CLIMATE ANALYTICS

Emissions as usual:

Implications for the Safeguard Mechanism of LNG and coal mine projects

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We regret any errors or omissions that may have been unwittingly made.

Cover photo:
Coal loading machinery for transferring to ships via conveyor belt at the coal export terminal at Kooragang Island, Newcastle, New South Wales. Photo by AlecTrusler2015.

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Executive Summary

As part of its efforts to meet its 2030 emissions reduction target, the Albanese government is reforming the Safeguard Mechanism (SGM), one of its main tools for aligning business operations with the country's climate commitments. Facilities covered by the Safeguard Mechanism accounted for about 27% of Australia's emissions in 2021.

Importantly, these include the production of coal and Liquefied Natural Gas (LNG), accounting for around half of total SGM emissions, and both of which are set to ramp up. In this report, we calculate the abatement gap they will create for Australia.

Achieving reductions in this area is an important part of the Albanese government's policy framework for meeting Australia's emissions reduction target of 43% below 2005 levels by 2030.

In this report, we examine the implications of committed and proposed developments in the LNG and coal mining sectors for reform of the Safeguard Mechanism.

Under its proposed changes to the SGM, the Australian Government proposes setting a reduction target for this sector of around 27% by 2030 from 2020/21 emission levels, with a fixed limit on emissions in 2029/2030 of 100 $MtCO_2e$ per year.

The energy-intensive facilities covered by the mechanism will have a binding emissions baseline that must reduce, on average, by 4.9% a year from 2023/24 to 2029/30. Facilities will be required to meet this baseline by reducing their emissions, purchasing safeguard mechanism credits (SMCs) from companies or facilities that have reduced emissions below their baselines, or buying offsets in the form of Australian carbon credit units (ACCUs).

This report projects the likely emissions from the pipeline of planned projects in the LNG sector and coal mining, including extensions or expansions of existing projects and new greenfield developments. We calculate the abatement gap for Australia and the SGM caused by the projected production of coal and Liquefied Natural Gas (LNG), both of which are set to ramp up this decade.

Key findings

- Our projections show that emissions from existing, committed and proposed new and expanded LNG and coal mine projects will, on their own, would lead to emissions amounting to 83-112 $MtCO_2$ per year in 2030.
- This would exceed the 100 $MtCO_2e$ Safeguard Mechanism baseline emission limit for all facilities in 2029/30. In other words, if all potential LNG and coal projects go ahead, their resulting emissions will exceed the 2030 SGM baseline on their own. This would leave no room for other facilities under the scheme who would find

themselves having to make additional steeper cuts to keep to the Government's SGM limit.

Coal mine emissions

Coal mines covered under the Safeguard Mechanism made up 23% of total SGM-covered emissions, emitting around 31 $MtCO_2e$ in 2020/21. In our projections, we include committed projects, expansions of existing facilities over time, and proposed new mines undergoing feasibility assessments or that have been publicly announced.

Under the SGM, coal mine projects have an estimated emissions baseline limit of 22-29 $MtCO_2e$ by 2029/30.

Key findings

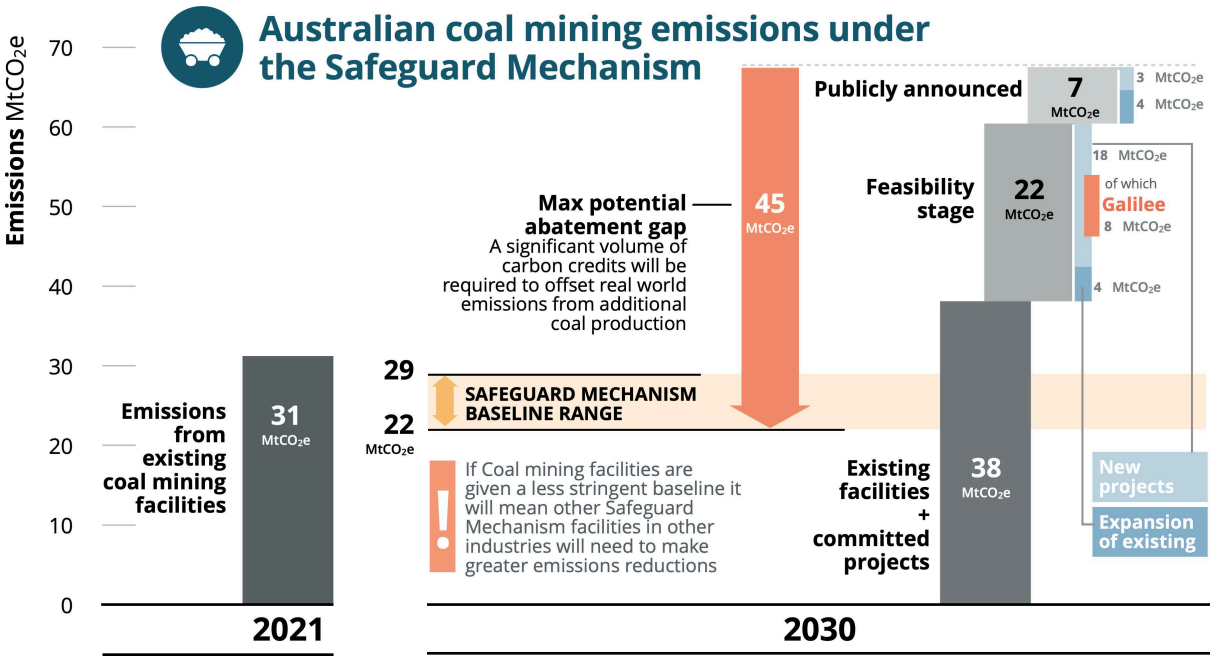
The total potential emissions from both existing and new mines amount to around 67 $MtCO_2e$ in 2029/30 which would consume a substantial share of the total 100 $MtCO_2e$ limit for all SGM facilities (see figure below). This is around 166% above 2021 levels.

We estimate the 2030 abatement gap for coal facilities - projected emissions compared to the required baseline in 2030 - ranges from 38 to 45 $MtCO_2e$ if all projects were to go ahead.

These calculations include:

- Existing and committed coal mine facilities, where we project an increase of at least 23% to 38 $MtCO_2e$ by 2029/30 compared to government projections of a 10% decline in total coal mine emissions over the same period.
- Including publicly announced projects and those at the feasibility stage of development emissions.
- For only committed extensions and expansions of existing coal mines, after accounting for likely closures, the projected 2030 emissions would be 32 $MtCO_2e$, 3% above 2020/21 levels, surpassing the estimated 2030 baseline range for all coal mines on the SGM.
- Committed new coal mine plans add 6 $MtCO_2e$, feasibility stage projects 22 $MtCO_2e$, and publicly announced projects a further 7 $MtCO_2e$.
- The total of coal mine project emissions could reach up to 67 $MtCO_2e$.

This implies that other sectors will have to bear an additional emission reduction burden and steeper emissions reductions if the SGM is to stay within the overall 100 $MtCO_2e$ limit.



Liquefied Natural Gas (LNG) emissions.

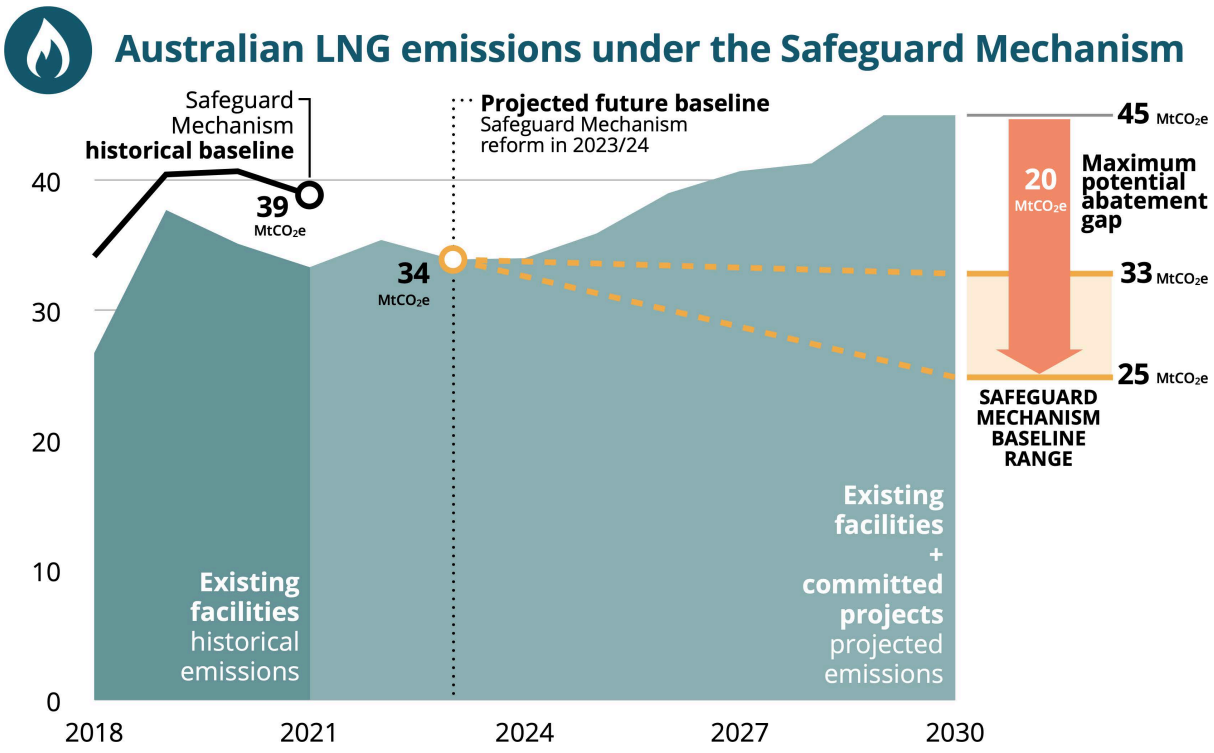
Key findings

We calculate that committed and very likely changes in LNG production, including the Pluto project expansion in Western Australia and new gas fields to supply existing facilities, will increase LNG emissions by 36% above 2021 levels by 2030 to 45 $MtCO_2e$ per year, significantly higher than the government's 2022 projections, which show a 20% rise (see figure below).

If all planned LNG-related projects were to go ahead, the 2030 abatement gap – total emissions compared to the estimated 2030 baseline of 25-33 $MtCO_2e$ – would be between 12 to 20 $MtCO_2e$.

- The majority of LNG-related emissions increases will come from more carbon-intensive gas fields used for extraction.
- The planned new gas field supply changes will increase Australia's emissions by more than 7 $MtCO_2e$ without any increase in LNG production. Woodside's North West Shelf Karratha gas plant is planning to access gas supply from the Browse Basin. The Santos Darwin LNG will turn to accessing gas from the carbon-intensive offshore Barossa gas field.
- The deployment of a second train at Woodside's Pluto plant on the Burrup Peninsula would add about 1.7 $MtCO_2e$/year, almost doubling its current emissions of 1.9 $MtCO_2e$/year. The connection of the Crux gas field to Shell's Prelude Floating LNG and a production increase at the Ichthys plant will account for the rest of the additional emissions.

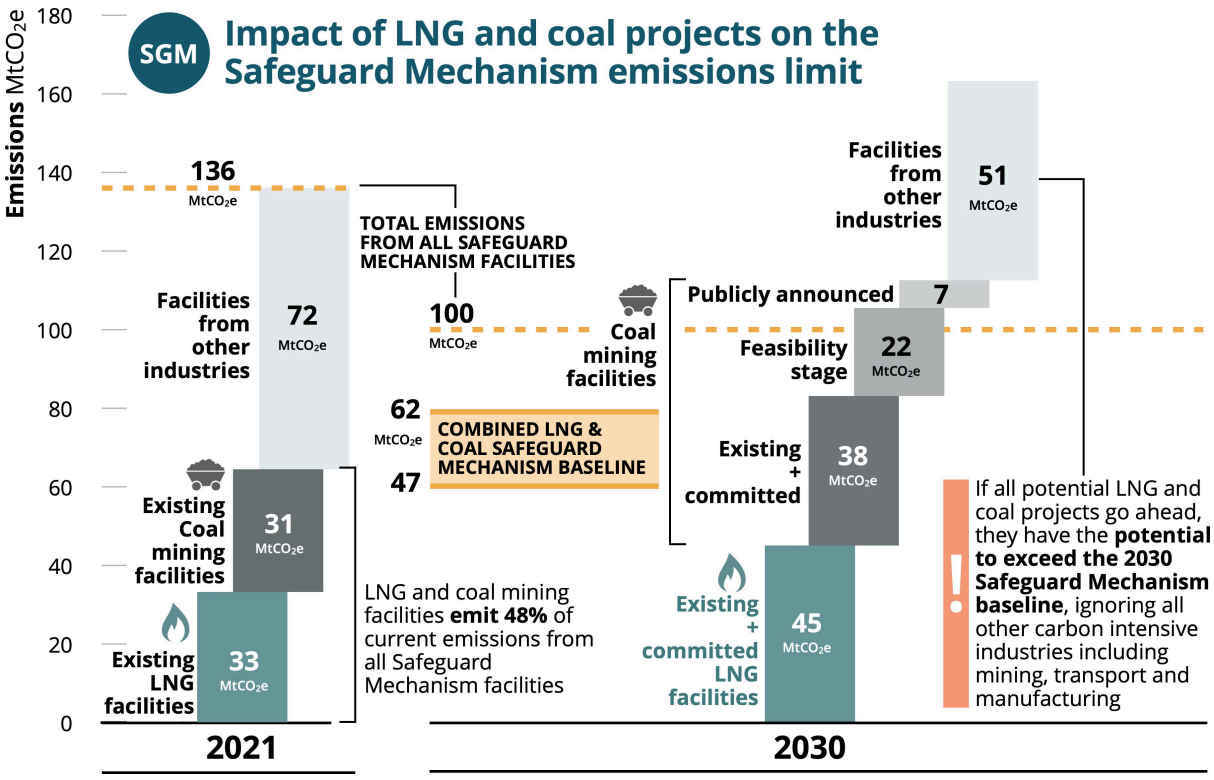
- All the LNG facilities undergoing supply source changes in the coming years will produce LNG with a higher-than-average carbon intensity. It is likely this will raise concerns from Australia's international trading partners who are increasingly looking to supply themselves with less polluting fuels.
- The average production-weighted carbon intensity of Australian LNG is expected to increase by 21% from about 0.43 tCO_2e per tonne of LNG to 0.52 tCO_2e per tonne of LNG between 2021 and 2030.



Very large cumulative abatement gap projected for LNG and Coal

Key findings

- For LNG producers, we find a cumulative abatement gap between likely future emissions to 2030 and their potential emissions baselines, trade-exposed adjusted and industry average, of between 49-75 $MtCO_2e$ respectively (see figure below).
- For coal, the respective numbers are 24-160 $MtCO_2e$ under a trade-exposed adjusted baseline, and 46-184 $MtCO_2e$ under an industry average baseline.
- The total cumulative abatement gap is estimated at 73-259 $MtCO_2e$.
- If all SGM-covered facilities collectively are to stay within the 100 $MtCO_2e$ limit, other sectors will have to bear the burden of additional and steeper cuts.



