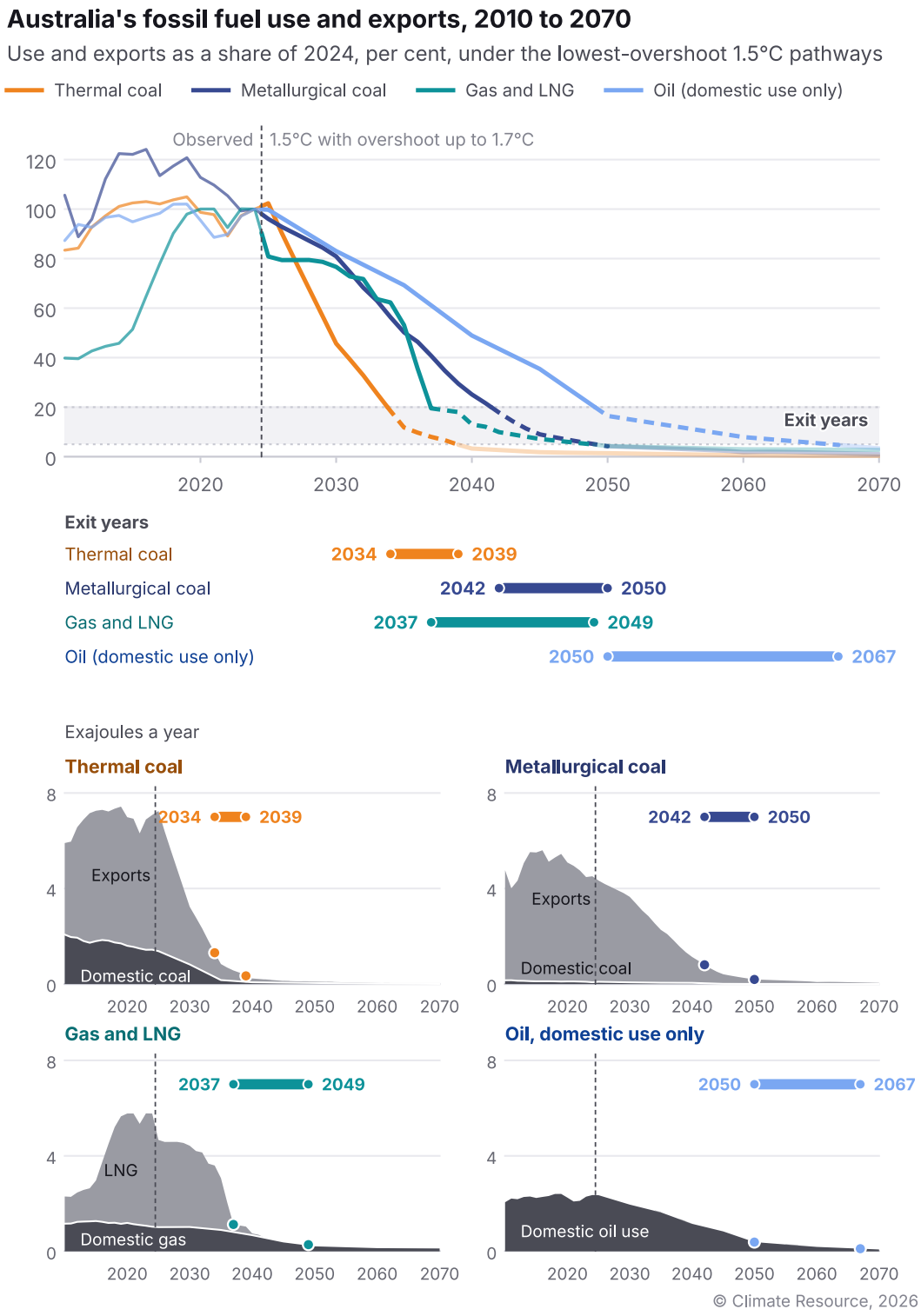


Figure 27: Australia's fossil fuel use and exports, 2010 to 2070: domestic use and exports together as a share of 2024 (top) and by fuel in EJ (below). The band and the strip mark each fuel's exit years. Source: DCCEEW (2026b); DISR; CEPII BACI; ScenarioMIP-CMIP7 lowest-overshoot pathways; LNG contract database (Appendix A2); Climate Resource analysis.

In 2024 Australia's fossil fuel industry handled about 19.7 EJ of energy. Exports and the gas burned by LNG plants accounted for about three-quarters of that total (14.8 EJ), with the remaining 4.9 EJ used domestically. On the lowest-overshoot pathways and the existing LNG contracts, that total falls to about 5% of its 2024 level by 2050 and to about 1.5% by 2070.

The timelines depend on each fuel's market. Coal is an export industry, so exports set its exit years: thermal coal's are 2034 to 2039, with domestic use a year or two behind, and metallurgical coal's 2042 to 2050. Gas's exit years are 2037 to 2049: the existing LNG contracts run out in 2042, and domestic gas use, still a quarter of today's level in 2049, stays above 20% until 2056. Oil, which Australia mostly imports, exits between 2050 and 2067. In short, exports go first and Australia's own use of gas and oil goes last.

Table 6: Each fuel's exit years and what happens in them

Fuel	80% decline	95% decline	What happens
Thermal coal Domestic plus exports	2034	2039	Export customers go first and domestic power stations close in the same decade. The shared rail and port systems run at a fifth of their design volume and their fixed costs fall on the mines that remain, raising delivered costs; what is left below 5%, about 10 Mt a year, is one large mine's output.
Metallurgical coal Domestic plus exports	2042	2050	Export customers decide the pace as overseas steelmaking decarbonises. The Bowen Basin's shared rail and port systems face the same fixed-cost squeeze once thermal coal has gone; what is left below 5%, about 8 Mt a year, is one large mine's output.
Gas Domestic plus exports	2037	2049	LNG exports end first, so fields and pipelines built for export must be carried by Australian users alone. As households and businesses electrify, network bills roughly double at about half of today's use and the networks stop being viable at about a fifth, in 2056, seven years after gas's exit years end (Table 4).
LNG exports Existing contracts only	–	2042	Deliveries fall steeply from 2035 as the Northern Territory's and Queensland's contracts end, and in an oversupplied market no new contracts replace them. Most of the revenue still to be earned from LNG falls in the next decade.
Oil Domestic only	2050	2067	Refining ends first, by policy. Petrol stations thin out as cars electrify, and the import terminals and trucks that remain carry a shrinking, dearer residual, increasingly non-fossil liquids.

The same dates land differently across the country:

- **New South Wales** is exposed to thermal coal from both directions. Its exports are almost all thermal and fall below 20% of 2024 volumes from 2034 and below 5% from 2039, and its remaining coal power stations close by 2040, Mt Piper last. Its export systems are also the most likely to close before demand alone would require.
- **Queensland** has the longest runway, through metallurgical coal to 2050. Its LNG contracts end by 2036, though, and its state-owned coal power stations are scheduled to run into the 2040s, well after the pathway has domestic thermal coal use below 5%.

- **Western Australia and the Northern Territory** are LNG economies. The Territory's contracts end by 2035. Western Australia's run to 2042 and are the last in the national contracts. After that, Western Australia's domestic gas, largely supplied by the LNG projects under the state's reservation policy, has to stand on its own as demand declines towards 2056. Its coal power comes down to Bluewaters, which has no closure date.
- **Victoria's** brown coal ends with its power stations: Yallourn in 2028, Loy Yang A in 2035 and Loy Yang B in 2047. Its gas use, like South Australia's and Tasmania's, follows the national path.

Figure 28 isolates the export timelines.