LNG and coal abatement gap likely to be met by purchasing offsets

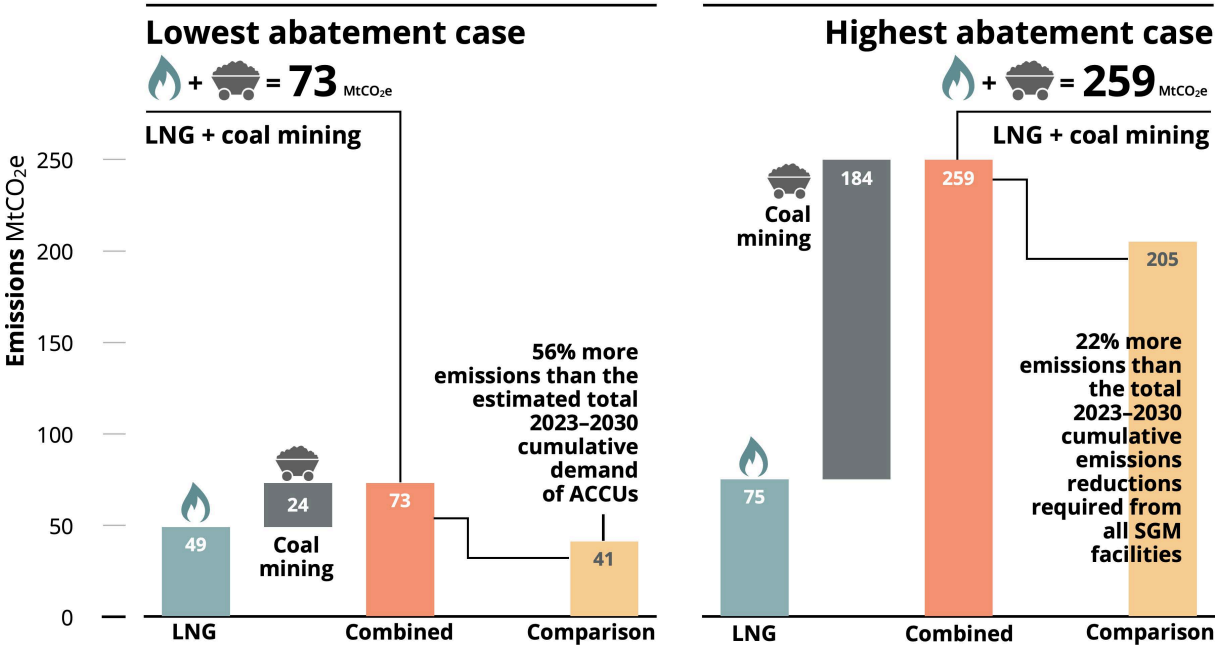
Given the technical difficulties and high costs experienced by carbon capture and storage projects around the world, including Chevron at its Gorgon facility, it is unlikely that a large share of LNG production emissions will be reduced using this method. There appear to be few currently viable solutions to reduce coal mine fugitive emissions.

A large majority of LNG and coal mine emissions are likely to be addressed through the purchase of ACCUs. In a worst-case scenario, where all planned LNG and coal mine expansions and new projects eventuate, the total abatement gap - above an industry average baseline that could be met with ACCUs - totals nearly 260 $MtCO_2e$. This is more than the total number of ACCUs issued by the government to date.

At a minimum, using a trade-exposed adjusted baseline, and with only committed expansions proceeding, this would still total 73 $MtCO_2e$, still almost double the government's projected total ACCU usage across all SGM facilities.

How many Australian Carbon Credit Units will be needed?

Estimated high and low range of total abatement needed for LNG and coal mining facilities from 2023–2030 - likely to be met with ACCUs



Government projections appear to massively underestimate likely offset demand

The Government projects a modest use of ACCUs, totalling 9 $MtCO_2e$ of abatement in 2030, or 20% of the total required abatement in that year. A conservative assumption that 20% of the total projected cumulative abatement task is met with offsets would mean the purchase of 41 million ACCUs, or 41 $MtCO_2e$ of abatement to 2030.

This figure is dwarfed by the total cumulative abatement required for LNG and coal producers to meet their respective emissions reduction requirements. For these sectors, if all abatement were met with ACCUs the offset demand would be at a minimum of 80% higher and could be more than six times higher if all the LNG and coal projects in the pipeline proceed.

Under either scenario, or anywhere in between, this represents an enormous source of demand for ACCUs, incentivising a wholesale increase in offsets generated using suspect methods that independent experts believe often do not represent genuine emissions reductions.

A recent analysis by Climate Analytics outlines the many acute problems with land sector offsets, including those relating to the Australian context. We find that land sector offsets are fundamentally less effective compared to a direct emissions reduction at source, due to the impermanence of the land sector's ability to store carbon, while several land sector methodologies have been shown to fail to ensure additionality of emissions reductions, or to achieve any emissions reduction at all.

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Introduction

In 2022, Australia submitted an updated Nationally Determined Contribution (NDC), committing to reduce greenhouse gas (GHG) emissions by 43% below 2005 levels by 2030. As part of its efforts to meet this target, the government is currently reviewing the Safeguard Mechanism (SGM), one of its main tools for aligning business operations with the country's climate commitments.

The scheme applies to facilities that emit more than 100,000 tonnes of carbon dioxide equivalent (tCO_2e) per year. In 2020/21, facilities covered by the SGM emitted 136 $MtCO_2e$, 28% of Australia's total emissions and an increase from 2016/17 levels of 131 $MtCO_2e$. The government projects SGM emissions to reach 143 $MtCO_2e$ in 2022/23. Without reform, emissions from the SGM would reach 146 $MtCO_2e$ at the end of the decade (Department of Climate Change 2023).

Under the reformed SGM, facilities will be allocated an emissions baseline that declines each year from 2023/24 to 2029/30. Under the previous government, the emissions baselines were essentially allowing increases in emissions. For example, in 2020/21, the total SGM baseline for coal was 46 $MtCO_2e$ emissions.

Facilities will be required to reduce their emissions to either meet the emission limits linked to their baseline, purchase emission Safeguard Mechanism Credits (SMCs) from facilities that have reduced below their baseline, or purchase offsets in the form of ACCUs. The government is proposing to limit total emissions from SGM facilities to 100 $MtCO_2e$ by 2030, a reduction of 27% from 2020/21 emission levels.

All liquefied natural gas (LNG) projects and most major coal mining activities fall under the SGM due to their carbon-intensive operations. In 2021, these accounted for 48% of SGM facility emissions. According to the government's projections, emissions from the LNG sector are expected to grow until 2035, while coal sector emissions are projected to decline only marginally, despite more ambitious government climate targets (Department of Climate Change 2022).

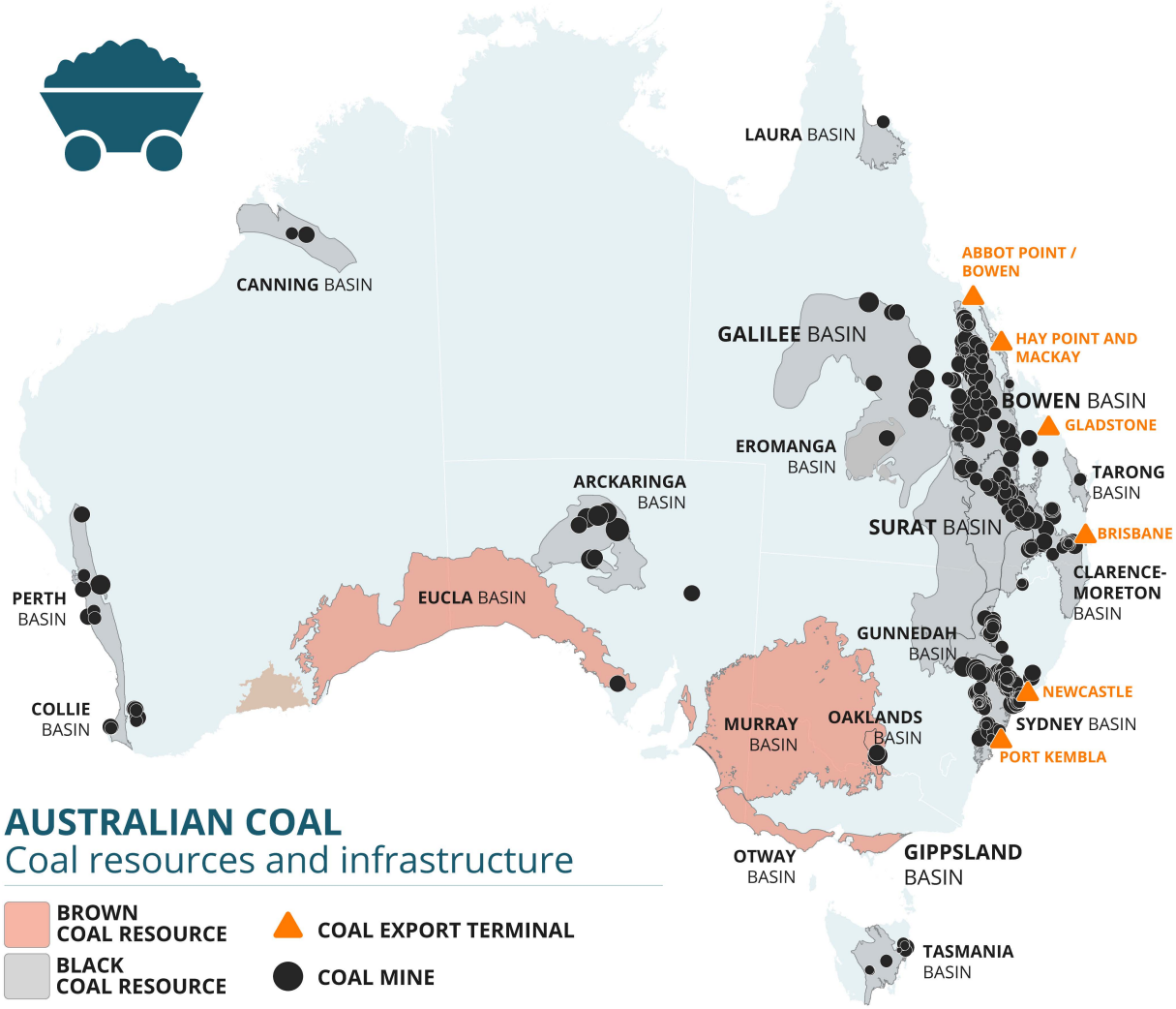

Figure 1: Map of coal mine and coal basins.

In the financial year 2020/21, 59 coal mines reported 31 $MtCO_2e$ of emissions under the SGM. Most of the coal Australia produces is sold on the international market; out of the 470 megatonnes (Mt) of coal produced in 2021, 78% was exported, making Australia the second largest coal exporter in the world behind Indonesia (IEA 2022b) According to the IEA, a rapid decrease in coal use both for power generation and industry is a necessary condition for reaching the net zero pledges adopted by around 140 countries (IEA 2021).

Australia currently has ten operational LNG plants and is the world's largest LNG exporter (Department of Industry 2022b). While fossil gas is touted by the gas industry as a transition fuel to help reduce reliance on coal, its continued use and expansion are inconsistent with the Paris Agreement's 1.5°C temperature goal. Analysis of 1.5°C compatible scenarios in the IPCC Special Report on 1.5°C shows unabated use of fossil gas in primary energy supply should already have peaked globally and be declining (Climate Analytics 2021). It needs to drop by more than 30% below 2020 levels by 2030, and 65% below 2020 levels by 2040.

The 2022 update of the IEA's Net Zero by 2050 Roadmap reinforces this, projecting that global gas use needs to be at least 30% below 2021 levels by 2030 to limit warming to 1.5°C (IEA 2022b).

The principal importers of Australia's LNG (China, Japan, South Korea, and Taiwan) all have net zero targets and will therefore be working to phase out fossil gas use. The IEA has shown that demand for Australia's LNG will likely peak within the present decade and decline rapidly to 25% below the 2020 level by 2030as LNG importing countries transition their energy systems away from fossil fuels, especially as cleaner, zero-carbon technologies can already be applied where fossil gas is presently used.

According to the Australian Government's projections, emissions from the LNG sector are expected to grow until 2030 due to increased production and more GHG-intensive resources, despite a commitment to more ambitious climate targets (Department of Climate Change 2022).

The Department of Industry, Science and Resources publishes an annual review of resources and energy projects with an estimated cost of over 50 million AUD and the potential to reach a final investment decision within the next five years (Department of Industry 2022a). The department classifies projects into three types: expansion, reactivations, and new projects. Expansion corresponds to an increase in capacity at an existing facility. New developments are greenfield projects. Reactivations are the reopening of previously existing facilities.

The government has four categories of project status:

1. **Publicly announced projects** are "usually very early in their development and are typically undergoing an initial feasibility study to assess the commercial aspects of developing an identified resource."
2. **Projects at the feasibility stage** "when the initial feasibility study for a project has been completed and the results support further development. Projects that have progressed to the feasibility stage have undertaken initial project definition studies and commenced more detailed planning work."
3. **Committed projects** that have "completed all commercial, engineering and environmental studies, received all necessary government regulatory approvals, and finalised the financing of the project to allow construction."
4. **Completed projects** at a stage where "all commissioning activities are completed, and the operation has reached commercial production."

The government counts 69 coal-related projects ranging from existing coal mine extensions or expansions to greenfield mine proposals. Except for the building of a second train at the Pluto facility, LNG-related projects largely involve changes in gas resources by opening new gas fields to replace declining output at existing fields. The review contains, 44 oil and gas projects, including 12 export-oriented LNG projects. In

this report, we investigate how these proposals affect the SGM reform in a context where all covered facilities share a single decreasing aggregate emissions baseline. Our analysis is based on the SGM as proposed in the position paper released in January 2023, the 2022 Emissions Projections and the 2022 Resources and Energy Major Projects report (Department of Climate Change 2022b, 2023; Department of Industry 2022a).

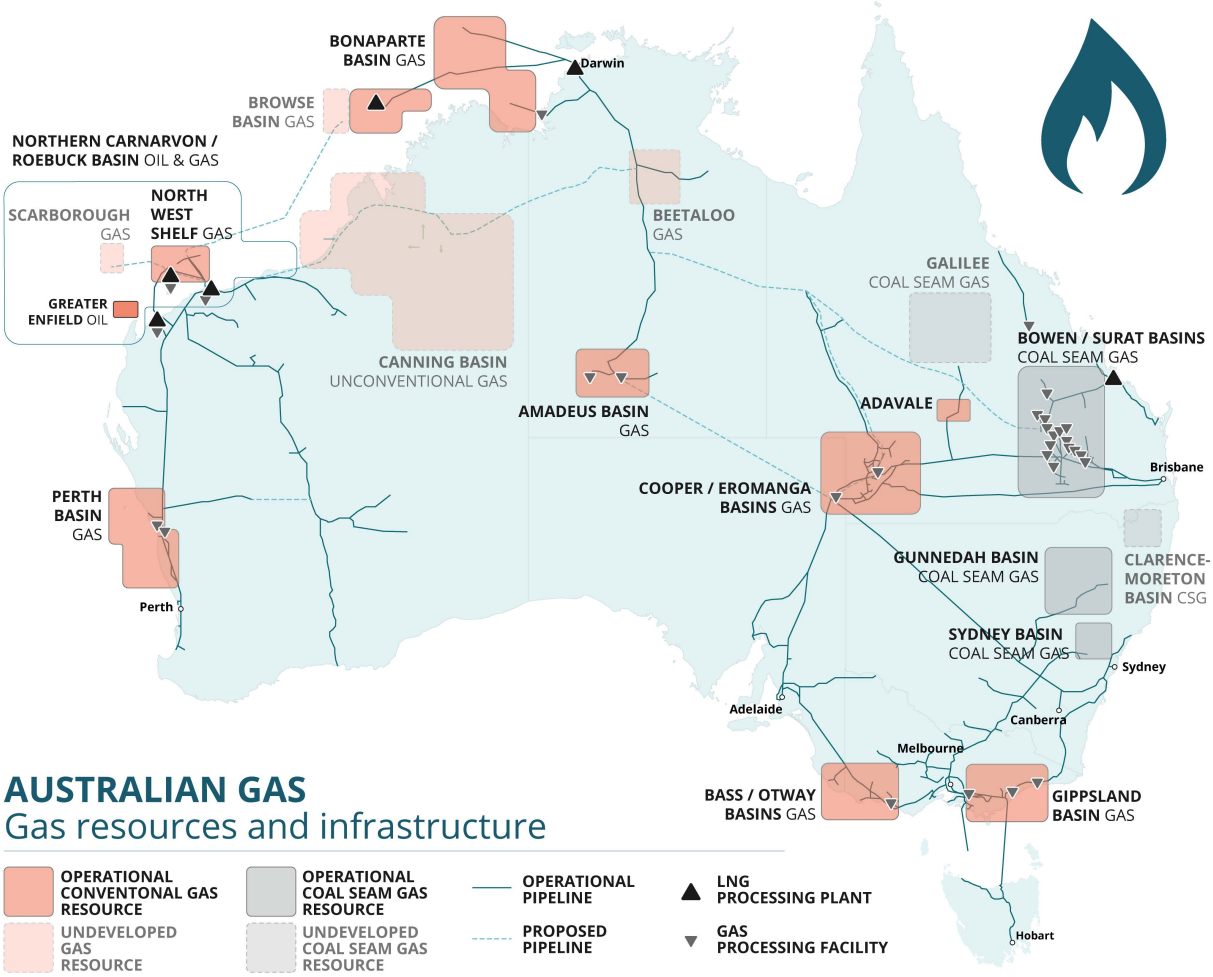

Figure 2: Map of gas pipelines, gas pipeline plans

Safeguard Mechanism reform

Importance of LNG and coal in the Safeguard Mechanism

The Australian government needs effective policy coverage for high-emission industries. Although the SGM was introduced in 2015, emissions from SGM-covered facilities increased year-on-year to reach 136 $MtCO_2e$ in 2020/21. The aggregate baseline for this year, however, was 180 $MtCO_2e$ which illustrates the urgent need for policy reform. The 213 facilities under the SGM account for 28% of Australia's emissions, with LNG facilities accounting for 25% of SGM emissions, and coal 23%.

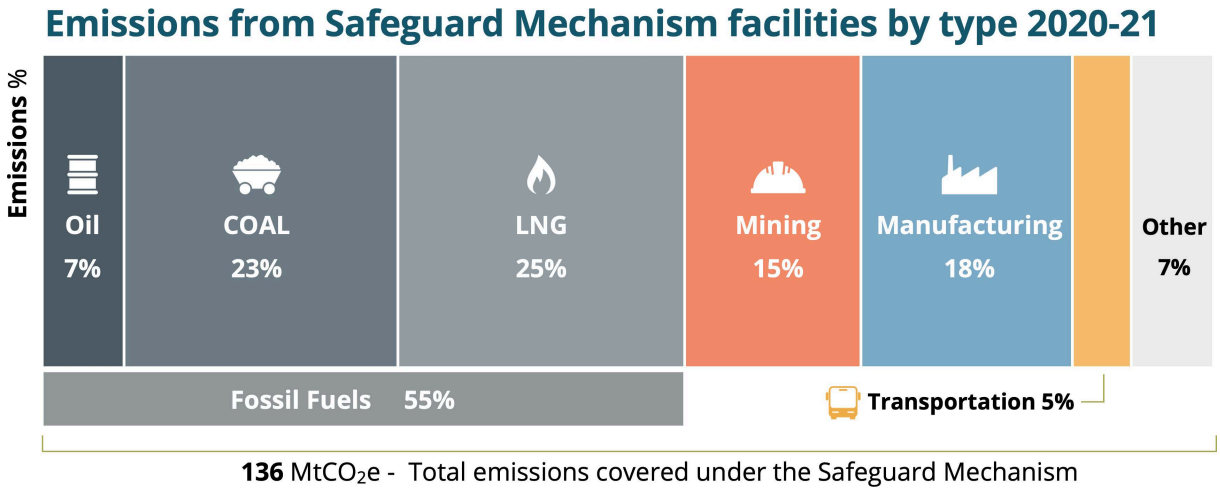

Figure 3: Emissions from the Safeguard Mechanism by type 2020/21.

Safeguard Mechanism reform

In its consultation paper and subsequent position paper, the government put forward proposals to make the SGM more effective.

Baseline contribution to Safeguard Mechanism emission reductions

In the original SGM, baselines were designed to follow a 'business as usual' emission scenario, in other words, to not reduce emissions at all.

To reach the government's economy-wide target of a 43% emissions reduction from 2005 levels by 2030, emissions from facilities covered by the SGM will need to reduce significantly by the end of the decade and contribute a proportionate share to the nation's overall emission abatement task.

To achieve this, the government has proposed the establishment of a binding baseline that reduces annually towards a limit of 100 $MtCO_2e$ by 2030, which SGM facilities will be required to reach collectively.

Starting in 2023/24, the reform will require a reduction in SGM facilities' emission ceilings at a base rate of 4.9% per annum. As part of this process, the government has

set a cumulative emission budget for SGM facilities from 2020/21 to 2029/30 of 1,233 $MtCO_2e$ with the decline rate set in such a way that the 100 $MtCO_2e$ limit is achieved in 2029/30 (see Figure *4*:).

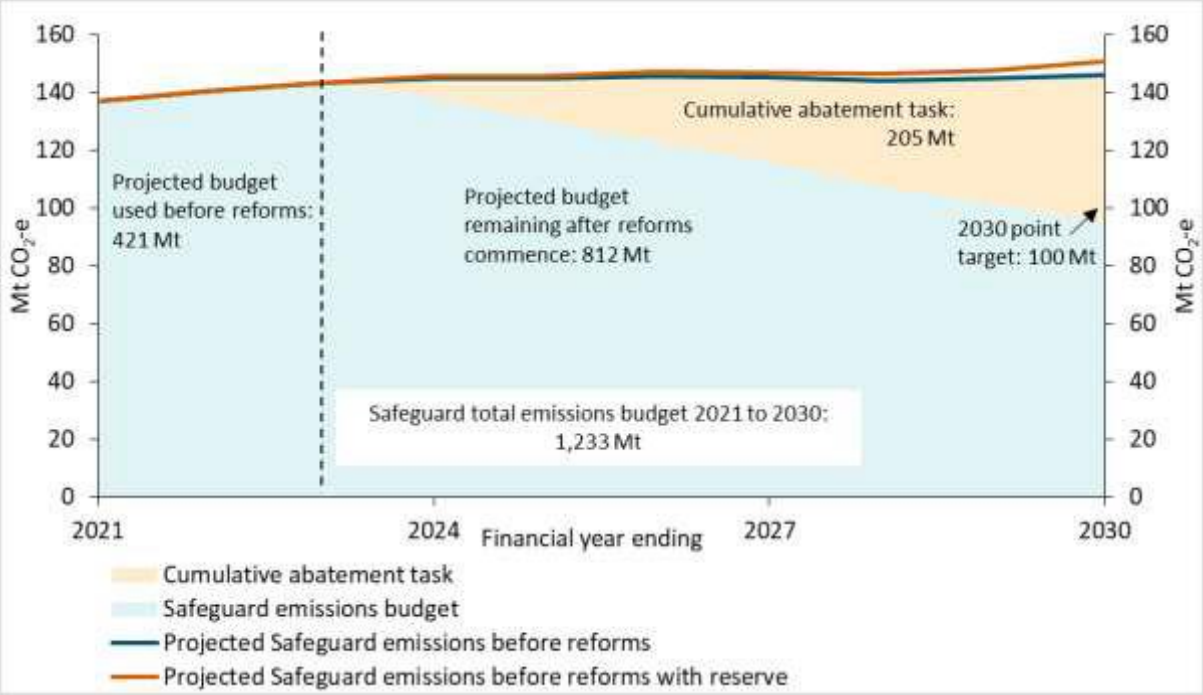

Figure 4: Proposed Safeguard emissions budget and target 2030 and abatement task. Source: Safeguard Mechanism Position Paper

In formulating the proposed SGM reforms, the government considered both industry-average and site-specific baseline approaches. Following a stakeholder consultation process, the government proposed that baselines would decrease according to a hybrid calculation model, progressively transitioning from site-specific to industry-average baselines. Starting in 2030, however, all baselines for existing facilities will be defined using industry average emission intensity only.

Box 3.1: Baseline setting under a hybrid approach

A simplified baseline setting formula for production-adjusted baselines using the hybrid approach is as follows (it doesn't take account of some policy elements described below, such as borrowing):

For all relevant production variables (or outputs):

$$\text{Facility baseline} = \Sigma \text{ Production } [(a \times EI_{IA}) + (b \times EI_{SS})] \times \text{decline factor}$$

Where the:

- **production variable** identifies the product or service being delivered, for example tonnes of alumina or passenger kilometres
- **EI_{IA} and EI_{SS}** are the industry average and site-specific emissions intensity of production, for example, emissions per tonne of alumina or emissions per passenger kilometre
- **a and b** represent the ratio of industry average and site-specific emissions-intensity values (where a + b = 1)
- **decline factor** reflects the cumulative decline rate (discussed in section 6)

With the following ratio of industry average to site-specific emissions-intensity values:

	2023-24	2024-25	2025-26	2026-27	2027-28	2028-29	2029-30
Weighting EI_{IA}:EI_{SS}	**10:90**	**20:80**	**30:70**	**40:60**	**60:40**	**80:20**	**100:0**

For example, using this simplified formula, in 2023-24:

$$\text{Facility baseline} = \Sigma \text{ Production } [(.1 \times EI_{IA}) + (.9 \times EI_{SS})] \times \text{decline factor}$$

Whereas, in 2028-29:

$$\text{Facility baseline} = \Sigma \text{ Production } [(.8 \times EI_{IA}) + (.2 \times EI_{SS})] \times \text{decline factor}$$

Figure 5: Baseline calculation method (Department of Climate Change 2023).

Stakeholders noted as part of the reform consultation process that industry-average baselines hold all facilities producing the same product to the same (ideally transparent) standard (Department of Climate Change 2023). They also incentivise industries to produce at less emission-intensive sites. However, as noted by Reputex, defining lower-than-average carbon-intensive facilities as 'clean' comes with pitfalls; by definition, industry average emission intensity benchmarks are a relative metric mostly dependent on fixed parameters like localisation (Reputex 2022). Since the datasets used for calculating industry averages are not available, in our analysis we calculated industry average emission intensity values derived from the SGM and government data. As site-specific data on production emission intensity is not available for coal mines, we estimated baselines using industry average values.

New facilities

The integration of new facilities which have not yet started production is a critical aspect of the reform design. With SGM facilities constrained by having to collectively reach 100 $MtCO_2e$ emissions by 2030, the addition of new entrants would increase the reduction needed from existing facilities above the average 27% implied by the 2030 emissions limit. It would also reduce the cumulative budget available to existing facilities. A reserve is embedded into the reform design to account for production variability and new facilities. It is, however, unclear how much carbon budget would be allocated for the reserve. The Department of Climate Change decided to set baselines for new entrants according to "best practices, adapted for an Australian context," but is yet to define exactly what constitutes the Australian context.

No new greenfield LNG facilities are coming online this decade, with increases in production coming from the expansion of existing facilities at Ichthys in 2024 and Pluto in 2026. Variations of LNG-related emissions are due to changes at currently operating facilities, like production capacity expansion or change of supply source.

Expansions of existing coal mines are considered here as existing SGM facilities, while new projects are considered as new SGM facilities. Without best practices emission intensity values adapted to the Australian context, our analysis is restricted to the industry average baseline for both existing and new facilities.

Emissions-intensive trade-exposed facilities

The reformed SGM provides a tailored treatment of emissions-intensive trade-exposed (EITE) businesses. As of January 2023, 80% of SGM-covered sites qualify as trade-exposed facilities. Such facilities are eligible to become trade-exposed, baseline-adjusted (TEBA) facilities if they fulfil certain conditions. The currently proposed criterion is purely financial: a cost impact metric calculated by dividing the scheme cost for a year (estimated with default certificate prices calculated yearly) by revenue. If that number exceeds a specific threshold, the facility receives a discounted baseline decline rate for three years, to which they can re-apply. The updated rate would be determined by the cost impact. This criterion is still under review. Considering its potential impact on the viability of certain industries, its determination is paramount to the scheme's viability.

TEBA facilities will get lower baseline decline rates depending on their cost impact metric, which means they will see their emissions reduction targets decrease at a slower pace than non-TEBA production sites. The minimum decline rate for such facilities is set at 2%, compared to the base 4.9%. All other things being equal, a TEBA facility for the period 2024-2030 would have its baseline reduced by 14%, compared to 34% with the default rate. This accommodation considerably reduces the emission reduction burden for TEBA facilities with the goal of preserving their international competitiveness. However, as the 100 $MtCO_2e$ target is shared by all SGM facilities, this reduced burden is transferred to other SGM facilities.

The main argument brought by the government in favour of the TEBA system is the prevention of carbon leakage (where an entity relocates its emitting activities outside the jurisdiction of a climate policy to save costs). While it is likely that LNG activities, and to a lesser extent coal activities, will get special treatment from the government as trade-exposed, they are actually at low risk of carbon leakage. In this analysis, we considered an extreme scenario where LNG and coal facilities get the maximum decline rate rebate (2% instead of 4.9%) between 2024 and 2030.

Coal mining emissions

Government projections

Emissions from all coal mining in Australia represented 8% of Australia's total emissions in 2020 and added up to about 41 $MtCO_2e$. Government projections indicate this share could increase to about 10% by 2030 (see Figure 5) although in these projections total coal mining-related emissions decrease to about 37 $MtCO_2e$ in 2030. Emissions from coal mining include fugitive emissions (mainly methane), and energy use in mining and production.

Fugitive emissions are the main source of coal mining emissions. The decomposition process which creates coal also produces carbon dioxide and methane that remains trapped in geological strata. Coal mining can cause this potent greenhouse gas to be released into the atmosphere via various means. In the same way that deeper repositories provide higher carbon-content coal, higher concentrations of methane occur at deeper levels. Due to their high methane content, underground mines are more carbon-intensive than their open-cut counterparts. They also continue to emit methane after their closure. Underground mines account for just 20% of coal mines in Australia yet are responsible for 70% of the industry's fugitive emissions. For a more in-depth breakdown of fugitive emissions, see Figure 3 below.

Stationary energy emissions related to coal mining were 10 $MtCO_2e$ in 2020 (Department of Climate Change 2022b) – 86% of the energy used in coal mining comes from diesel, the rest from electricity (Department of Climate Change 2022a). The latter accounted for 34% of coal's stationary emissions in 2020. Grid decarbonisation and electrification are therefore opportunities to drive down coal's stationary emissions.

The government's Powering Australia plan sets a target of 82% of renewables in the electricity market nationally by 2030. This objective is accompanied by the Rewiring Australia strategy, which aims to support the grid transformation necessary for the integration of high volumes of variable renewable energies and storage systems. Based on the baseline scenario from the grid-wide forecasts outlined in the government's 2022 projection, stationary electricity emissions per tonne of coal mined will halve by 2030 (Department of Climate Change 2022b).

A large part of this decrease is due to New South Wales's rapid electricity sector decarbonisation. In this state, which contains around half of the country's coal mines, electricity emissions are set to drop from 49 $MtCO_2e$ in 2020 to 8 $MtCO_2e$ in 2030. Grid decarbonisation is projected to be slower in Queensland and Victoria, with electricity emissions decreasing from 47 and 41 $MtCO_2e$ to 25 and 20 $MtCO_2e$ respectively over the same period.