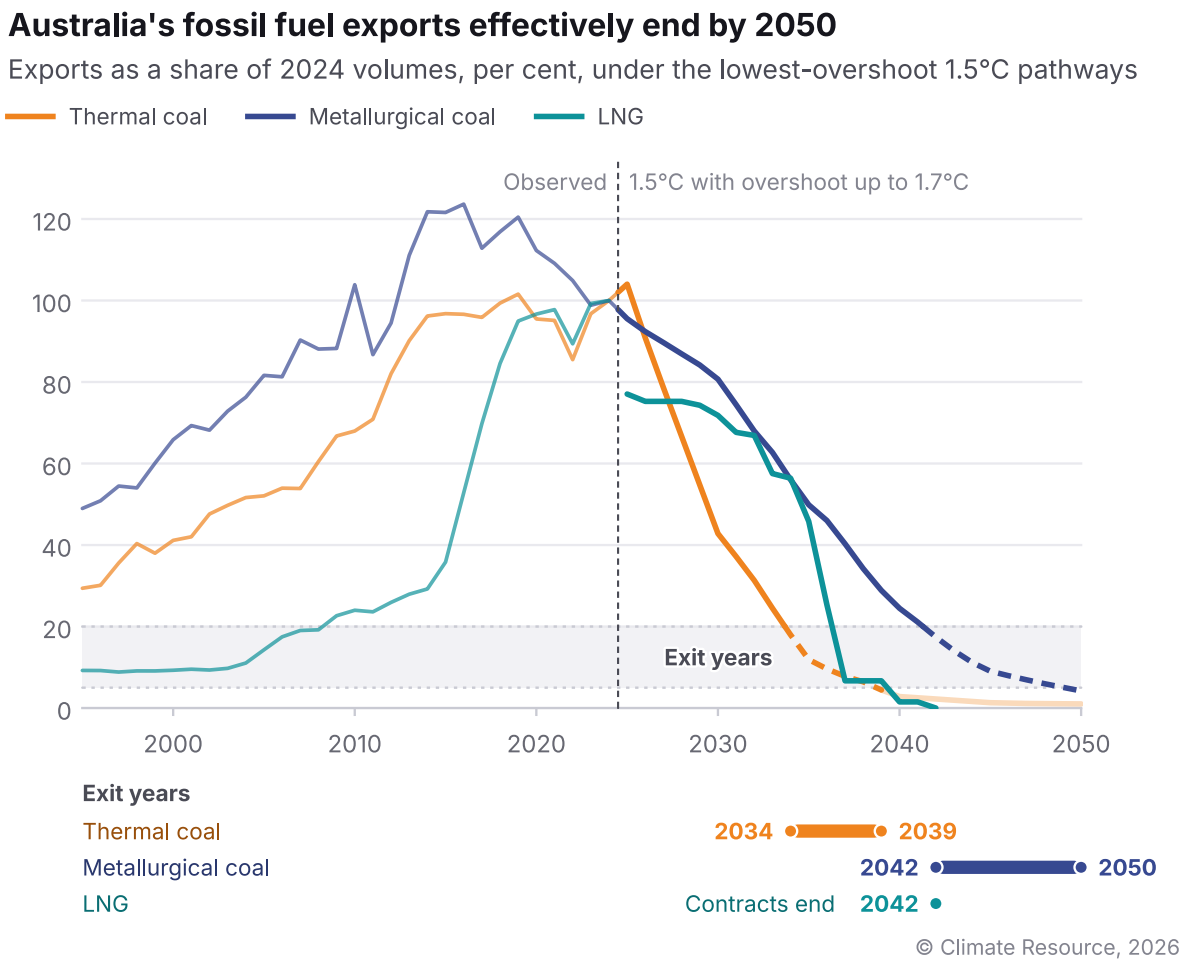


Figure 28: Australia's thermal coal, metallurgical coal and LNG exports as a share of 2024 volumes, observed from 1995 and outlook to 2050 (per cent): coal follows the lowest-overshoot pathways, with its exit years shaded and dated in the strip; LNG is existing contracts only, ending in 2042. Scenario based, not forecasts. Source: DISR; CEPII BACI; Eurostat; ScenarioMIP-CMIP7 lowest-overshoot pathways; LNG contract database (Appendix A2); Climate Resource analysis.[144]

[144]Coal's exit years run from the first year exports stay below 20% of 2024 volumes to the first year they stay below 5%; LNG's end when the existing contracts end.

Our results are steeper and earlier than the Australian Government's, but are close to Climate Analytics' on coal by a different route (Appendix A7):

- The Future Gas Strategy's most ambitious scenario, the IEA's Net Zero Emissions by 2050, has LNG exports falling from 81 Mt in 2022–23 to 7 Mt by 2050, eight years after the existing LNG contracts expire.[145]
- Treasury's Baseline has coal output, thermal and metallurgical combined, 47% below 2025 by 2035 and 72% by 2050 (the marks on Figure 13). We find coal exports 72% below 2024 by 2035 and 98% by 2050.[146]
- Climate Analytics finds coal exports down 95% by 2040, against 88% here, but LNG still at 7 Mt in 2050.[147] Its coal result comes from a single model, REMIND, which phases coal out faster than most. In our ensemble, REMIND's two runs cut global coal use to 10–11% of 2020 levels by 2040 and 1% by 2050, against a median of 15% and 5%.[148]

Climate ambition explains only part of the differences. Our pathways, the IEA's Net Zero scenario and Climate Analytics' Highest Possible Ambition pathway all peak at about 1.6–1.7°C and return towards or below 1.5°C by 2100. Treasury's 'well below 2°C' assumption is less ambitious, which explains part of the gap with Treasury but none of the gap with the other two. The rest comes from the trade lens: what is left of the LNG market once signed contracts are counted, and what is left of the coal market once importers' own mines are counted.

[145] DISR (2024), p. 49.

[146] Treasury (2025), p. 11, footnote 1 (climate framework), and p. 33, Table 4.1 (output changes from 2025).

[147] Houlie et al. (2026); Climate Analytics (2026).

[148] Minx et al. (2024).

Conclusions

This analysis explored when Australia's fossil fuel industry phases out if the world follows the most ambitious 1.5°C pathways that remain plausible.

It is not a forecast, and it is only one input into a wider conversation. The pathways trace the least-cost global route to 1.5°C and leave aside questions of equity and justice, such as which countries should move first and who should pay.

What they show is that each fuel exits over a span of years, from an 80% to a 95% decline in its use: thermal coal from 2034 to 2039, metallurgical coal from 2042 to 2050, gas from 2037 to 2049 (LNG exports gone by 2042) and oil from 2050 to 2067. Those years fall within the working life of people employed in the industry today, and within the payback period of projects being proposed now. That makes them a planning question for this decade.

The exit years mark when customers stop needing Australian coal and LNG, and when Australia's own use falls to a residual. Parts of the industry could end sooner, within or before those years. Shared rail, port and pipeline systems can stop paying their way before the last customer goes. Nobody can say exactly when those points arrive, and that uncertainty is a strong argument for planning. A planned exit can be sequenced around workers, regions and the supply chains that domestic users share with exporters. An exit left to markets will be decided project by project, and may reach a region as a closure notice. Or it may end in calls for a bail-out. With the timing set out here, any rescue would be a failure of planning in the face of the evidence.

On these pathways, the majority of the coal and LNG that Australia will export from here is shipped before 2040. How the resource is taxed in that window, whether new supply is approved, and how the proceeds are used will decide what Australia has to show for the industry when it ends. Revenue not collected while contracts run cannot be collected afterwards. New supply would enter a market where uncontracted capacity already dwarfs uncontracted demand.

Fossil fuel exports earned $149 billion in 2024–25, much of it in a handful of regions. A phase-out plan without a phase-in plan only manages decline. What replaces this industry is beyond the scope of this report, but the replacement has to be measured in tens of billions of dollars a year.

On the east coast, the end of LNG contracts by 2036 raises questions about gas prices, the cost of export-scale infrastructure and the future of reservation policy. Western Australia faces the same questions by the early 2040s. Projections of domestic coal and gas supply, and the plans built on them, should be tested against these export timelines. The economics this report has not modelled are the next things to test. They include shared coal systems, sustaining contracted LNG, and supplying a residual domestic gas market, and a warmer, well-below-2°C case for coal, like the one tested for LNG, would show how far the coal dates move.

The dates here are set against the world's highest plausible ambition, not its current policies, and that is deliberate. In ten years, projected warming under the world's commitments has fallen by about a degree. If it moves again, today's central case will look as dated as 2015's does now. Planning to these dates protects Australia against being overtaken by its customers' ambition, and by its own. Setting no date is also a choice, but it leaves the timing to other countries' decisions and the cost to the regions least able to carry it.

References

ABS (2022). 2021 Census of Population and Housing: QuickStats, Isaac, Singleton, Muswellbrook and Central Highlands. Australian Bureau of Statistics, Canberra, 28 June 2022.

ACCC (2026a). Gas inquiry 2017–2030: June 2026 interim report. Australian Competition and Consumer Commission, Canberra, 10 July 2026.

ACCC (2026b). LNG netback price series. Australian Competition and Consumer Commission.

ACT Government (2022). Powering Canberra: our pathway to electrification, position paper. ACT Government, Canberra, August 2022.

ACT Government (2026). Future appliance regulations to support the gas transition: discussion paper. ACT Government, Canberra, August 2026.

AEMC (2026). Gas networks in transition: directions paper, National Gas Amendment (Gas Networks in Transition) Rule, GRC0082. Australian Energy Market Commission, 19 March 2026.

AEMO (2025). 2025 Western Australia Gas Statement of Opportunities. Australian Energy Market Operator, December 2025.

AEMO (2026a). 2026 Gas Statement of Opportunities. Australian Energy Market Operator, Melbourne, March 2026.

AEMO (2026b). 2026 Integrated System Plan. Australian Energy Market Operator, Melbourne, June 2026.