Brown coal production is used in the power generation sector and accounts for less than 0.1% of the sector's fugitive emissions (Department of Climate Change 2022b).

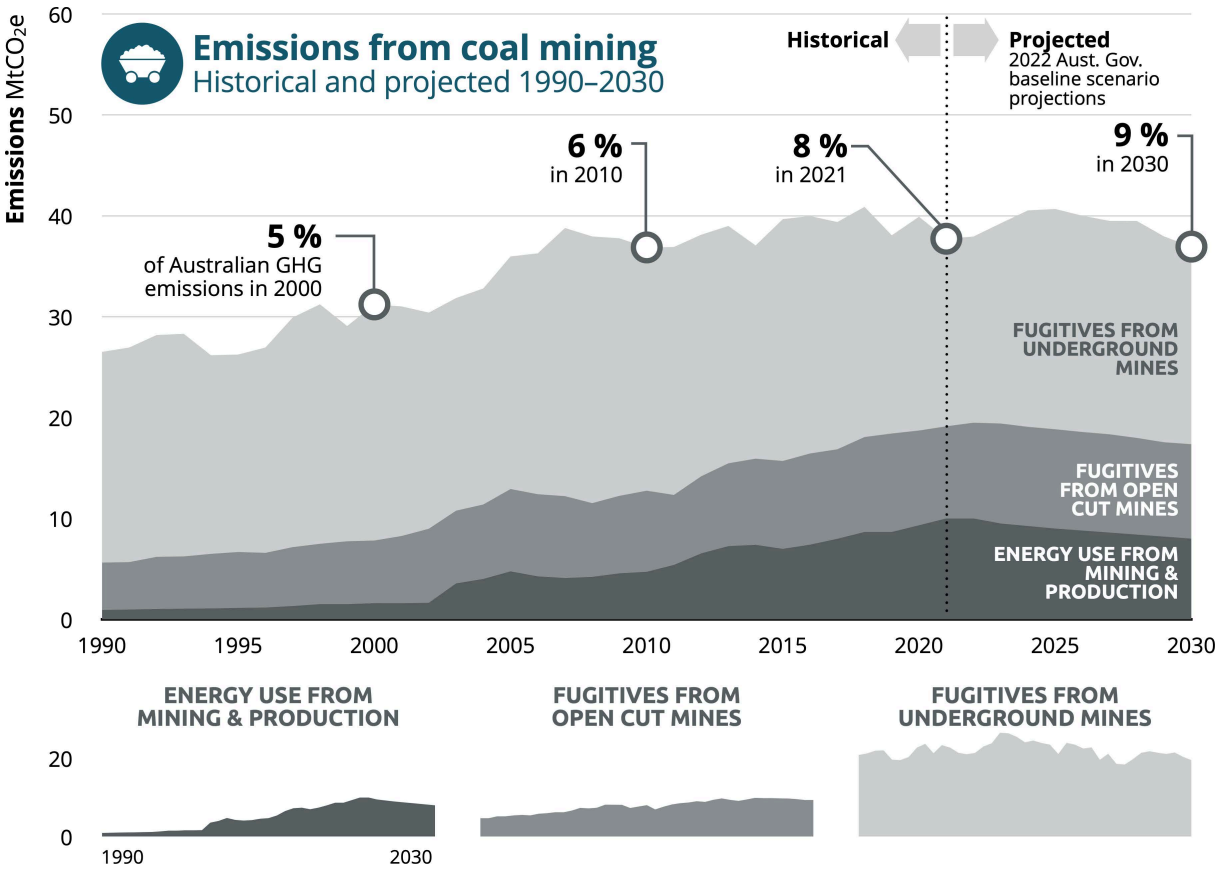

Figure 6: Coal mining emissions estimated by the government, from the 2022 Emissions Projections.

The government projections shown here are lower than we have estimated from the bottom-up analysis of the pipeline of coal mines, taking into account plant closures as well as committed expansions, proposed expansions and new mines and announced new mines under consideration, as discussed in this report.

Emissions from existing SGM coal facilities

The 59 coal mines currently under the SGM emitted 31 $MtCO_2e$ in 2020/21, 23% of emissions covered by the scheme.

All facilities are not equally carbon intensive. Seven coal mines are responsible for 30% of the sector's emissions, while 37 black coal mines are not included in the SGM as they do not meet the 100 $ktCO_2e$ annual emission threshold required to be included (Geoscience Australia 2022).

Coal production in 2020/21 was reduced due to extreme rainfall and flooding related to climate change. Floods in Queensland and New South Wales disrupted coal mine operations and their supply routes, leading to an 8% year-on-year output decrease (Department of Industry 2022b). To enhance the robustness of our analysis, we

averaged emissions data of existing mines over four years to balance out fluctuations such as the ones experienced in 2020/21.

According to publicly available information, a quarter of mines covered by the SGM currently in operation have an end-of-life date scheduled before 2030, meaning that unless extended they are due to close before the end of the decade. These mines emitted 5 $MtCO_2e$ in 2020/21. With increasing pressure from governments and civil society, coal extraction is likely to become less profitable for miners and more harmful to their corporate image, leading to a rise in anticipated closures. In December 2022, major mining company Glencore announced its plans to shut down 12 coal mines before 2035 to reach its emissions targets (Glencore 2022).

Emissions from extensions/expansions of existing SGM facilities and new projects

In this analysis, we considered projects start dates as reported by the authorities in the Major Energy and Resources projects review. Considering the high uncertainty regarding administrative approvals and construction hazards, the timeframe for the start of operations of new projects is likely to be underestimated by their proponents. Multiple projects have an estimated start date marked after 2028 as the government only considers developments likely to get a final investment decision in the next five years. Without further information, we assumed these projects come online in 2028 (the earliest timeframe) to assess their impact if they were to become operational before the end of the decade. This mostly concerns speculative projects at the feasibility stage or those that have been publicly announced.

In the same way, projects cancelled between the release of the Resources and Energy Major Projects review and the publication of this report, such as Central Queensland Coal, were excluded from the scope of the analysis (Jackson 2023). Among the government listing are projects that appear to be shelved – for example, projects that had early-stage approvals between 2010 and 2014 but have not been updated recently, or whose websites have been deleted. Their status – publicly announced or at the feasibility stage – demonstrates their lack of advancement and are therefore excluded from this analysis.

Expansion of existing facilities

Out of the 69 new coal projects listed by the Department, 23 are expansions of existing facilities. The government notes a "growing preference for expansions of brownfield sites over new greenfield investments, with an expanding list of lenders and investors withdrawing finance to new thermal coal projects."

If all projects become operational by 2030, these expansions of existing projects would on their own push total coal-related emissions to over 67 $MtCO_2e$, much more than current SGM coal emissions at 31 $MtCO_2e$. However, a lot of these projects are unlikely

to come online. If we only consider committed and completed mine expansions, coal-sector SGM emissions would reach 32 $MtCO_2e$ by 2030 after accounting for mine closures.

New projects

The pipeline of committed and completed new greenfield projects will add 6 MtCO2e per year. In total, emissions from existing facilities and all projects currently at the committed and operational stages are expected to reach 38 $MtCO_2e$ by 2030.

Expansion and greenfield projects currently at the feasibility stage would, if they were all developed, emit 22 $MtCO_2e$ in 2030. Mines publicly announced, for which actual completion is highly speculative, would account for a further 7 $MtCO_2e$. In the most extreme scenario where all the pipeline projects get developed, coal emissions could reach 67 $MtCO_2e$ in 2030, more than two-thirds of the total SGM emissions permissible under the reform.

With a baseline declining every year at a fixed rate, the SGM becomes a zero-sum game as the emission ceiling is shared among all participants. When an industry's share increase, another sector's allowance decreases. We can define an industry's fair share as its current proportion of SGM emissions - coal's fair SGM share is therefore 23%. If that share remains stable until 2030, emissions from the coal sector would decrease to 23 Mt. Total run-of-mine black coal production is forecast to reach 560 Mt in 2030 after spiking at 602 Mt in 2025, up from 563 Mt in 2020 (Department of Climate Change 2022b). Using values from the government, the industry-average baseline for the entire coal sector decreases to 22 Mt in 2030. In all coal development scenarios, the industry largely exceeds both its 2030 allocated baseline and fair share.

The only way for coal-related emissions not to diverge from the trend set by the decreasing SGM baseline is to not develop any project, whether greenfield or expansions. The scheduled closure of coal mines, without considering expansion plans, would decrease emissions from existing facilities to 25 $MtCO_2e$, still leaving a 3 Mt gap between actual emissions and the current share of coal emissions in the SGM.

About 84% of Australia's thermal coal is exported, mainly to East Asia. In the extreme case where all coal mines get the trade-exposed, baseline adjusted minimum decline rate of 2%, coal sector emissions would represent 29% of the SGM's total emissions. The 6 $MtCO_2e$ gap between its fair share and the baseline would have to be absorbed by other sectors. The difference between the industry-average baseline and the trade-exposed adjusted one provides a range of plausible aggregate baselines for the sector in 2030.

Coal production forecast variability is higher for coal than LNG due to the abundance of new and existing projects – a consequence of the lower capital investments required for coal mining. Between the best-case (where no new mines and expansions come online) and worst-case scenarios (where all the projects in the pipeline get developed), carbon

dioxide equivalent emissions are almost three times higher. What is clear is that Australian coal production and emissions are not aligned to a 1.5°C-compatible global coal phaseout scenario or the expected decrease in demand from international trading partners.

Coal megaprojects

The average and median capacity of coal projects in the pipeline are 6.9 and 4.2 Mtpa respectively. 82% of their emissions would be fugitive emissions, the remainder being energy use emissions. Even though 49 new projects out of 69 are open-cut, 73% of additional emissions would come from underground projects.

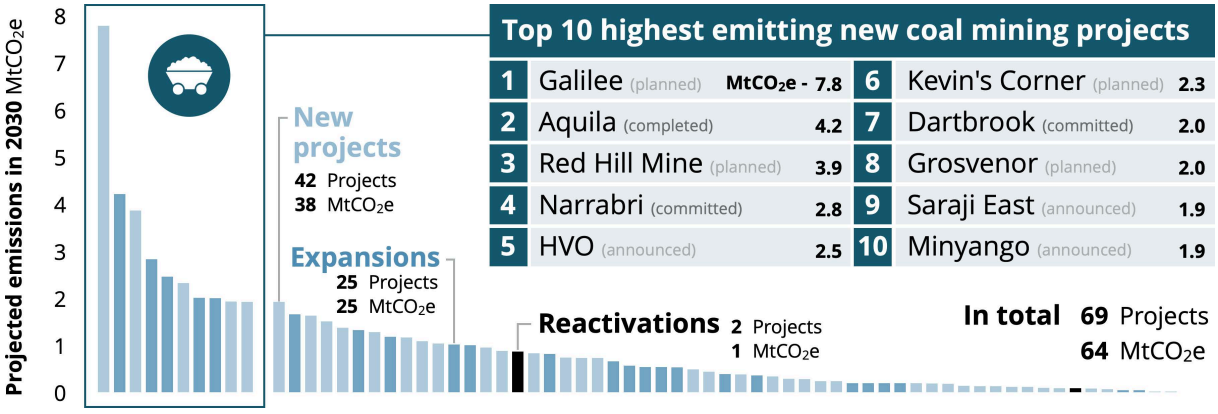

Figure 7: Top 10 highest emitting new coal projects.

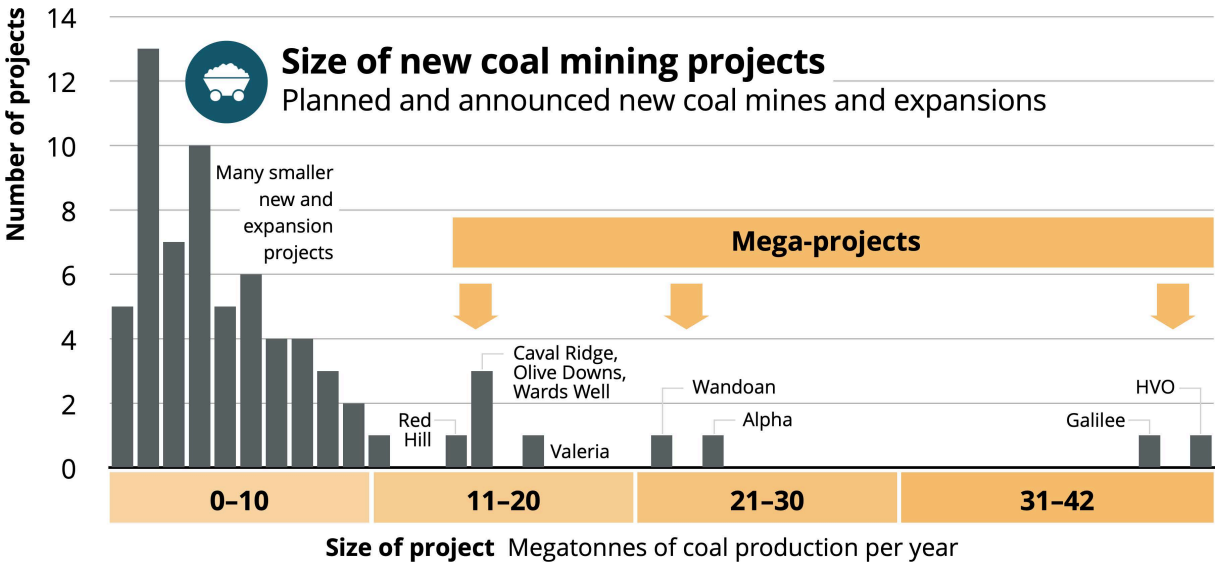

Figure 8: Number of proposed new coal projects by size

Among developments still in their infancy, two 'megaprojects' have planned annual capacities above 40 Mtpa each, close to 10% of Australia's current black coal production. The HVO Continuation project, which has been publicly announced, is being developed by Yancoal and Glencore. It comprises the lifetime extension of two open-cut mine sites across the Hunter River.

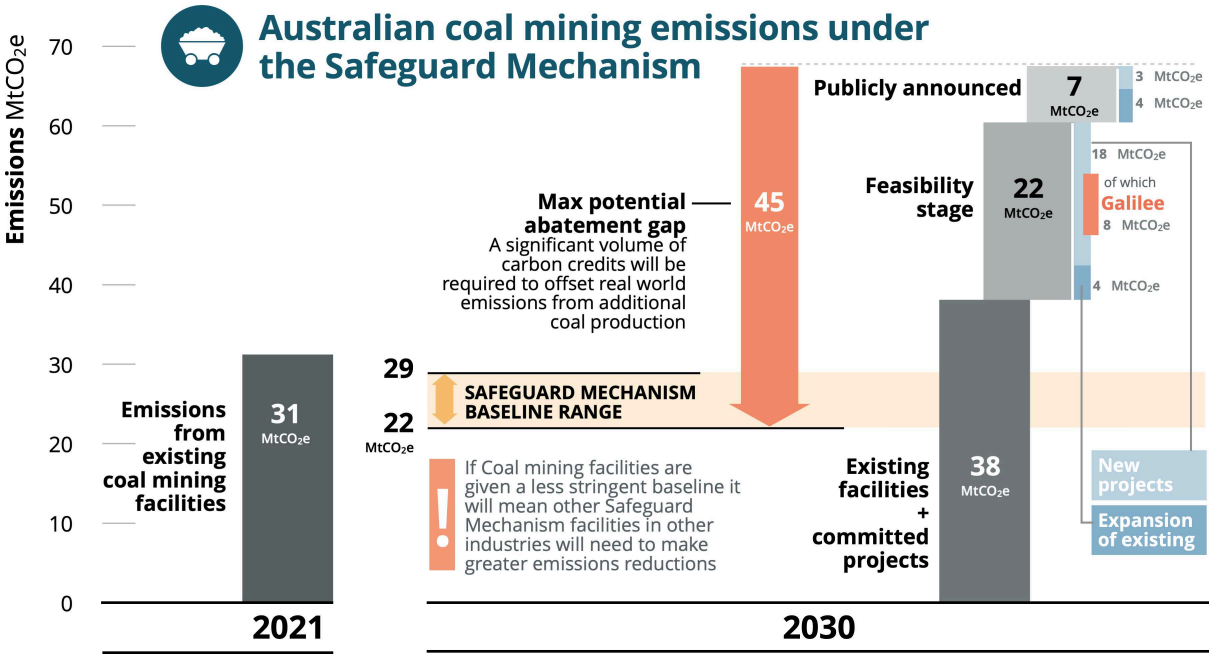

Figure 9: Coal emissions under the Safeguard Mechanism.