AEMO (2026c). Forecasting growing data centre demand: 2026 Electricity Statement of Opportunities explainer. Australian Energy Market Operator, August 2026.

AEMO (2026d). Generating Unit Expected Closure Year. Australian Energy Market Operator, October 2026.

AER (2024). Draft decision: Jemena Gas Networks (NSW) access arrangement 2025–30, Attachment 4: regulatory depreciation. Australian Energy Regulator, November 2024.

AER (2025). State of the energy market 2025. Australian Energy Regulator.

Argus Media (2020). Australian met coal exports slip back in October. Argus Media.

Argus Media (2024). Australia’s Dec coking coal exports at six-month high. Argus Media.

Argus Media (2026). Australia's OCE cuts FY2026-27 crude output projection. Argus Media, Sydney, 6 July 2026.

Australian Government (2015). Australia's Intended Nationally Determined Contribution to a new Climate Change Agreement. Submitted to the UNFCCC, August 2015.

Australian Government (2022). Australia's Nationally Determined Contribution: Communication 2022. Submitted to the UNFCCC, 16 June 2022.

Australian Government (2025). Australia's 2035 Nationally Determined Contribution. Submitted to the UNFCCC NDC Registry, 18 September 2025.

BHP Mitsubishi Alliance (2026). Hay Point Coal Terminal.

Bloomberg (2023). China removes all remaining curbs on Australian coal imports. Republished by American Journal of Transportation, 14 March 2023.

BloombergNEF (2025). Malaysia: A Techno-Economic Analysis of Power Generation.

BlueScope (2023). BlueScope delivers underlying EBIT of $1.61Bn in FY2023; approves blast furnace reline and upgrade at Port Kembla Steelworks. ASX announcement, 21 August 2023.

BPS (2025). Foreign Trade Statistics: Imports 2024, Book I, Appendix 4. Badan Pusat Statistik (Statistics Indonesia).

Burdon, R., Talberg, A., Spiller, K., Meinshausen, M., & Lewis, J. (2025). Australia's coal outlook in a warming world: insights from integrated assessment models. Climate Resource, December 2025.

CEPII (2026). BACI: International Trade Database at the Product-Level, release 202601, HS 270112, 2022–2024.

Chalmers, J. and King, M. (2023). Changes to the Petroleum Resource Rent Tax. Joint media release, The Treasury, Canberra, 7 May 2023.

Climate Analytics (2026). A fossil-free Australia: technical appendix. Climate Analytics, September 2026.

Climate Resource (2026). The path to 1.5°C. Climate Resource.

Coal Controller of India (2015). Provisional Coal Statistics 2014–15.

Coal Controller of India (2025). Coal Directory of India 2024–25.

Coal Services (2025). Annual Report 2024–25. Coal Services Pty Ltd.

Connolly, E. and Orsmond, D. (2011). The Mining Industry: From Bust to Boom. Reserve Bank of Australia Conference Volume 2011.

COP31 Presidency (2026). COP31 35-by-35 Global Electrification Pledge. COP31 Türkiye, 21 September 2026.

CSIRO (2025). Modelling sectoral technology and emissions pathways to 2035 and net zero: data and charts, v4. CSIRO Data Access Portal, September 2025.

Dalrymple Bay Infrastructure (2026). Dalrymple Bay Terminal.

DCCEEW (2025a). Australia’s emissions projections 2025. Department of Climate Change, Energy, the Environment and Water, Canberra, November 2025.

DCCEEW (2025b). Electricity and Energy Sector Plan. Department of Climate Change, Energy, the Environment and Water, Canberra, September 2025.

DCCEEW (2025c). Net Zero Plan. Department of Climate Change, Energy, the Environment and Water, Canberra, September 2025.

DCCEEW (2026a). 2026–27 Safeguard Mechanism review: consultation paper. Department of Climate Change, Energy, the Environment and Water, Canberra, August 2026.

DCCEEW (2026b). Australian Energy Statistics 2026. Department of Climate Change, Energy, the Environment and Water, Canberra, September 2026.

DCCEEW (2026c). Australian Energy Update 2026. Department of Climate Change, Energy, the Environment and Water, Canberra, September 2026.

DCCEEW (2026d). Australian Petroleum Statistics, August 2026. Department of Climate Change, Energy, the Environment and Water, Canberra.

Department for Energy and Mining (2026). Final bidders shortlisted in sale of Whyalla Steelworks. Government of South Australia, 27 May 2026.

Díez, M. A., Alvarez, R., & Barriocanal, C. (2002). Coal for metallurgical coke production: predictions of coke quality and future requirements for cokemaking. International Journal of Coal Geology, 50(1–4), 389–412.

DISR (2024). Future Gas Strategy. Department of Industry, Science and Resources, Canberra, May 2024.

DISR (2026a). Domestic Gas Reservation Scheme: exposure drafts. Department of Industry, Science and Resources, Canberra, 10 September 2026.

DISR (2026b). Resources and Energy Quarterly: June 2026. Office of the Chief Economist, Department of Industry, Science and Resources, Canberra, July 2026.

DISR (2026c). Resources and Energy Quarterly: September 2026. Office of the Chief Economist, Department of Industry, Science and Resources, Canberra.

Dynamic Analysis (2024). Turning down the gas: minimising consumer risk. Report for Energy Consumers Australia, September 2024.

Energy Institute (2026). Statistical Review of World Energy 2026, 75th edition. Energy Institute, London, June 2026.

Energy Intelligence (2026a). Iran crisis jeopardizes LNG growth expectations. Energy Intelligence, 12 March 2026.

Energy Intelligence (2026b). Viewpoint: Gas demand cuts grow as Hormuz risks linger. 14 July 2026.

Energy Transformation Taskforce (2020). Whole of System Plan. Energy Policy WA, Government of Western Australia, Perth, October 2020.

Eni (2025). Eni signs a long-term LNG sale agreement with BOTAŞ. Press release, 3 December 2025.

Eurostat (2026). Imports of solid fossil fuels by partner country (nrg_ti_sff).

Evoenergy (2025). Attachment 2: demand forecast, ACT and Queanbeyan-Palerang gas network access arrangement 2026–31. Evoenergy, June 2025.

Focus Taiwan (2026). KMT demands Lai apologize as nuclear power restart nears approval. Central News Agency, 3 September 2026.

Gaulier, G. and Zignago, S. (2010). BACI: International Trade Database at the Product-Level. The 1994–2007 Version. CEPII Working Paper 2010-23.

Geoscience Australia (2026). Australia's Energy Commodity Resources 2026: Gas. Geoscience Australia, Canberra.

GIIGNL (2026). GIIGNL Annual Report 2026: The LNG Industry. Paris, May 2026.

Global Energy Monitor (2024). Global Coal Terminals Tracker. December 2024 release.

Global Energy Monitor (2026). Global Coal Plant Tracker. July 2026 release.

Gorringe, A. (2026). Fuel efficiency alone won’t dig coalminers out of a deepening diesel hole. IEEFA, 5 May 2026.

Government of Colombia (2025). Belém Declaration on the Just Transition Away from Fossil Fuels. Launched at COP30, Belém, 21 November 2025.

Government of Western Australia (2022). State-owned coal power stations to be retired by 2030. Media statement, 14 June 2022.

Government of Western Australia (2026a). WA Domestic Gas Policy. Department of Energy and Economic Diversification, Perth, updated 10 June 2026.

Government of Western Australia (2026b). WA Domestic Gas Policy: Development and application. Department of Energy and Economic Diversification, Perth.

Governments of Colombia and the Netherlands (2026). First International Conference on Transitioning Away from Fossil Fuels. Santa Marta, 24–29 April 2026.

Governments of Vanuatu, Tuvalu, Tonga, Fiji, Niue and Solomon Islands (2023). Outcome of the Second Pacific Ministerial Dialogue on Pathways for the Global Just Transition Away from Fossil Fuels. Port Vila, 15–17 March 2023.

GPA Engineering (2026). Feasibility of Evoenergy gas network beyond 2045. Memorandum 240757-MEMO-002-r0 for Evoenergy, Appendix 3.1 to Evoenergy's revised 2026–31 access arrangement proposal, 8 January 2026.

Graham, P. et al. (2025). GenCost 2024–25: Final Report. CSIRO, in collaboration with the Australian Energy Market Operator.

High Court of Australia (2026). MACH Energy Australia Pty Ltd v Denman Aberdeen Muswellbrook Scone Healthy Environment Group Inc [2026] HCA 35. 7 October 2026.

Houlie, T., Baba, K., Guéret, S., Bowen, J., Quill, E., Welder, L., Cangussu, G., & Hare, B. (2026). A fossil-free Australia: an ambitious Paris-aligned phase-out of coal, gas and oil from the national energy system. Climate Analytics, September 2026.

Hunt, A. (2026). Deal or no deal: Five energy market lessons from the Middle East crisis. IEEFA, 8 July 2026.

IEA (2014–2025). Medium-Term Coal Market Report 2014 and 2015; Coal 2020 to Coal 2025. International Energy Agency, Paris.

IEA (2020). Iron and Steel Technology Roadmap: Towards more sustainable steelmaking. International Energy Agency, Paris, October 2020.

IEA (2024). World Energy Outlook 2024. International Energy Agency, Paris, 16 October 2024.

IEA (2025a). Coal 2025: Analysis and forecast to 2030. International Energy Agency, Paris, December 2025.

IEA (2025b). Energy and AI. International Energy Agency, Paris, April 2025.

IEA (2025c). Gas 2025: Analysis and forecasts to 2030. International Energy Agency, Paris, October 2025.

IEA (2025d). World Energy Outlook 2025. International Energy Agency, Paris, 12 November 2025.

IEA (2026a). Electric Car Markets in a Time of Uncertainty. International Energy Agency, Paris, July 2026.

IEA (2026b). Electrification. Special report, International Energy Agency, Paris, 22 September 2026.

IEA (2026c). Gas Market Report, Q3-2026. International Energy Agency, Paris, July 2026.

IEA (2026d). Quarterly Coal Statistics. International Energy Agency, Paris.

IEA (2026e). Southeast Asia Energy Outlook 2026. International Energy Agency, Paris.

IEEFA (2024). The future of Australian LNG. Institute for Energy Economics and Financial Analysis, June 2024.

International Court of Justice (2025). Obligations of States in respect of Climate Change. Advisory Opinion of 23 July 2025.

JOGMEC (2026). LNG contract register, 2026 edition. Japan Organization for Metals and Energy Security.

KEEI (2026). Monthly Energy Statistics, October 2026. Korea Energy Economics Institute.

Kelly, M. (2026). Industry rejects Hunter coal 'death spiral' analysis. Newcastle Herald, 15 April 2026.

Laidlaw, H. (2020). Liquid fuel security: a quick guide – May 2020 update. Parliamentary Library, Parliament of Australia, Canberra, 8 May 2020.

Lawrence Consulting (2025). Queensland Resources Sector Economic Contribution Study 2024/25. Report for the Queensland Resources Council.

Ministry of Finance, Japan (2026). Trade Statistics of Japan. Customs and Tariff Bureau, Tokyo.

Minx, J. C., Hilaire, J., Müller-Hansen, F., Nemet, G., Diluiso, F., Andrew, R. M., Ayas, C., Bauer, N., Bi, S. L., Clarke, L., Creutzig, F., Cui, R. Y., Jotzo, F., Kalkuhl, M., Lamb, W. F., Löschel, A., Manych, N., Meinshausen, M., Oei, P.-Y., Peters, G. P., Sovacool, B., Steckel, J. C., Thomas, S., Workman, A., & Wiseman, J. (2024). Coal transitions—part 2: phase-out dynamics in global long-term mitigation scenarios. Environmental Research Letters, 19(3), 033002.

Molnar, G. (2022). Economics of gas transportation by pipeline and LNG. In M. Hafner and G. Luciani (eds), The Palgrave Handbook of International Energy Economics. Palgrave Macmillan, Cham, pp. 23–57.

Montoya, D. (2025). Coal mining in NSW: key statistics. NSW Parliamentary Research Service, Research Paper 5/2025, 30 September 2025.

Myllyvirta, L. and Aggarwal, A. (2026). Analysis: India’s power-sector emissions flat for two years due to clean-energy surge. Carbon Brief, 16 September 2026.

Net Zero Australia (2025). Topical Report 1: Updated Net Zero Pathways for Australia. University of Melbourne, University of Queensland and Princeton University, September 2025.

The New Daily (2026). More millions as Whyalla Steelworks jobs slashed. 14 September 2026.

NSW Independent Planning Commission (2022). Mount Pleasant Optimisation Project (SSD-10418): development consent. 6 September 2022; declared invalid by the NSW Court of Appeal, 24 July 2025.

NSW Independent Planning Commission (2026). HVO North and South Open Cut Coal Continuation Projects (SSD-11826681 and SSD-11826621): statement of reasons for decision. 30 September 2026.

NSW Minerals Council (2026). NSW Mining Industry Expenditure Impact Survey 2024/25.

NSW Mining (2026). NSW coal exports surge as demand for our coal booms. NSW Minerals Council, 24 August 2026.

Origin Energy (2026). Origin extends Eraring Power Station operations to 2029. ASX announcement, 20 January 2026.

Parliament of Australia (2022). Climate Change Act 2022 (Cth). Federal Register of Legislation.

Pattaya Mail (2026). Thailand PDP 2026 plan targets more than 60% renewable power. 20 August 2026.

Petroleum Association of Japan (2025). Petroleum Industry in Japan 2025 (English edition). December 2025.

Queensland Government (2016). First shipment from Australia Pacific LNG project. Ministerial media statement, 11 January 2016.

Queensland Government (2025). Queensland Energy Roadmap. Queensland Treasury, Brisbane, 10 October 2025.

Queensland Government (2026). Coal industry review statistical tables: coal sales and exports data. Department of Natural Resources and Mines, Manufacturing and Regional and Rural Development; Queensland Government Open Data Portal, updated 17 September 2026.

Queensland Government Statistician’s Office (2026). Overseas exports by commodity (8-digit AHECC) and country of destination, Queensland and other states and territories, 2015–16 to 2025–26p.

Reeve, A., Wood, T., McKenzie, H., & Jefferson, B. (2026). Out of gas: managing the decline of gas in Australia. Grattan Institute, May 2026.

Reuters (2023). First Australian coal cargoes since end of ban to enter China in Feb. Kitco News, 30 January 2023.

Reuters (2024). Australia’s Fortescue signs $2.8 billion green equipment partnership with Liebherr. Republished by Yahoo Finance, 24 September 2024.

Reuters (2026). First LNG train at QatarEnergy's NFE project is ready to start, two sources say. 7 October 2026.

S&P Global Commodity Insights (2026). INTERVIEW: Japan-Australia energy ties deepen as partnership enters security phase. 30 September 2026.

Saunders, M., Denniss, R., Campbell, R., & Thrower, J. (2026). Diesel use in Australian mining. The Australia Institute, May 2026.

SEFE (2025). SEFE to supply Türkiye's BOTAŞ with LNG for ten years. Press release, 3 December 2025.

Srikanth, R. (2024). Enhancing domestic coking coal availability to reduce the import of coking coal. National Institute of Advanced Studies for NITI Aayog, Bengaluru, November 2024.

SX Coal (2025). Review: Japan Oct coal imports up 6.69% MoM, Australia drives growth. November 2025.

SX Coal (2026). China's 2025 coking coal imports in V-shaped trend; Mongolia & Russia maintain dominance. Sxcoal.com, 21 January 2026 (subscription); republished by APBI-ICMA.

Talberg, A., Self, A., Lewis, J., Spiller, K., Meinshausen, M., Pflüger, M., & Burdon, R. (2026a). Behind the curves: comparing 2100 temperature projections and underlying assumptions. Climate Resource.

Talberg, A., Spiller, K., Burdon, R., Self, A., Pflüger, M., & Jiang, J. (2026b). The last LNG train home: Australia's LNG outlook in a demand-constrained world. Climate Resource, April 2026.

Teubner, J. (2026). Hunter Valley coal contracts point to terminal decline. Institute for Energy Economics and Financial Analysis, 14 April 2026.

Treasury (2025). Australia's Net Zero Transformation: Treasury Modelling and Analysis. The Treasury, Canberra, September 2025.

Türkiye Ministry of Energy and Natural Resources (2026). Natural Gas. Info Bank, August 2026.

UNEP (2025). Emissions Gap Report 2025. United Nations Environment Programme, Nairobi.

UNFCCC (2015). Paris Agreement. Annex to Decision 1/CP.21, FCCC/CP/2015/10/Add.1.

UNFCCC (2023). Decision 1/CMA.5: Outcome of the first global stocktake. FCCC/PA/CMA/2023/16/Add.1, adopted 13 December 2023, Dubai.

UNFCCC (2025). Decision 1/CMA.7: Global Mutirão: uniting humanity in a global mobilization against climate change. FCCC/PA/CMA/2025/19/Add.1, adopted 22 November 2025, Belém.

US EIA (2026a). International Energy Data. U.S. Energy Information Administration.

US EIA (2026b). Nuclear reactor restart in Japan will likely displace natural gas electricity generation. Today in Energy, U.S. Energy Information Administration, 2 March 2026.