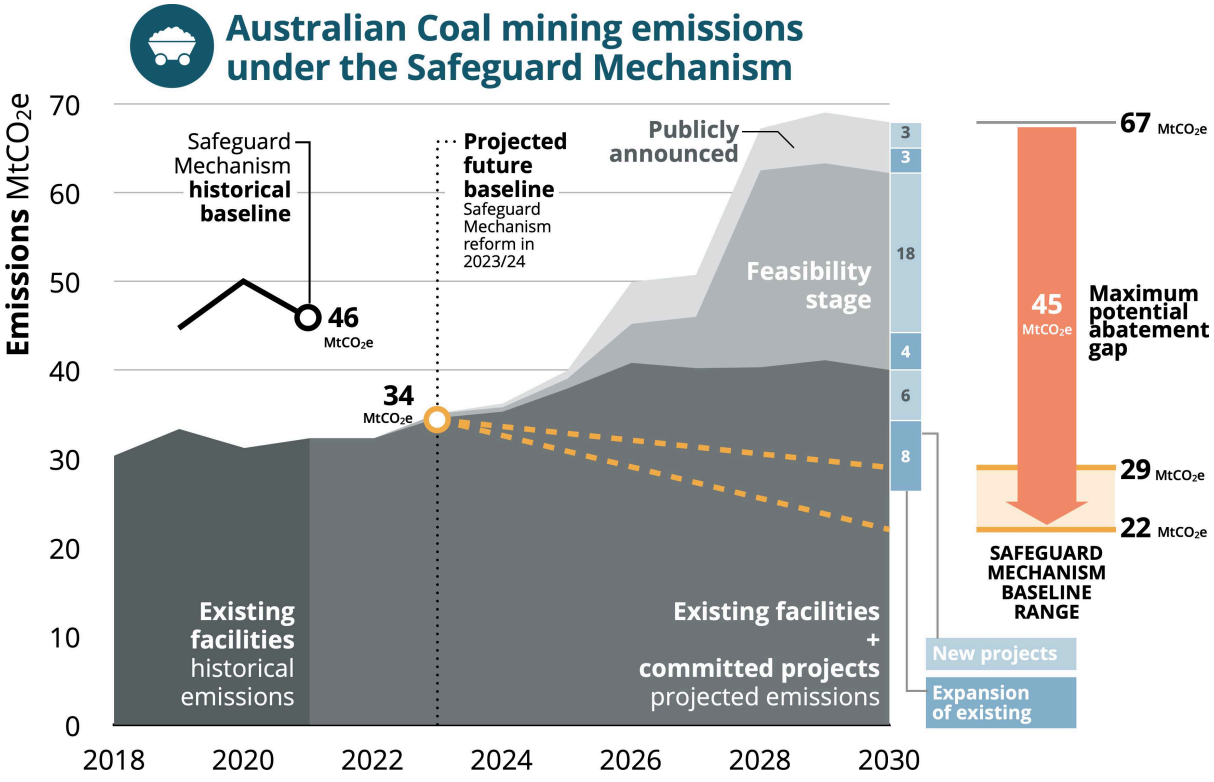

Figure 10: Coal emissions under the Safeguard Mechanism.

Galilee, proposed by Waratah, is a greenfield project currently at the feasibility stage. As part of a case filed by Youth Verdict in November 2022, Queensland Land Court President Fleur Kingham recommended the project be rejected. Kingham argued that "in relation to climate change, [she] has found that the following rights of certain groups of people in Queensland would be limited: the right to life, the cultural rights of First Nations peoples, the rights of children, the right to property and to privacy and home, and the right to enjoy human rights equally" and that "the costs of climate change to people in Queensland, to which combustion of coal from the project will contribute, have not been fully accounted for" (Hinchliffe and Smee 2022).

Most of the coal mined at Galilee will be extracted underground. If developed, the Galilee Project would emit 8 $MtCO_2e$ per year, including 7 $MtCO_2e$ of fugitive emissions. Its carbon footprint would be twice the size of the Capcoal mine, the SGM's current most emitting coal facility.

In a paper published in May 2022, researchers found that even under the most optimistic assumptions, new coal developments in the Galilee Basin would not be economically viable and are at risk of becoming stranded assets (Hauenstein et al. 2022). When it was initially proposed in 2010, the Carmichael project, also in the Galilee Basin, was supposed to become the biggest coal mine in the world with an annual capacity of 60 Mtpa. The mine has since been considerably downsized as it failed to attract investment. Carmichael mine started its commercial operation in late 2021 with an annual capacity of 10 Mtpa amid high economic uncertainty (Hauenstein et al. 2022). The Galilee project faced the same challenges. More generally, all new coal developments in this decade will come online at odds with global trends. In its net-zero emission scenario, the IEA forecasts that global coal demand drops by 45% in 2030 compared to 2021 levels (IEA 2022b).

Table 1: Coal mining facilities under the Safeguard Mechanism, emissions ($MtCO_2e$).

Coal mine projects	2021	2030	Change 2021-2030	Abatement gap range	
	$MtCO_2e$	$MtCO_2e$	Percentage	**Industry-average** adjusted baseline $MtCO_2e$	**Trade-exposed** min. decline rate baseline $MtCO_2e$
Emissions from existing facilities	31	25	-19%	4	-2
Incl. committed & completed expansions		32	3%	10	3
Incl. committed & completed new projects		38	23%	16	9
Incl. expansions at the feasibility stage		42	35%	20	13
Incl. new projects at the feasibility stage		60	94%	38	31
Incl. expansions publicly announced		65	110%	43	36
Incl. new projects publicly announced		67	116%	45	38
Baselines					
Industry-average adjusted baseline		22			
Trade-exposed min. decline rate baseline		29			

Abatement gap

The abatement gap between coal emissions and baselines is highly variable, as many production ramp-up pathways remain open for the sector this decade. Due to the lack of site-specific emission intensities, we assumed that baselines would be based on industry average values from the start of the reformed scheme to 2030. In the actual reform, baselines shift from predominantly site-specific to average on industry benchmarks as outlined in the section on the Safeguard Mechanism reform.

The cumulative abatement gap between the industry-average baseline and coal emissions from existing mines, completed and committed expansions and new projects are 46 $MtCO_2e$. It increases to 184 $MtCO_2e$ if we account for all new coal projects, including at the feasibility and publicly announced stage. With this baseline, the abatement gap from the coal sector would represent between 22% and 89% of the 205 $MtCO_2e$ total abatement that the reform is supposed to deliver.

If all coal mines receive trade-exposed adjusted baselines, the abatement gap range falls between 24 $MtCO_2e$ and 160 $MtCO_2e$, 11% and 78% of total abatement. Given its range of potential developments, the evolution of coal production will be determinant for the reform's ability to incentivise emissions reductions.

LNG emissions

The present global energy crisis has prompted both the government and Australian gas companies to reinvigorate support for the expansion of LNG production, in continuation of the government's record of supporting the oil and gas industry. However, in its 1.5°C-aligned net-zero roadmap, the IEA projected a collapse in global LNG trade, with Australian LNG exports projected to drop faster than the international average (Climate Analytics 2021).

Government projections

LNG production capacity and exports have risen rapidly over the last decade. They are projected to grow 6% and 14% respectively from 2021 levels by 2030, adding 6-7 $MtCO_2e$ emissions (16%-20% higher than 2020/21 levels). Figure 11 shows considerable growth in LNG production capacity and exports from 2015, from around 20 Mtpa of LNG to almost 90 Mtpa of LNG capacity by 2020.

The Australian government projects LNG production will increase from close to 80 Mtpa of LNG in 2020 to about 88 Mtpa of LNG by 2030 with a nominal nameplate capacity totalling 93 Mtpa of LNG.

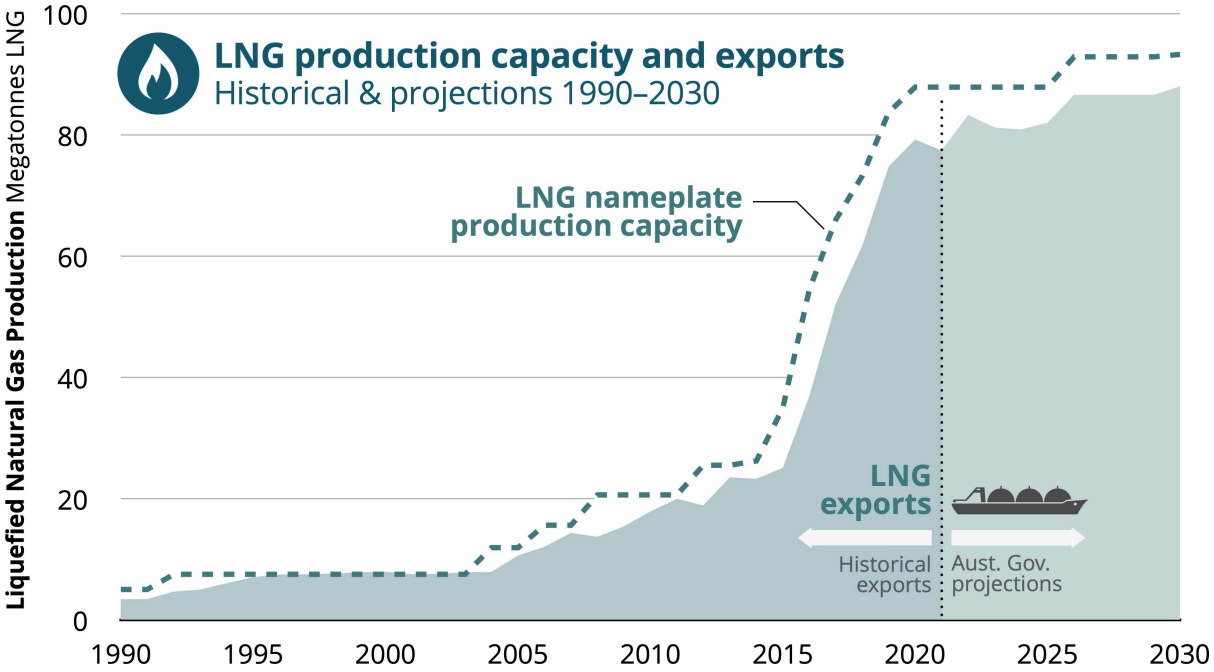

Figure 11: LNG production capacity and government projections of exports – historical to 2022 and projected to 2030.

Source: 1991-2022 export data from Resources and Energy Quarterly September 2022 Historical Data.

Figure 12 shows that total LNG emissions were 7% of Australia's emissions in 2020. In the government's baseline scenario where emissions decrease by 32% below 2005 levels, an increase in LNG production from more carbon-intensive fields will result in LNG accounting for a projected 10% of domestic emissions by 2030 in the context of an overall reduction in national emissions. The government's baseline scenario does not consider the SGM reform and some measures of the Power Australia Plan. These measures are supposed to fill some part of the gap between the baseline scenario's 32% emissions decrease below 2005 levels, and the 43% target set in June 2022.

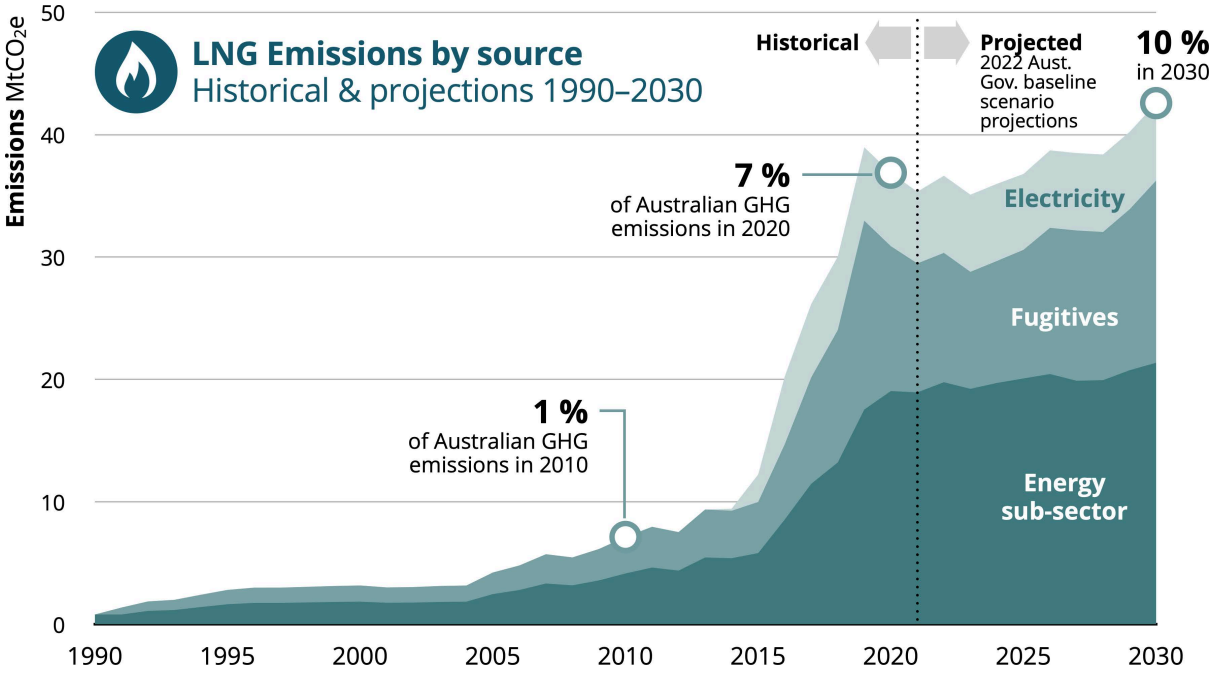

Figure 12: LNG emissions – historical to 2022, projected to 2030.

LNG facilities accounted for 25% of SGM emissions in 2020/21, at 33 $MtCO_2e$.

The LNG emissions reported in the SGM differ from government projections as LNG facilities process gas for the domestic market and produce by-products, such as condensate or liquid petroleum gas (LPG). Western Australia's reservation policy stipulates that 15% of the equivalent output from LNG plants must be made available for domestic consumption (Government of Western Australia 2021).

LNG-related GHG emissions are categorised into fugitive, stationary and electricity emissions. Fugitive emissions are the release of greenhouse gases during fossil fuel production, processing, transportation and storage. For LNG, a large part of fugitive emissions come from reservoir CO_2. Gas reservoirs have varying levels of CO_2, which in general needs to be removed before the gas can be processed. Typically, in Australian LNG production, CO_2 is vented into the atmosphere with one exception, Chevron's Gorgon project in Western Australia (see section below on the significance of fugitive emissions for further details).