Van Vuuren, D. P. et al. (2026). The Scenario Model Intercomparison Project for CMIP7 (ScenarioMIP-CMIP7). Geoscientific Model Development, 19, 2627–2656.

VDKi (2019–2025). Annual Report. Verein der Kohlenimporteure.

Wood Mackenzie (2026a). Analysis of proposed LNG export windfall levy: potential impact on energy project economics and fiscal competitiveness. Published by Australian Energy Producers, April 2026.

Wood Mackenzie (2026b). Four-hour battery storage now beats gas peaking on cost globally. Press release, 8 October 2026.

Woodside (2025). Woodside and BOTAŞ finalise long-term LNG supply agreement. Media release, 29 December 2025.

Xiong, N. (2026). China's 15th Five-Year Plan lifts 2027 LNG imports by 0.5 mt, with little impact on Asian prices. Kpler Insight, August 2026.

Appendices

A1 - Scenarios and demand pathways

The pathways: ScenarioMIP-CMIP7 is the scenario set prepared for the seventh phase of the Coupled Model Intercomparison Project. Its seven scenario families run from ‘High’ to ‘Very Low’; the ‘Very Low’ family is the most ambitious, with emissions falling fastest this decade and net-negative emissions later in the century. Seven integrated assessment models (AIM, COFFEE, GCAM, IMAGE, MESSAGE, REMIND and WITCH) quantified it, several under more than one socioeconomic narrative (SSP1 and SSP2), giving the ten ‘lowest-overshoot’ pathways used here. They peak at 1.63–1.70°C (median 1.68°C) and return to 1.25–1.41°C by 2100.

Eligibility and coverage: A pathway is used for a market only where the model reports the variable needed for that market’s region with a plausible history. A model whose regional use of a fuel in the base year sits far from the observed value is left out for that use. That is why some figures use fewer than ten pathways: nine for Japan’s and South Korea’s gas demand (COFFEE reports no gas for those regions), nine for Figure 3’s coal (COFFEE’s base-year coal sits well above the IEA’s), nine for the three Australian oil figures (COFFEE’s base-year oil sits far below observed use), nine for Australian thermal coal (COFFEE), nine for Australian metallurgical coal (AIM’s industrial coal steps up sharply in 2030) and six for Australian domestic gas, where only the pathways whose region is Australia and New Zealand or Oceania are used: in REMIND’s and MESSAGE’s regions Australia is about a fifth of gas use, and Canada and Japan set the shape. Each figure’s caption gives the count.

Regions and countries: Each model represents the world as a set of regions. For export markets, demand is taken from the region containing each importing country and scaled to that country’s observed consumption. Of the 297 country-to-region mappings 195 use a region broader than the country, so a market such as Vietnam or Türkiye follows its region’s trajectory. For Australia the region is Australia and New Zealand (AIM, COFFEE and GCAM), Oceania (IMAGE), Pacific OECD, which includes Japan (MESSAGE), Canada, Australia and New Zealand (REMIND) or Australia, New Zealand and the Pacific islands (WITCH).

Why the median: The ten pathways are weighted equally and the median is reported, with every pathway shown alongside it. Three models contribute two pathways each (IMAGE, MESSAGE and REMIND), so a model-weighted median would differ slightly. It is kept as a sensitivity in the analysis repository.

Limitations: Integrated assessment models solve for least-cost pathways with perfect foresight, in five-year steps, and smooth over the lumpy decisions that set real timelines, such as a single power station’s closure or a blast furnace reline. Their regional results are indexed to each model’s own base year rather than to observed Australian data, which is why every domestic series is scaled to Australia’s 2024–25 use. Where data gaps exist (international bunker fuels, transport by mode, coal by grade) the chapters and the appendices below say how they are handled.

Deriving the Australian pathways

The ten pathways come from seven IAMs (AIM, COFFEE, GCAM, IMAGE, MESSAGE, REMIND and WITCH), several run under more than one socioeconomic narrative. Each model represents the world as a set of regions. The export analysis takes demand from the regions containing each of Australia's customer markets. The domestic analysis takes it from the region in each model that contains Australia, which in most models also includes New Zealand and in some also includes other countries.

To derive an Australian pathway, each model's regional trajectory for a fuel is indexed to its own starting point and scaled to Australia's observed use in 2024–25, the latest year in DCCEEW's Australian Energy Statistics. Exports are indexed to calendar year 2024. The result shows how fast Australian use would change if it followed its region's path in a 1.5°C world. It does not capture Australian specifics such as the closure schedule of individual power stations or the shape of the gas network. Each fuel chapter therefore compares the result with Australian modelling, such as from AEMO, Western Australia's WOSP, CSIRO, NZA and DCCEEW's projections. Domestic gas is scaled to use excluding the gas the LNG plants burn (1,015 PJ in 2024–25, after removing 438 PJ of plant fuel, 9.9% of the energy exported). The pathways are put on the same boundary by closing each model's regional gas balance against the UN energy balances for 2020: where a model's primary gas carries energy-industry own use as an unexplained residual (COFFEE, IMAGE, WITCH) the residual is removed; AIM's has none; GCAM books the plant fuel inside industrial gas, where it cannot be separated, and is used as reported. REMIND and MESSAGE are left out of the domestic gas figures because Australia is about a fifth of their regions' gas use, so six pathways from five models remain.

The pathways also distinguish how each fuel is used. Coal, gas and oil are each split into unabated fossil use, fossil use with CCS, and non-fossil substitutes, such as solid biomass for coal, biogas and hydrogen for gas, and biofuels and synthetic fuels for oil. Fossil use with CCS counts towards fossil fuel use, because the fuel is still extracted and burned and capture is never complete.

The spread between pathways is wide, and for some fuels it widens over time. A few pathways see Australian gas use rise again late in the century on the back of large-scale CCS. This is why the analysis keeps all ten pathways wherever the regions allow and reports the median rather than relying on any single model. The individual pathways are shown alongside the median throughout.

A2 - LNG methodology

Scope: The analysis covers the 33 countries that together imported 98% of the world's LNG in 2025: countries are ranked by GIIGNL's 2025 import data and the shortest list reaching 98% of the 427.9 Mt traded is taken. Gas demand for each is drawn from the lowest-overshoot pathways (Appendix A1) and scaled to its observed 2025 consumption from the Energy Institute's Statistical Review.

Merit order: Each importer's demand is met first from its own production, then from net pipeline imports, with LNG as the residual. Production and pipeline supply follow a conditional base case built from recent trends and published contracts. Where that base case assumes volumes that are not yet contracted, as for Türkiye, the chapter says so.

Contracts: Contracted LNG supply is drawn from Climate Resource's LNG contract database, developed using GIIGNL annual reports, public company announcements and regulatory filings, and JOGMEC's LNG contract register. The database includes contracts recorded to the end of 2025, updated with reviewed public disclosures through October 2026 (Appendix A3). Each contract's annual quantity is counted over its term. Portfolio on-sales are excluded so that volumes are not counted twice, and contracts with no derivable end year are left out. For Australia the contracts cover 77% of observed 2024 exports. Contract flexibility is approximated from delivery terms, with free-on-board contracts treated as divertible and delivered ex-ship contracts as tied to their buyer, not from the terms of any specific agreement.

Capacity: Available liquefaction capacity follows the IEA World Energy Outlook 2025 anchors of 565 bcm a year in 2024 and 830 bcm in 2030 (existing and under-construction plants), interpolated between them and held at 830 bcm thereafter, with no retirements and no projects yet to take a final investment decision. Volumes are converted at 1.36 bcm per million tonnes of LNG.

Updates from previous analysis: The analysis in this report updates the previous analysis with changes to three key inputs:[149]

- The demand profile is now derived from the latest generation of highest-ambition pathways, peaking at around 1.7°C.
- Country coverage is extended from the 19 largest LNG-importing economies, covering around 90% of global LNG trade, to 33 countries, covering around 98%. The previous analysis scaled its 19-country result up by a flat factor to approximate the remaining 10% of global demand. That approximation is no longer needed.
- The contract database has been updated from the earlier GIIGNL-based compilation. As described above, the current forward series combines reviewed public disclosures through October 2026 (Appendix A3) with the 2026 JOGMEC register of agreements concluded to the end of 2025.[150]

A3 - Publicly disclosed changes to LNG supply contracts, January to October 2026

Figure A3-1 shows each of the publicly disclosed changes to LNG supply contracts between January and October 2026 that added supply and have a disclosed term, drawn over its contract term with thickness by volume; Table A3-1 lists every change, including the five terminations.

[149] Talberg et al. (2026b).

[150] GIIGNL (2026); public company announcements and regulatory filings reviewed through October 2026 (Appendix A3); JOGMEC (2026).

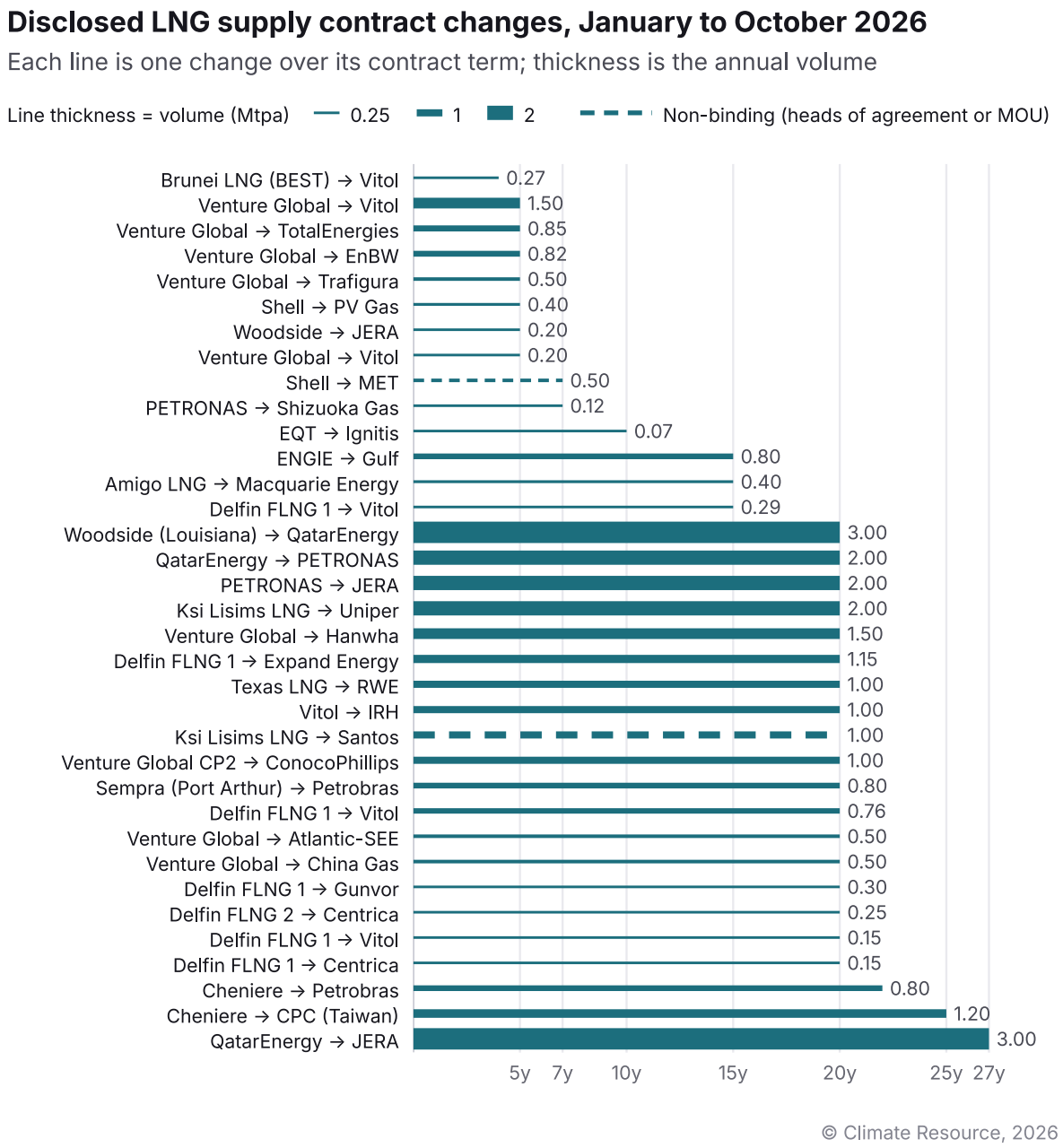


Figure A3-1: Publicly disclosed LNG supply contract changes, January to October 2026, by term and volume (Mtpa); non-binding agreements dashed; all 42 are listed in Table A3-1. Source: company and buyer releases; US Department of Energy LNG export docket filings; Climate Resource analysis.

Of 42 disclosed contract changes in that period, 41 with a stated volume, 39.2 Mtpa changed hands: 35.0 Mtpa of new, increased, extended or finalised supply and 4.2 Mtpa of terminations. Twenty-one of the 41 relate to just four still-ramping North American developments, Commonwealth LNG, Delfin FLNG, Venture Global's portfolio and Texas LNG, which together account for 14.2 Mtpa. About 80% of the added volume is being sold on a portfolio basis, from a seller's portfolio or to a trader or portfolio player,which points to more flexible, multi-source supply rather than one project tied to one buyer. This appears to be driven more by sellers than by traders: independent trading houses and other portfolio buyers (Vitol, Macquarie, Gunvor, Trafigura, TotalEnergies, MET, Hartree, IRH, Expand, Santos, PETRONAS, ConocoPhillips and QatarEnergy) are the counterparty in 21 of the 41

changes, covering 20.7 Mtpa, against 18.6 Mtpa in the remaining changes, most of them between producers and end-use buyers. The pattern suggests producers are adopting flexible, portfolio-style selling to position for a contested market. These are disclosed events rather than a complete record of 2026 contracting, and some deals appear twice as they move from a memorandum to a binding agreement.

Only three of the 42 changes involve Australian companies. Santos signed a non-binding heads of agreement with Ksi Lisims LNG to buy 1.0 Mtpa of Canadian gas, and Woodside is the seller in a new binding sale and purchase agreement with JERA for 0.2 Mtpa of portfolio supply. Whether this adds to Australia's own export book depends on where that gas actually originates, which is not confirmed in the disclosed terms. Woodside's Louisiana LNG project is also the seller in a binding agreement to supply QatarEnergy with up to 3.0 Mtpa of United States LNG for 20 years, which adds nothing to Australia's own export book. The first two deals are small relative to the period's 39.2 Mtpa total, and the remaining 39 changes run through Australia's established competitors: US sellers (65% of the volume changed), along with Qatar, Mexico, Canada, Malaysia and Brunei.

Table A3-1: Publicly disclosed changes to LNG supply contracts, January to October 2026.

Seller / project owner	Buyer	Project / route	Volume (Mtpa)	Term	Type
Shell (Shell Eastern Trading)	PetroVietnam Gas	Shell portfolio to Vietnam (DES, Thi Vai)	0.40	5 yrs	New binding SPA
ENGIE	Gulf Development	ENGIE portfolio to Thailand	0.80	15 yrs	New binding SPA
Woodside	JERA	Woodside portfolio to Japan (DES)	0.20	5 yrs	New binding SPA
Texas LNG (Glenfarne)	RWE Supply & Trading	Texas LNG (pre-FID) to RWE portfolio	1.00	20 yrs	New binding SPA
Brunei Energy Services & Trading (BEST)	Vitol	Brunei LNG to Vitol's Asian operations	0.27	4 yrs	Extension
QatarEnergy	JERA	Qatar LNG production to Japan (DES)	3.00	27 yrs	New binding SPA
QatarEnergy	PETRONAS LNG	Qatar to Peninsular Malaysia	2.00	20 yrs	New binding SPA
Shell	MET International	Shell US portfolio to European regasification terminals	0.50	7 yrs	Memorandum of Understanding (non-binding)
Venture Global	Hanwha Aerospace	Venture Global portfolio to Korea	1.50	20 yrs	New binding SPA
Cheniere Marketing International	CPC Corporation, Taiwan	Cheniere portfolio to Taiwan (delivered)	1.20	25 yrs	New binding SPA
Venture Global	Trafigura	Venture Global portfolio, US LNG	0.50	5 yrs	New binding SPA
Commonwealth LNG	JERA	Commonwealth LNG (pre-FID, Louisiana) to JERA (FOB)	−1.00	20 yrs	Termination
Corpus Christi Liquefaction (Cheniere)	Orlen (formerly PGNiG)	Corpus Christi Stage 3 to Poland	−1.45	17 yrs	Termination