Stationary energy emissions include GHG release from energy – mainly gas – used in the production and transmission of offshore gas, and fossil gas used in the LNG manufacturing process. Electricity used for LNG also has associated emissions, as electricity use in the sector is principally found in Queensland in coal seam gas (CSG) based LNG plants.

Of the 35 $MtCO_2e$ of GHG emissions arising from the LNG industry in 2020/21 according to the government's projections, around 19 $MtCO_2e$ comes from stationary energy, 11 $MtCO_2e$ from fugitive emissions and 4 $MtCO_2e$ from electricity use (Department of Climate Change 2022b). We estimate reservoir CO_2 emissions in 2020/21, factoring in carbon storage at Gorgon, to have been in the range of 8.5-11 $MtCO_2ee$.

These categories only account for emissions caused by LNG production. Final consumption, either for power generation, chemical manufacturing or for heating, is the main driver of fossil gas climate impact.

For the LNG sector, electricity, and stationary energy emissions, which relate to the energy needed to extract and process fossil fuels, were respectively 6 $MtCO_2e$ and 18 $MtCO_2e$ in 2019/20.

LNG-related stationary emissions are projected to increase by about 12% between 2020 and 2030. Emissions from electricity use are expected to remain relatively stable until 2030, or slightly decline depending upon the rollout of renewable energy during this decade. Changes in gas sources to reservoirs with higher CO_2 content will cause a significant increase in fugitive emissions (see the significance of fugitive emissions section below).

Emissions of all LNG projects (existing, expansions) under the Safeguard Mechanism

2030 emissions from infrastructure in their current state were derived using a multi-year approach, accounting for disruptions. The Shell Prelude plant, for example, produced just over half of its nameplate capacity in 2020/21 due to outages, while the Wheatstone plant production exceeded its nameplate capacity.

Around half of Australia's LNG facilities are likely to undergo modifications before 2030. The building of a second train at Pluto will connect to production at the Scarborough field (Hare et al. 2021). Ichthys' nameplate capacity will increase from 8.9 to 9.3 Mtpa of LNG in the late 2020s. Gas from Crux will backfill the Prelude facility, which will be renovated. The Browse Basin will supply gas to the North West Shelf plant.

After the depletion of the Bayu-Undan gas field, Santos plans to start extracting gas from the Barossa field, one of the most CO_2-intensive fossil gas reservoirs in the world (Robert 2022). We considered gas production in Barossa starting in 2025 as planned by Santos, despite the recent court decision regarding the field (Santos 2022). The Darwin plant is assumed to go offline between 2023 and 2024. Emission numbers from Barossa

and subsequent adjustments at the Darwin LNG facility come from the original proposals from ConocoPhillips (ConocoPhillips 2018, 2020).

The increase in LNG-related emission come from modifications of existing projects only.

Apart from the Pluto Train 2 expansion and the scale-up of the Ichthys plant, no new LNG production capacities are expected to come online before 2030. The projected increase in LNG-related emissions is mainly due to the changeover from current gas fields to new basins with higher CO_2 content.

All such modifications of existing projects are included in the government's projections, suggesting they are taken for granted by the government. We consider them as committed in our analysis, which uses the same start of operation date as the Resources and Major Projects review. For details on the inclusion of CCS, see dedicated section.

If all the plant changes in the pipeline proceed, LNG-related emissions will increase significantly by 12 $MtCO_2e$ between 2021-2030 to reach 45 Mt. Browse to North West Shelf and Barossa to Darwin alone will increase Australia's emissions by more than 7.2 $MtCO_2e$ per year. The production-weighted carbon intensity of Australian LNG is expected to rise by 21% from 0.43 tCO_2e per tonne of LNG to 0.52 tCO_2e per tonne of LNG between 2021 and 2030. All the LNG facilities undergoing supply source change in the coming years will produce LNG with a higher-than-average carbon intensity, making their output less attractive to trading partners seeking less polluting fuels.

Table 2: LNG facilities, emissions, production, emissions intensity, status and planned changes.

Facility	State	Owner(s)	Emissions 2020/21 $MtCO_{2e}$	Projected emissions from currently operating infrastructure in 2030 MCO_2e	Additional emissions in 2030 $MtCO_2e$	Production in 2030 MtLNG	Emissions intensity in 2021 $tCO_2e/tLNG$	Emissions intensity in 2030 $tCO_2e/tLNG$	Status	Changes
Wheatstone Operations	WA	Chevron (64.14%) KUFPEC (13.4%) Woodside (13%) PE Wheatstone (8%) Kyushu Electric (1.46%)	4	3.4	0	8.4	0.41	0.41	Existing project	No change assumed
Gorgon Operations	WA	Chevron (47.3%) ExxonMobil (25%) Shell (25%) Osaka Gas (1.25%) Tokyo Gas (1%) JERA (0.417%)	5.5	7.2	-0.4	14.7	0.49	0.46	Existing project	In 2021, the Gorgon CCS facility underperformed. For the following years, we assume that it will perform as intended.
Pluto LNG	WA	Woodside (90%) Tokyo Gas (5%) Kansai Electric (5%)	1.9	1.8	1.9	9.3	0.39	0.40	Expansion of existing project	The Karratha LNG processing plant will add another processing train (Pluto Train 2) by 2026.
North West Shelf Project	WA	Woodside (33.33%) BP (16.67%) Chevron (16.67%) MIMI (16.67%) Shell (16.67%)	6.8	7.2	3.8	16	0.45	0.69	New gas field	The Browse to North West Shelf project will come online in 2028/29.
Prelude FLNG	WA	Shell (67.5%) Inpex (17.5%) KOGAS (10%) CPC (5%)	1.5	2.5	0.5	3.4	0.74	0.88	New gas field	The Crux field will backfill Prelude starting 2027.
Ichthys LNG	NT	Inpex (66.245%) Total (26%) CPC (2.625%) Other (5.13%)	6.4	6.7	0.3	8.8	0.79	0.79	Expansion of existing project	Scaling up of production from 8.9 Mtpa to 9.3 Mtpa by 2024.

Facility	State	Owner(s)	Emissions 2020/21 $MtCO_{2e}$	Projected emissions from currently operating infrastructure in 2030 MCO_2e	Additional emissions in 2030 $MtCO_2e$	Production in 2030 MtLNG	Emissions intensity in 2021 $tCO_2e/tLNG$	Emissions intensity in 2030 $tCO_2e/tLNG$	Status	Changes
Darwin LNG Plant	NT	Santos (43.4%) SK E&S (25%) INPEX (11.4%) Eni (11%) JERA (6.1%) Tokyo Gas (3.1%)	1.6	1.7	3.1	3.5	0.47	1.37	New gas field	Bayu-Undan will come to the end of its field life in 2022/23. Barossa gas will be used as a replacement.
APLNG Facility	QLD	ConocoPhillips (47.5%) Origin Energy (27.5%) Sinopec Group (25%)	2.1	2.1	0.0	8.5	0.25	0.25	Existing project	No change assumed.
Queensland Curtis LNG Plant	QLD	Train 1: Shell (50%) CNOOC (50%) Train 2: Shell (97.5%) Tokyo Gas (2.5%)	1.8	1.9	0.0	8	0.23	0.23	Existing project	No change assumed.
Curtis Island GLNG Plant	QLD	Santos (30%) Petronas (27.5%) TotalEnergies (27.5%) KOGAS (15%)	1.7	1.8	0.0	7.4	0.25	0.25	Existing project	No change assumed.
Total			**33.3**	**36.3**	**9.3**	**88**	Production weighted average: **0.43**	Production weighted average: **0.52**		

Sources: 2020/21 emissions from the Safeguard Mechanism data, production derived from Western Australia LNG profile and available data (WA Government 2022).

Safeguard Mechanism

Considering the government's production forecasts, the SGM industry-average baseline for LNG facilities is calculated to be 25 $MtCO_2e$ in 2030, a 24% decrease compared to the sector's 2021 emissions (33 $MtCO_2e$). This would keep LNG-related emissions in line with their current share of the SGM at 25%. The industry would have to balance reaching these reduction targets with expanding production and the exploitation of increasingly carbon-intensive fields.

The government proposes to allow trade-exposed facilities to receive baseline adjustments. The LNG sector appears likely to seek and get these beneficial accommodations. For eligible facilities, the minimum baseline decline rate would be 2% per year. In a worst-case scenario where all LNG facilities were approved to use the minimum baseline decline rate of 2%, the LNG sector baseline would be 33 $MtCO_2e$ in 2030, similar levels to the sector's current SGM emissions. The LNG industry would then represent one-third of the scheme's baseline emissions.

The SGM reform paper indicates a reserve is built into the SGM baseline for higher-than-expected production growth at new and existing facilities, and trade-exposed baseline adjustments. However, the trade-exposed baseline is 8 $MtCO_2e$ higher than the industry average. Therefore, the more LNG facilities approved for a lower baseline, the more SGM facilities in other industries must compensate.

Table 3: LNG emissions between 2021 and 2030 ($MtCO_2e$).

LNG Project Emissions				**Abatement gap range**	
	2021 $MtCO_2e$	**2030** $MtCO_2e$	**Percentage change 2021-2030**	**Industry-average adjusted baseline** $MtCO_2e$	**Trade-exposed min. decline rate baseline** $MtCO_2e$
SGM Existing LNG facilities	33	36	9%	11	3
Incl. additional emissions		45	36%	20	12
Baselines					
Industry-average adjusted baseline		25			
Trade-exposed min. decline rate baseline		33			

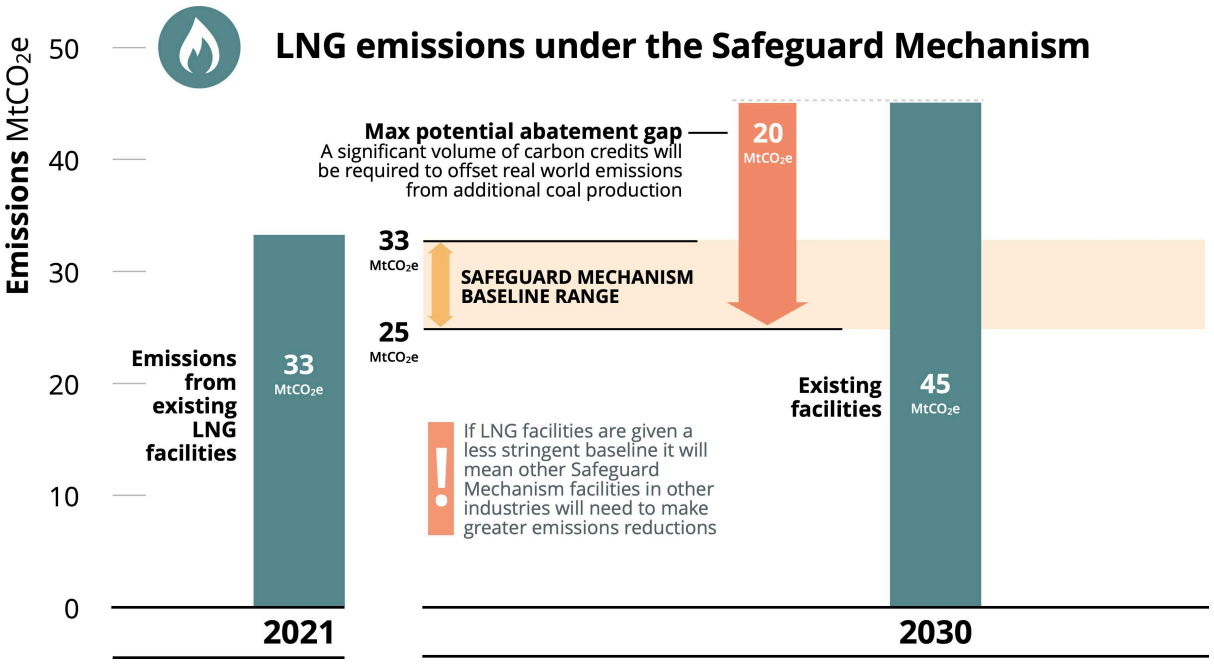

Figure 13: LNG emissions under the SGM

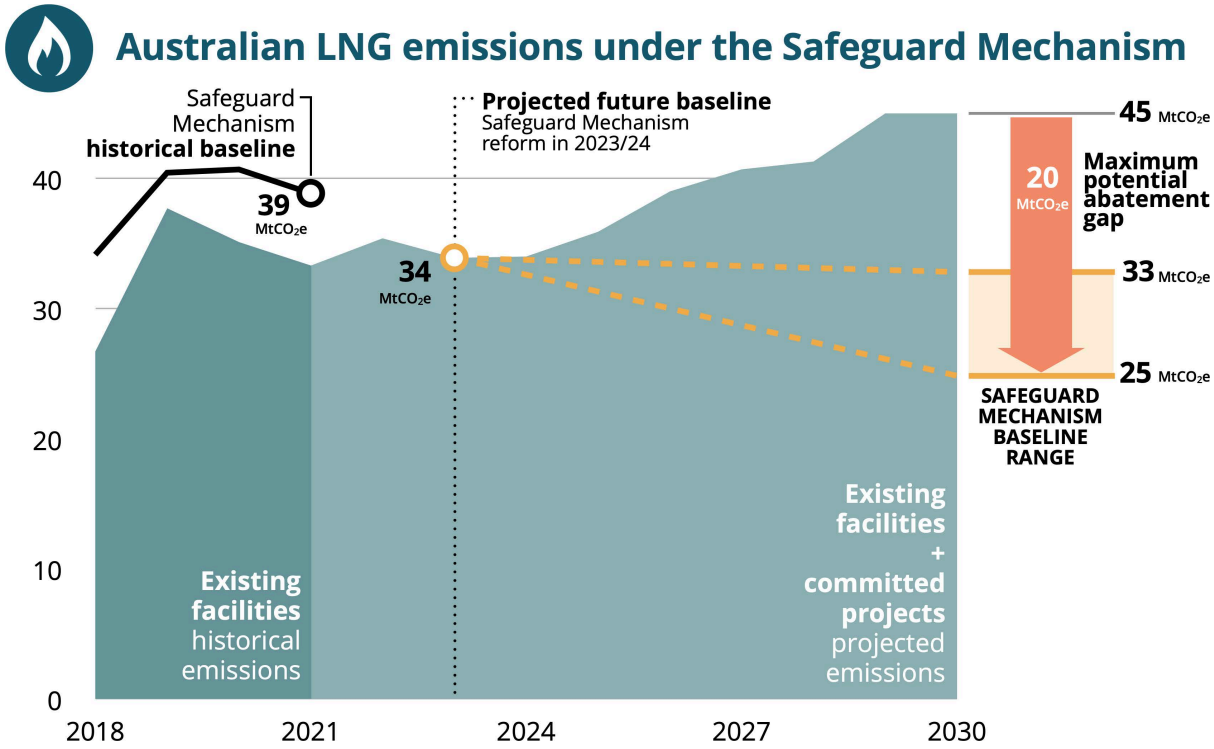

Figure 14: LNG emissions under the SGM

Cumulative Abatement gap

Between the proposed start of the SGM reforms in mid-2023 and 2030, the cumulative abatement gap between estimated LNG emissions and an industry-based average baseline will reach 75 $MtCO_2e$. If all LNG facilities receive trade-based adjusted baselines, the gap decreases to 49 $MtCO_2e$. That would represent between 24% and 37% of the total cumulative abatement gap delivered by the Safeguard Mechanism reform until 2030. See the abatement gap section for further details.

Implications of coal mining and LNG emissions on the Safeguard Mechanism

The pathways detailed in the report show that in all scenarios, the share of coal and LNG in the SGM increase. The government has guaranteed it will not go back on the 100 $MtCO_2e$ limit in 2030 planned for the scheme, an essential instrument in reaching Australia's emission reduction goal by 2030.