Seller / project owner	Buyer	Project / route	Volume (Mtpa)	Term	Type
Venture Global	Vitol	Venture Global portfolio	1.50	5 yrs	New binding SPA
Delfin LNG	Chesapeake Energy (Expand Energy)	Delfin FLNG 1 (Louisiana) to Chesapeake, on-sold to Gunvor	−0.60	20 yrs	Termination
Delfin FLNG 1	Expand LNG (Expand Energy)	Delfin FLNG 1 (Louisiana) to Expand	1.15	20 yrs	New binding SPA
Delfin FLNG 1	Gunvor International	Delfin FLNG 1 (Louisiana) to Gunvor (FOB)	0.30	20 yrs	New binding SPA
Delfin LNG	Hartree Partners	Delfin FLNG 1 (Louisiana) to Hartree (FOB)	−0.60	20 yrs	Termination
Amigo LNG (Epcilon LNG)	Macquarie Energy	Amigo LNG (Sonora, Mexico, US gas) to Macquarie (FOB)	0.40	15 yrs	Volume increase
Venture Global	TotalEnergies	Venture Global portfolio	0.85	5 yrs	New binding SPA
Venture Global	Vitol	Venture Global portfolio	0.20	5 yrs	Volume increase
Delfin FLNG 1	Vitol	Delfin FLNG 1 (Louisiana) to Vitol (FOB), SPA 1	0.15	20 yrs	Volume increase
Delfin FLNG 1	Vitol	Delfin FLNG 1 (Louisiana) to Vitol (FOB), SPA 2	0.76	20 yrs	New binding SPA
Delfin FLNG 1	Vitol	Delfin FLNG 1 (Louisiana) to Vitol (FOB), SPA 3	0.29	15 yrs	New binding SPA
Delfin FLNG 1	Centrica	Delfin FLNG 1 (Louisiana) to Centrica (FOB), SPA 1	0.15	20 yrs	Volume increase
Delfin FLNG 2	Centrica	Delfin FLNG 2 (Louisiana) to Centrica (FOB), SPA 2	0.25	20 yrs	New binding SPA
Delfin LNG	Gunvor Singapore	Delfin FLNG 1 (Louisiana) to Gunvor (FOB), SPA 1 of 2023	−0.60	20 yrs	Termination
PETRONAS LNG	JERA	PETRONAS portfolio, primarily Malaysia, to Japan	2.00	20 yrs	New binding SPA
Venture Global	Atlantic-SEE LNG Trade	Venture Global portfolio to Greece	0.50	20 yrs	Volume increase
Venture Global	EnBW	Venture Global portfolio to Germany	0.82	5 yrs	New binding SPA
Vitol	IRH Global Trading	Vitol portfolio to IRH (FOB)	1.00	20 yrs	SPA finalised
PETRONAS LNG	Shizuoka Gas	PETRONAS portfolio to Japan (DES)	0.12	7 yrs	New binding SPA
Ksi Lisims LNG	Uniper	Ksi Lisims LNG (British Columbia, pre-FID) to Uniper (FOB)	2.00	20 yrs	New binding SPA

Seller / project owner	Buyer	Project / route	Volume (Mtpa)	Term	Type
EQT	Ignitis	EQT US portfolio to Lithuania (Klaipeda)	0.07	10 yrs	New binding SPA
Ksi Lisims LNG	Santos	Ksi Lisims LNG (British Columbia, pre-FID) to Santos portfolio	1.00	20 yrs	Heads of Agreement (non-binding)
Sempra Infrastructure	Petrobras	Port Arthur LNG Phase 2 (Texas, under construction) to Brazil	0.80	20 yrs	New binding SPA
Venture Global	China Gas Holdings	Venture Global Louisiana projects to China	0.50	20 yrs	New binding SPA
Shell	MET International	Shell US portfolio to Europe	n/d	Multi-year	New binding SPA
Cheniere Marketing	Petrobras	Cheniere portfolio to Brazil (FOB)	0.80	22 yrs	New binding SPA
Venture Global CP2 LNG	ConocoPhillips	CP2 LNG Phase 2 (Louisiana) to ConocoPhillips portfolio (FOB)	1.00	20 yrs	New binding SPA
Cheniere (Sabine Pass and Corpus Christi)	QatarEnergy	US Sabine Pass and Corpus Christi to QatarEnergy portfolio (FOB)	4.00	Early 2030s to 2054	New binding SPA
Woodside Louisiana LNG	QatarEnergy	Louisiana LNG (United States) to QatarEnergy portfolio (FOB)	3.00	20 yrs	New binding SPA

A4 - Coal methodology

Demand: Each market's coal demand follows its region's lowest-overshoot pathway (Appendix A1), scaled to the market's observed consumption. Metallurgical coal follows the models' industrial coal use (Final Energy|Industry|Solids|Coal), which also includes other industrial coal use. This is the closest measure in the published ScenarioMIP-CMIP7 dataset,[151] which does not report coal use in iron and steel separately. Testing against other IAM scenario data that report coal use in steel separately shows little effect on the results for Australia's metallurgical coal exports. For comparison, the IEA's Net Zero Emissions by 2050 Scenario has global coking coal production 22% below 2023 in 2030, 45% in 2035 and 91% in 2050.[152] Thermal coal is the remainder of the region's primary coal use. Observed consumption, production and trade come from the IEA, the US EIA, Eurostat, national statistics and DISR.

Merit order and shares: Each market's import requirement is its demand less its own production, held to zero where production exceeds demand, and each supplier keeps its documented share of those imports. Australia's share is its pooled 2022 to 2024 share in DISR's export data, except for China and India (below) and for India's metallurgical coal,

[151] Van Vuuren et al. (2026).

[152] IEA (2024), Table 3.3.

where Australia's share falls from its 2024 level at half the rate of its FY2015 to FY2025 decline and reaches zero in 2049. Where a market's statistics do not separate grades (Vietnam, Germany, Indonesia and Brazil), coking-only proxies are used and the market is marked provisional.

China and India: Both mine nearly all the coal they burn, so as their demand falls under the pathways they can soon meet all of it from domestic production. This occurs from 2026 for China's thermal coal in most pathways, 2031 or 2032 for India's, and between 2028 and 2035 for China's metallurgical coal. Their coal is mined far inland, and the coastal power stations and steelworks that take imports will not switch to domestic supply overnight, so Australia's exports are held at their 2025 levels until that point and then wound down to zero over five years rather than stopped at once. A ten-year wind-down would move the exit years by at most a year.

Other markets: exports to markets outside the five DISR destinations are assumed to fall at the same rate as exports to the five combined, so the five keep their calendar-2025 share of national exports at 84% for thermal coal and 75% for metallurgical coal.

A5 - Coal export system mapping

Notes to Figures 14, 15 and 16

Mines: Each circle is an operating mine or reporting unit. Queensland mines use financial year 2025-26 output or exports and the product mix in the Queensland Government's mine returns. New South Wales mines use 2024 saleable production (NSW Parliamentary Research Service); no mine-level product split is published there, so a mine that sells both grades is drawn in a third colour. Output includes coal sold in Australia. Domestic-only mines are ringed: Loy Yang and Yallourn are tracker estimates scaled to the 38.1 Mt of brown coal used in 2024–25, Premier and Ewington share Western Australia's 5.3 Mt of 2024–25 coal sales, and the Tasmanian mines are at 2023 output.

Rail and road hauls: Black lines are coal haul routes, the shortest path along the national rail layer from each mine to its system's port. They show which railways a system depends on, not contracted haulage. The Carmichael Rail Network is added from the Queensland Government's railway layer. Four mines send their coal out by road, drawn dashed: Yarrabee and Jellinbah truck about 37 km and 25 km to the Boonal loadout on the Blackwater line, Baralaba North about 60 km to its loadout near Moura on the Moura line, and Appin's washed coal goes by public road to Port Kembla.

Systems: Queensland systems are the port corridors of the government returns, not exclusive catchments. New South Wales mines are assigned to Newcastle or Port Kembla by location. Three mine-mouth power station mines in southern Queensland with no rail link are left out.

Basins: Coal basins are drawn to their full extent, including where they lie under younger cover, with the Surat and Clarence-Moreton basins over the older basins they cover. Of the 78 mines, 76 lie in one of the six basins, and Callide and Clermont work small outlying basins that are not drawn.

Port exports: The export bars are for 2024-25. Queensland ports are the Queensland Government's exports by port corridor, with Brisbane taken as the exports of the two mines that rail to it (New Acland and Cameby Downs, 5.0 Mt) and Gladstone as the rest of

southern Queensland. Port Kembla (7.1 Mt) is the New South Wales total of 153.0 Mt less the Port of Newcastle's own coal loadings for the year (145.9 Mt). The state's grade split is the ABS customs tonnes by state of origin, 10.5% metallurgical in 2024–25. No split is published for either port: Port Kembla's is taken as that of its mines' output (62% metallurgical) and Newcastle's as the rest of the state's (8%).

Sources: Geoscience Australia, Australian Geological Provinces (coal basins); Global Energy Monitor, Global Coal Mine Tracker and Global Coal Terminals Tracker; Queensland Government coal statistics, coal sales and exports by mine and quarterly coal reports (compiled by Mining Capital Funds); Coal Services annual reports; NSW Government, NSW Coal Industry 2026-50; Port of Newcastle monthly trade reports (Transport for NSW open data); National Freight Data Hub rail map; Queensland Government, Railways - Queensland; Yancoal, Jellinbah Group, Baralaba Coal Company and GM3 (road hauls); ABS state boundaries; NSW Parliamentary Research Service, Coal mining in NSW: key statistics, data file (2024 saleable output by New South Wales mine); Queensland Government Statistician's Office, ABS customs exports by state of origin (New South Wales grade split); WA Department of Mines, Petroleum and Exploration, major commodities data file (WA coal sales); WA Government media statement, 21 January 2026 (Ewington); Australian Energy Statistics 2026 (brown coal total); Climate Resource analysis.