Since this emission ceiling is shared across all sectors, any increase in emission from a specific sector would reduce the emissions allowance for other sectors. If just the currently committed expansions and new projects go ahead, we calculate LNG and coal-related emissions to increase by 36% and 23% respectively between 2021 and 2030. Under this scenario, with SGM emissions needing to decrease by 4.9% overall each year starting from 2024, an additional burden of emission reductions will be transferred to other industries.

Thanks to the limited number of LNG projects and their large scales, we have relatively good visibility of likely LNG-related emissions until 2030. Coal is the main source of uncertainty in forecasting how SGM fossil fuel emissions will evolve this decade.

In 2030, if all coal projects in the present pipeline were to be developed, coal sector emissions would increase by 36 $MtCO_2e$ above 2021 emission levels. This is more than the total current LNG-related emissions.

Among new greenfield projects at their early stages, a few projects stand out. Galilee, Clive Palmer's controversial coal extraction project, could generate 8 $MtCO_2e$ per year alone in domestic emissions by 2030.

Emissions from existing and committed LNG projects and all coal projects from committed expansions through publicly announced add up to 113 $MtCO_2e$ per year in 2030, more than the total baseline target set for all facilities under the SGM. This would leave no room for other facilities. In other words, the expansion of coal mining along with changes in LNG production and gas resources could effectively make or break the SGM.

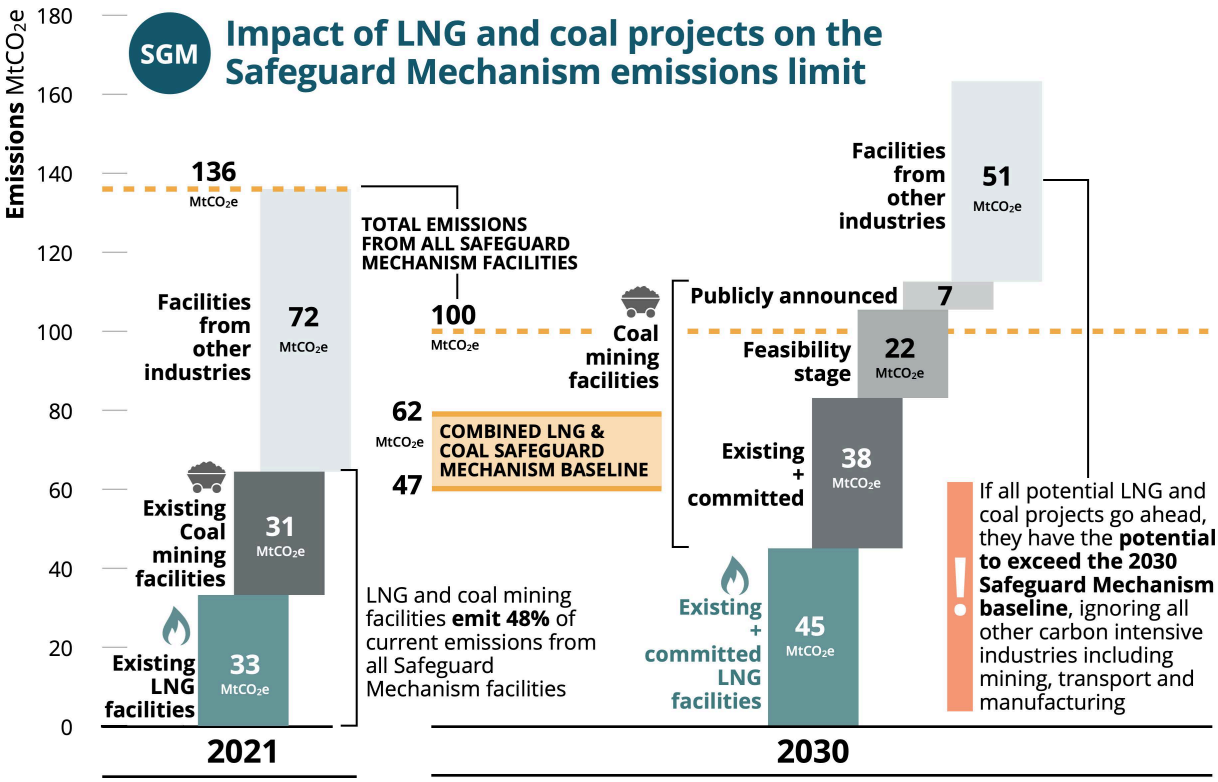

Figure 15: Impact of LNG and coal projects on the Safeguard Mechanism emissions limit.

Total emissions from other sectors than coal and LNG under the SGM were 72 $MtCO_2e$ in 2021. If they decline at the standard yearly rate of 4.9%, they would reach 51 $MtCO_2e$ in 2030.

However, the abatement task for these industries is likely to be magnified due to the scale of LNG and coal expansion plans and the likelihood of these facilities receiving baseline adjustment allowances.

Under a fixed limit of 100 $MtCO_2e$ in 2030 this would leave, in case no single coal projects or LNG expansions proceed, 39 $MtCO_2e$ for the rest of the SGM, implying an emission reduction from other sectors of at least 44% rather than 28%. In other words, under the current SGM proposals, the allowed share for LNG or coal will likely increase disproportionately, effectively transferring the **burden of additional emission reductions to maintain the 100 $MtCO_2e$ limit to other sectors**. These include so-called 'hard-to-abate' sectors like cement manufacturing, steelmaking, and chemical industries.

More stringent baselines theoretically incentivise fossil fuel producers to stay in line with the national emission reduction target. Letting fossil fuel facilities receive more lenient baselines could further undermine the SGM's efficiency and, consequently, domestic emissions reductions. With a public increasingly conscious of global warming, granting lax emission reduction targets to fossil fuel facilities would be harmful to the government's climate credibility.

The integration of new facilities is a critical aspect of the SGM reform design. In a situation where all entities under the mechanism must collectively reach 100 $MtCO_2e$ emissions by 2030, the addition of new entrants reduces the emission allowances of currently operating facilities. The government pledges to integrate new emitters with baselines derived from "best practices, adapted for an Australian context". These best practice values and their adjustment to the domestic environment are yet to be determined. They will be critical for enforcing the scheme's ability to reduce emissions from large facilities. It is yet unclear how LNG and coal developments will be integrated into the scheme. This matter is paramount for the LNG industry, including for projects such as Barossa.

As we have noted previously, even though prima facie there may be no new LNG-related facilities emissions from this sector are still expected to increase by about one-third, from 33 $MtCO_2e$ to about 45 $MtCO_2e$ in 2030. New entrants may predominantly be in the coal mining area and could add around 28 $MtCO_2e$ of new emissions to the sector by 2030.

LNG and coal emissions covered by the SGM accounted respectively for 7% and 6% of Australia's total GHG emissions in 2020 (Department of Climate Change 2022b). The Federal government aims at reducing the country's emissions by 43% below its 2005 levels. If this target is reached, LNG production would represent 13% of the country's emissions in 2030, and coal between 7% and 20%.

Significance of fugitive emissions

Fugitive emissions are the release of greenhouse gases that occur during the production, processing, transportation, and storage of fossil fuels. Fugitives have increased 23% since 2005 to reach 53 $MtCO_2e$ in 2020, with government projections indicating they are not expected to decrease before 2035 (Department of Climate Change 2022). The coal mining and LNG subsectors accounted for 79% of these fugitive emissions (Department of Climate Change 2022). This represents 10% of Australia's overall emissions in 2020, the equivalent of the carbon footprint of countries like Niger or Switzerland (Climate Watch 2022).

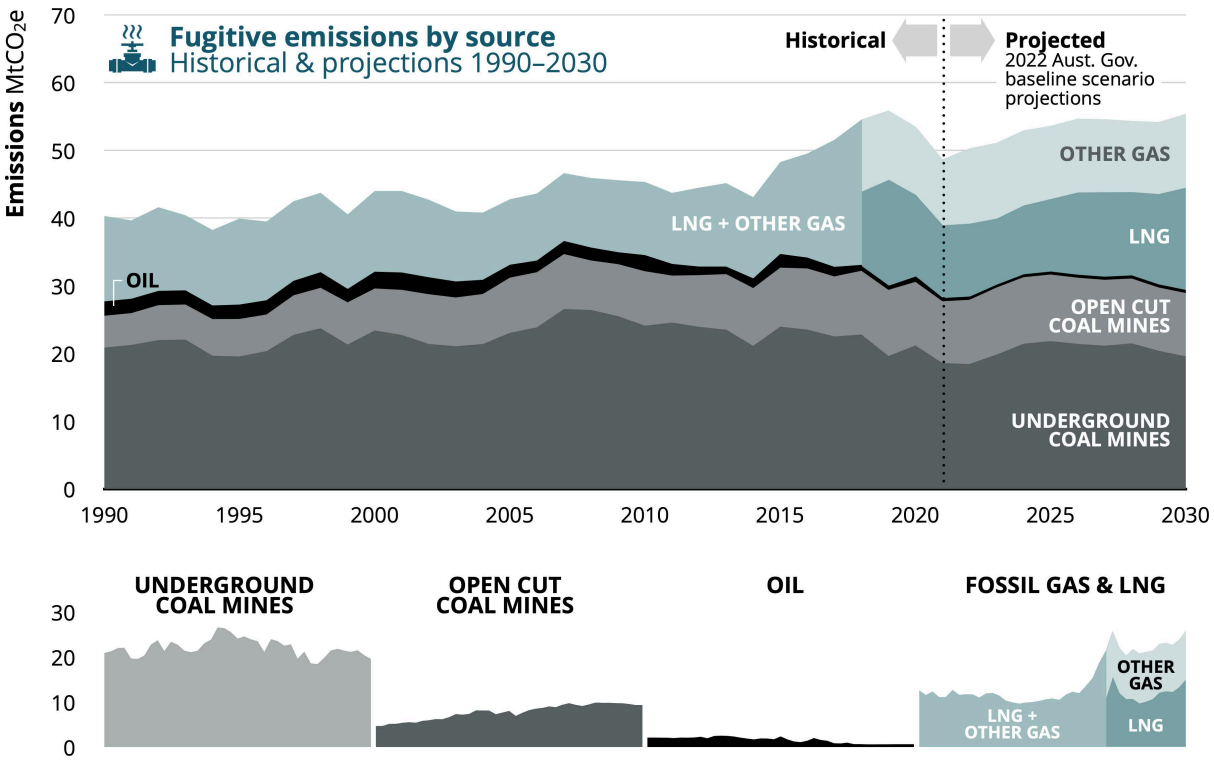

Figure 16: Fugitive emissions by source, historical and projections 1990-2030. (Department of Climate Change 2022)

Methane from coal mining

Fugitive emissions from coal mining are mainly methane.

In 2020, fugitive emissions from coal were 31 $MtCO_2e$, more than half of Australia's total fugitive greenhouse gas release (Department of Climate Change 2022). Despite shrinking in 2021 and 2022 due to floodings, fugitive emissions from the coal sector will increase past their previous level in the next two years, in part driven by the price demand due to the global energy crisis (Department of Climate Change 2022b). According to government projections, coal-related fugitive emissions will only start declining in 2028 thanks to mine closures.

Methane (CH_4) is released from coal seams at mine sites. Underground coal mines account for the majority of methane emissions. Methane leaks from both closed and operational coal mines. Methane is 25 times more potent in trapping heat compared to carbon dioxide (CO_2) in the atmosphere when compared on a 100-year time horizon. The IPCC finds that when compared over a 20-year time horizon, CH_4 is 82.5 times more potent than CO_2 (Forster et al. 2021). Methane has a shorter atmospheric lifespan (12 years) but has a much stronger warming effect while it is in the atmosphere. The short-term climate impact of Methane from Australia's coal mines is greater than the CO_2 emissions from the entire country's fleet of cars (Assan 2022).

It should be noted that the accuracy of methane emissions estimates has been repeatedly questioned in the last few years. Multiple observers note that methane emissions from the energy sector could be much higher than values currently reported based on satellite measurements (IEA 2022a; Sadavarte et al. 2021).

Fugitives from additional coal mine projects alone will add 42 $MtCO_2e$ of methane. Underground mine fugitives make up a large part, amounting to 35 $MtCO_2e$ (see table below). It is critical for coal mines to capture and utilise these methane leaks along with a coal phaseout plan.

Table 4 Methane (CH4) from coal mine fugitive emissions

	Mine type	CH_4 estimate* ($MtCO_2e$)
SGM projects 2020/21**	Underground	14
	Open cut	14
	Total	29
New Projects by 2030	Underground	35
	Open cut	8
	Total	42

Totals have been rounded.
**Assuming 95% of these fugitive emissions are CH_4.*
***Note that some current projects are scheduled to close by 2030.*

Gas reservoir CO_2 and carbon capture and storage

Fugitive emissions from Australia's 10 operational LNG projects have risen rapidly since 2015 to reach 12 $MtCO_2e$ in 2020 (Department of Climate Change 2022). According to the Department of Climate Change, this rapid increase has been catalysed by flaring activities in the first few years of operation and should decrease once projects mature. However, the largest source of fugitive emissions is reservoir CO_2 emissions, and these have increased rapidly. Overall, fugitives increased by about 180% between 2015 and 2020. Emissions related to flaring and venting increased by more than 50% between 2015 and 2020 (Government of Australia 2022).

According to government AGEIS data, CO_2 from gas venting and flaring represented 28% of Australia's total fugitives emissions in 2020 (DEE 2017) or 15 $MtCO_2e$. We estimate that in 2020, reservoir CO_2 emissions associated with LNG production were around 8.3-11.4 $MtCO_2e$, corresponding to an emissions intensity of 0.10-0.14 tCO_2 per tonne of LNG.

Australian gas reservoirs have historically had relatively low levels of reservoir CO_2. However, in the last few years, this has changed.

Looking to the future, new gas resources being developed such as Browse, Crux, and Barossa will have high levels of CO_2 significantly adding to the emission intensity of LNG production. After the maintenance of Darwin LNG facilities planned for 2023-2024, the launch of new large-scale LNG projects (Pluto LNG expansion in 2025, the connection of Crux field to the Prelude LNG project in 2027, and the connection of the Browse Basin to the North West Shelf LNG project in 2029) will cause an increase in fugitive emission related to LNG production (Department of Climate Change 2022b).

Considerable quantities of CO_2 are present in gas reservoirs, which need to be removed from extracted gas before use in LNG manufacturing and, to a significant extent, for domestic consumption.

Reservoir CO_2 must be taken out of gas, so in principle, it could be captured and stored underground instead of being vented.

Chevron's Gorgon Carbon Dioxide infrastructure, the only operating carbon, capture and storage (CCS) facility in Australia, is bound to a multi-year injection target with the state of Western Australia. Chevron committed to injecting at least 80% of the extracted reservoir CO_2. Since the first injection in 2019, three years after the first Gorgon LNG shipment, the CCS facility has consistently failed to meet this target, citing multiple technical difficulties. In 2020/21, Chevron injected 68.5% of the carbon extracted from the reservoir (Chevron 2021). For this analysis, it was assumed that the CCS facility functioned as intended in Chevron's commitment (that injection objectives were met every year starting 2021/22).

Santos has proposed deploying CCS infrastructure as part of the offshore Barossa development, which is targeted at backfilling the gas supply for the Darwin LNG plant (DLNG). At 18%, Barossa's gas CO_2 content is significantly higher than other exploited gas basins. The first portion of acid gas would be removed on the floating production storage and offloading unit (FPSO), before gas with around 6% CO_2 content is transferred to DLNG. In its NOPSEMA application submitted in 2017, ConocoPhillips estimated that the Barossa project will emit 5.4 Mtpa CO_2e for a production of 3.7 MPTA LNG.