A6 - Oil methodology

Australian oil use follows the same approach as coal and gas (Appendix A1). The variable is each model's Primary Energy|Oil for the region containing Australia, indexed to the model's own 2025 value and scaled to Australia's 2024–25 primary oil use of 2,352 PJ,[153] which includes the fuel sold in Australia to international aircraft and ships. The COFFEE model is excluded from the oil median here because its base-year oil use sits far below the observed level, leaving nine pathways. Annual values are interpolated between the models' five-year steps, and the exit years run from the first year the interpolated median stays below 20% of 2024–25 use (2050) to the first year it stays below 5% (2067). It stays below 10% from 2058.

The CSIRO/CCA scenarios report final petroleum use and we convert them to primary energy using the FY2021 ratio of primary to final oil use in Australian Energy Statistics. Net Zero Australia is shown as published, and its treatment of international bunkers may differ.

Oil use by sector (Figure 26) uses final rather than primary energy and excludes international aviation and shipping. No pathway reports transport energy by mode, so domestic aviation's share of transport oil is inferred from each pathway's aviation emissions, and oil in sectors without a reported fossil split is allocated in proportion to their liquids use. Two pathways report no aviation emissions, so their transport is not split. Sector shares are therefore indicative.

[153] DCCEEW (2026b), Table C.

A7 - Comparison with other assessments

Each comparator assessment answers a different question:

- The Future Gas Strategy (2024) models Australian LNG export volumes under the IEA's three World Energy Outlook scenarios, using a global gas market model in which suppliers compete on cost: 81 Mt in 2022–23 falling to 66, 20 and 7 Mt by 2050 under the Stated Policies, Announced Pledges and Net Zero scenarios.
- Treasury's Net Zero Transformation modelling (2025) is an economy-wide model that takes export demand as an input, from IEA demand paths for coal and the Future Gas Strategy for LNG, consistent with 'well below 2°C' (median warming of about 1.7°C in 2100): coal output falls 47% by 2035 and 72% by 2050 from 2025, gas and LNG output 27% and 67%, and emissions from domestic gas use 70% by 2050.
- Climate Analytics' A fossil-free Australia (2026) uses one model, REMIND, under its Highest Possible Ambition pathway (peaking around 1.7°C and falling to about 1.2°C by 2100) and holds Australia's share of each trading partner's fossil fuel consumption constant, giving coal exports down 95% by 2040 and LNG of 63 Mt in 2035, 30 Mt in 2040 and 7 Mt in 2050.

The temperature outcomes are comparable: the lowest-overshoot pathways, the IEA's Net Zero scenario and the Highest Possible Ambition pathway all peak at about 1.6–1.7°C and return towards or below 1.5°C, and Treasury's ~1.7°C in 2100 is less ambitious.

This report differs in three ways:

1. It uses ten pathways from seven models rather than one.
2. It works from each importer's own balance, so that domestic production and pipeline supply are used before imports and only the residual is open to Australia.
3. For LNG it starts from the contracts already signed rather than from a demand path.

The first makes the results less dependent on any one model's view of coal. The second and third, with more ambitious pathways than Treasury's, are what make the export dates earlier than the Future Gas Strategy's and Treasury's.

A8 - Data centres and electricity demand

Figure A8-1 shows the IEA's four possible global pathways for data centre electricity demand.

Even in its most demand-intensive 'Lift-off' case, the share of electricity for data centres does not reshape the 2035 picture. Across the four sensitivity cases that the IEA models (Headwinds, Base, High Efficiency and Lift-off) data centres account for between about 4% and 10% of the growth in global electricity generation to 2035 in the IEA's Stated Policies Scenario (STEPS) (about 7% in the Base case). The remaining roughly 90% of growth is driven by more conventional sources: electrification of transport and industry, cooling demand, and general economic growth in emerging economies. Data centres matter for specific grids and specific contracts, but they are not, at a global level, the dominant factor in electricity demand this decade.

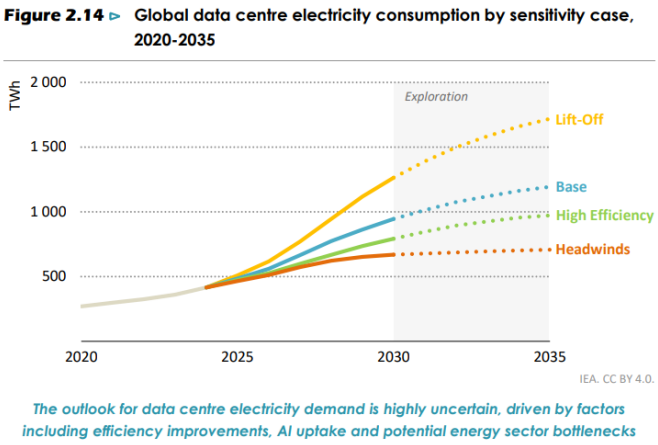


Figure A8-1: Global data centre electricity consumption by sensitivity case, 2020 to 2035 (TWh). Source: IEA (2025b), Energy and AI, Figure 2.14, CC BY 4.0.

Figure A8-2 shows the IEA's STEPS pathway, expanded into a band using the Headwinds-to-Lift-off sensitivity range, with High Efficiency shown as the central dotted case, plotted against the IAM runs used to derive this report's demand pathway. Across the ten pathways, 2035 generation ranges from 34.0 to 54.3 thousand TWh, with a median of 45.6 thousand TWh; transferring the IEA data-centre cases onto the Stated Policies outlook moves 2035 generation only between 44.0 and 44.8 thousand TWh.

The STEPS band sits at the median of the lowest-overshoot pathways in 2030 and just below it in 2035, and its width (0.8 thousand TWh) is a small fraction of the spread across the pathways (20 thousand TWh). In other words, the uncertainty range the IEA attributes to data centres is already spanned by the ordinary variation across the climate-scenario model runs. Data centres and artificial intelligence (AI) compute demand are not critical factors in the analysis of LNG demand projections in a 1.5°C world.

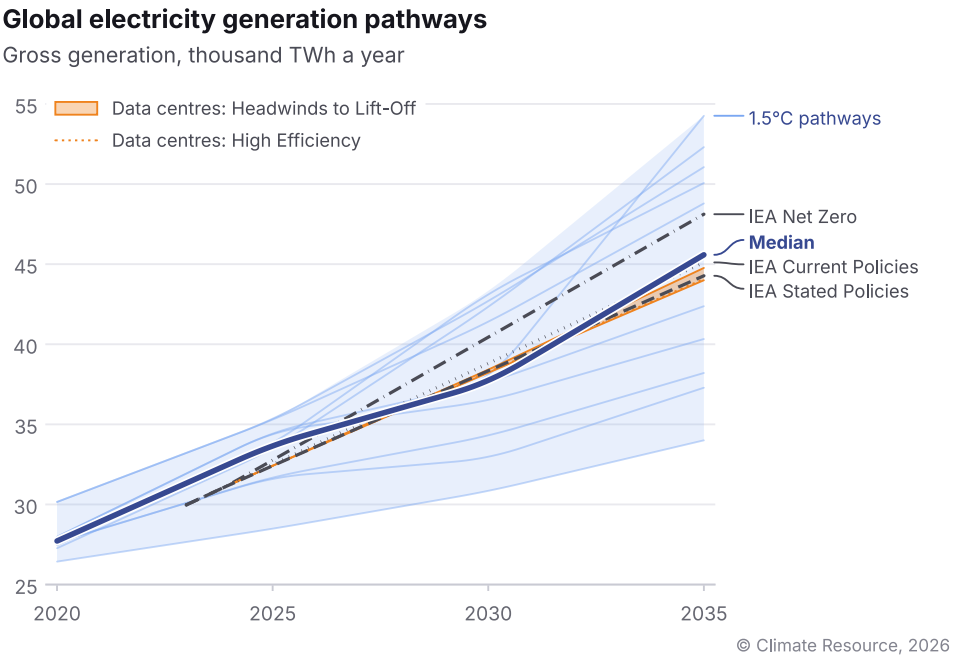


Figure A8-2: Global gross electricity generation, 2020 to 2035 (thousand TWh per year): the lowest-overshoot pathways against the IEA WEO 2025 scenarios, with the IEA data-centre cases as a band on the Stated Policies Scenario. Source: ScenarioMIP-CMIP7 lowest-overshoot pathways; IEA; Climate Resource analysis.