According to the Institute for Energy Economics and Financial Analysis (IEEFA), Santos's initial plans for deploying CCS infrastructure at Barossa would have reduced emissions to 3.9 Mtpa, mainly by storing otherwise vented CO_2e from the FPSO (Robert 2022). However, in January 2022, Santos sent a new application to the Northern Territory Environment Protection Authority suggesting it has modified its plans (Robert 2022). Considering these changes, which include the building and operation of a duplicate pipeline from the gas field to the Darwin facility, the IEEFA estimates that the deployment of CCS infrastructure would not decrease overall emissions from Barossa,

as emissions reductions would be in part replaced by emissions from additional combustion.

Notwithstanding these issues, and assuming that capture of reservoir CO_2 remains technically feasible, we estimate around 11.5-15.5 $MtCO_2e$ per year could be emitted in total by 2030. With an overall 80% capture rate, as ultimately expected at Gorgon then abatement of 9 to 12 $MtCO_2e$ per year could be achieved, adding up to about 30-40 $MtCO_2e$ cumulatively. If achieved, this would reduce total LNG-related annual emissions from 45 $MtCO_2e$ per year in 2030 to 33-36 $MtCO_2e$ per year.

Total demand for offsets/ACCUs

In Australia, carbon offsets generated under the Australian Government-regulated scheme are called Australian Carbon Credit Units (ACCUs), a majority of which are created by land sector projects like forest regeneration and avoided deforestation. Until now, facilities under the SGM have been permitted to generate ACCUs by undertaking emissions reduction activities, but under proposed reforms to the SGM, this will no longer be the case (Department of Climate Change 2023).

Instead, it is proposed facilities will be allowed to purchase an unlimited amount of ACCUs to achieve their emissions baselines, if the proposed reforms proceed in their current state.

At least in relation to the LNG and coal mining sectors, where there is little sign of any real abatement efforts actual or planned, this is likely to cause a steep increase in demand for ACCUs, leading to the establishment of a slew of new projects, many of which will be in the land sector where questions of offset integrity are most pressing.

A recent analysis by Climate Analytics outlines the many acute problems with land sector offsets, including those relating to the Australian context (Wilson, Hare, and Grant 2023). Land sector offsets are fundamentally less effective compared to a direct emissions reduction at source due to the impermanence of the carbon storage, while several land sector methodologies have failed to ensure additionality of emissions reductions, or to achieve emissions reductions at all.

This has led to the creation of, by one estimate by independent experts, around 65 million “high risk, or low integrity” ACCUs, or roughly 65 $MtCO_2e$ of purported abatement that is unlikely to be real and/or additional (Macintosh et al. 2023). These credits are still available for purchase, and many will likely be bought by SGM facilities to comply with their declining emissions baselines. Worse still, projects shown to have methodological flaws will continue to produce ACCUs for sale.

The Australian Government’s emissions projections which outline total GHG emissions for SGM-covered facilities show compliance with the mandated emissions reductions, reaching 100 $MtCO_2e$ in 2030.

A modest use of ACCUs is projected, totalling 9 $MtCO_2e$ of abatement in 2030, or 20% of total required abatement in that year (Department of Climate Change 2022b). A conservative assumption that 20% of the total projected cumulative abatement task is met with offsets would mean the likely purchase of 41 million ACCUs, or 41 $MtCO_2e$ of cumulative abatement to 2030.

This figure is dwarfed by the total cumulative abatement required for LNG and coal producers to meet their respective emissions reduction requirements.

For LNG producers, we find the cumulative abatement gap between likely future emissions to 2030 and likely emissions baselines, trade-exposed adjusted and industry average, of between 49-75 $MtCO_2e$ respectively (see Figure 15).

For coal, the respective numbers are 24-160 $MtCO_2e$ under a trade-exposed adjusted baseline, and 46-184 $MtCO_2e$ under an industry average baseline.[1] With limited mitigation options, a large share of this discrepancy is likely to be addressed by purchasing offsets.

CCS, the one key technology touted as a possible solution for reducing emissions from LNG production, has not yet been proven in Australia, with Chevron's CCS project experiencing major technical problems. To date, Chevron has been required to purchase millions of carbon offsets to make up for its CCS failings, a large majority of which were sourced outside Australia.

Capturing and storing reservoir CO_2 emissions would be an option however the industry has claimed it is too expensive. Nevertheless, this could have the potential to close the abatement gap by 30 to 40 $MtCO_2e$. The ability to purchase an unlimited number of cheap offsets completely removes the incentive for these companies to invest the resources necessary to scale up CCS in Australia.

Under a worst-case scenario, the total cumulative abatement gap could be as high as 259 $MtCO_2e$, greater than the entire projected accumulative abatement required under the whole SGM until 2030 of 205 $MtCO_2e$.

At a minimum, we calculate this abatement gap for coal and LNG to be 73 $MtCO_2e$, almost double our estimate of total cumulative use of ACCUs by SGM facilities under government projections, of 41 $MtCO_2e$.

Under either scenario, or anywhere in between, this represents an enormous source of demand for ACCUs, incentivising a wholesale increase in offsets generated using suspect methods that do not represent genuine emissions reductions.

[1] Ranges for cumulative coal emissions above both trade-exposed adjusted and industry average baselines reflect the uncertainty as to how many planned projects will actually eventuate.

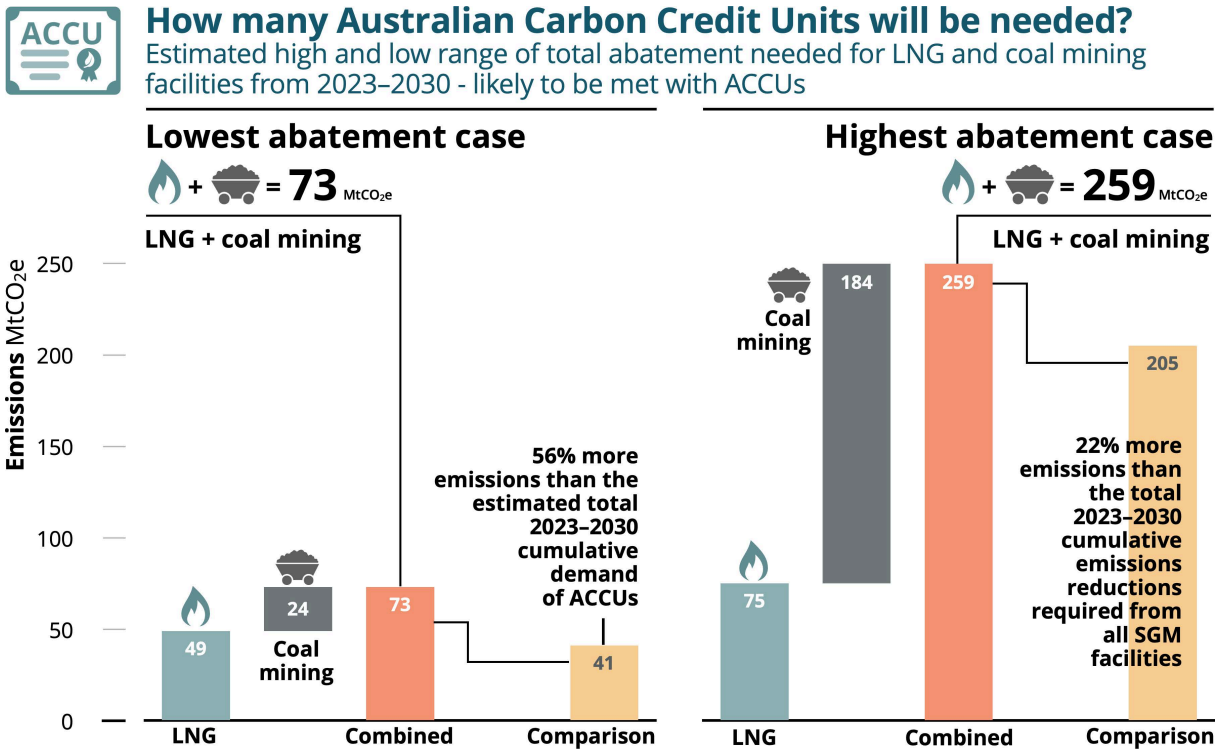

Figure 17: Range of potential offsets for LNG and coal mining to 2030.

Land area needed to meet ACCUs

The makeup of ACCUs to date is split into projects from the following categories: vegetation, landfill and waste, savanna burning, energy efficiency, agriculture, industrial fugitives, and transport (see Figure 16)

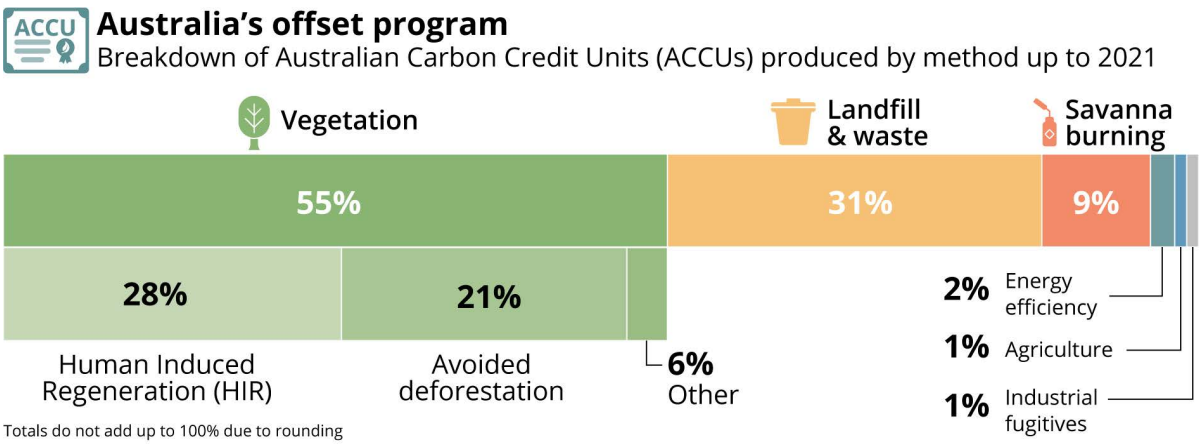

Figure 18: Existing ACCU breakdown by method as of 2021.

As one of the largest sources of ACCUs to date, the human induced regeneration (HIR) method has a considerable impact on land use in Australia. The modelled potential land usable in HIR projects is around 28 million hectares, almost a fifth the of size of

Australia's total forested land, and roughly the size of Victoria and Tasmania combined (Roxburgh et al. 2020).

Using all of this land for HIR projects is projected to enable on average, 47 $MtCO_2e$ of annual abatement after 25 years of forest regeneration. This theoretical level of annual abatement is only 50% more than that necessary from just the LNG and coal industries under our worst-case scenario calculation.

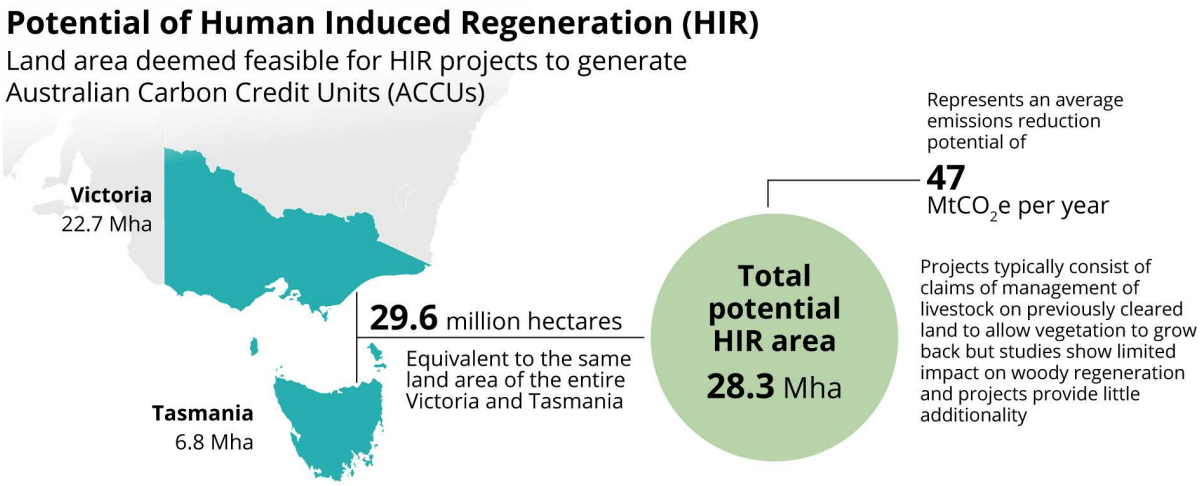

Figure 19: Extent of potential Australian land area utilised by HIR projects. Source: Own adaptation of data from Roxburgh et al 2020.

The equivalent area for potential land use by afforestation and reforestation projects in Australia is 2.0-3.1 million hectares. This is roughly the size of Melbourne and Sydney combined and would require the conversion of viable agricultural land.

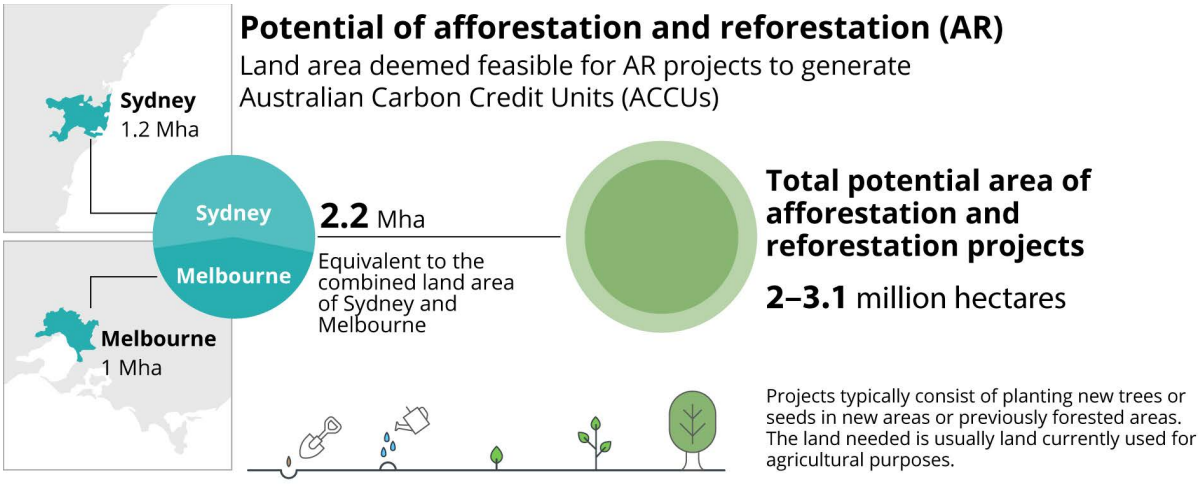

Figure 20: Land area in Australia deemed feasible for afforestation and reforestation projects to generate ACCUs.Source: Own adaptation of data from Roxburgh et al 2020.

While the commitment of large swathes of additional land to reforestation or forest regeneration is notionally a desirable outcome, it matters greatly what the actual outcomes of these projects are.

Grave concerns have been articulated by independent experts that a large portion of HIR projects have limited impact on the level of forest regeneration and therefore emissions reductions additional to those that would have occurred anyway, meaning previously productive land would be confined to meritless or low merit activities (Macintosh et al. 2023).

With regards to reforestation projects, those that produce non-native and/or monoculture forest stands risk failing to achieve ecosystem restoration and biodiversity improvements. A massive uptick in ACCU demand caused by SGM LNG and coal facilities could increase the risk of such low-quality projects being funded to meet this demand.

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