



2 October 2025

To: NSW Environment Protection Authority

Re: Climate Change Licensee Requirements and Greenhouse Gas Mitigation Guide for NSW Coal Mines

Thank you for the opportunity for the Institute for Energy Economics and Financial Analysis (IEEFA) to provide input on the NSW Environment Protection Authority (EPA)'s consultation on its proposed Climate Change Licensee Requirements and Greenhouse Gas Mitigation Guide for NSW Coal Mines.

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

IEEFA thanks the NSW EPA for the significant work in developing the draft guidelines. IEEFA commends the EPA for proposing to take a more active approach to greenhouse gas (GHG) emission reporting and monitoring, instead of relying solely on the federal Safeguard Mechanism and Clean Energy Regulator reporting frameworks. IEEFA also supports the NSW EPA proposal to mandate methane abatement actions at underground coal mines in NSW.

However, the proposed Climate Change Licensee Requirements and Greenhouse Gas Mitigation Guide for NSW Coal Mines still present risks to NSW meeting its state-based emissions reduction targets. Most importantly, the proposed guidelines currently do not propose mandating any methane abatement action at open-cut coal mines in NSW, which could leave the majority of coal mine methane emissions unabated.

IEEFA proposes that the following points be incorporated into the Greenhouse Gas Mitigation Guide for NSW Coal Mines:

- Methane abatement action at open-cut coal mines should be mandated, in line with underground mines.
- Focusing only on underground coal mine methane ignores a potentially greater source of fugitive methane emissions in the state.
- The proposal to make regenerative thermal oxidation (RTO) technology mandatory is supported. The EPA should be open to factors to mitigate delays to implementation and to tighten up opt-out provisions.

Kind regards

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Methane abatement at open-cut coal mines should be mandated, in line with underground mines

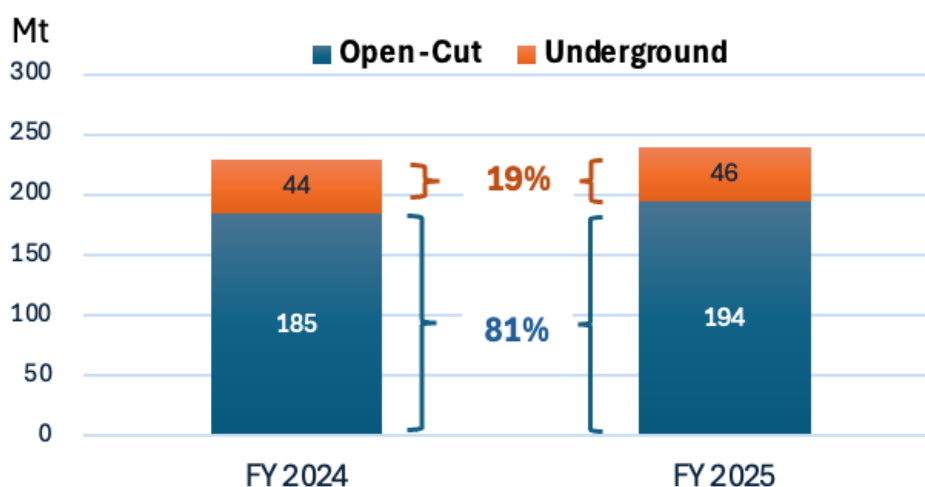
IEEFA recommends further requirements be added to the guidelines to incentivise methane abatement and decarbonisation at open-cut coal mines in addition to the requirements proposed at underground coal mines in the state. Given the prevalence of open-cut methods in NSW coal mining, methane emissions from both underground and open-cut mines will require regulation to achieve meaningful reductions.

For coal mines, the NSW EPA has focused primarily on underground coal mine methane abatement opportunities, but it could also add requirements for open-cut coal mines to either begin pre-drainage trials or provide detailed evidence as to why they cannot conduct pre-drainage at their mine site. Recent examples from QLD suggest that methane abatement at open-cut coal mines is feasible, and under certain conditions can be financially viable. For instance, [Coronado Resources](#) commissioned a methane pre-drainage trial system at its Curragh mine, using the methane to displace some diesel used in its truck fleet. Additionally, [Stanmore Resources](#) received government funding to capture methane for at least 15 years to power a new 20-megawatt gas-fired power station, to be completed by 2027. The power station is expected to entirely offset Stanmore's South Walker Creek mine's electricity requirements.

Focusing only on underground coal mine methane ignores a potentially greater source of fugitive methane emissions in NSW.

Open-cut coal mine production accounts for 81% of coal production in NSW (Figure 1). By only including mandatory abatement actions for underground coal mines, the proposed GHG mitigation guidelines are ignoring most of the state's coal production and potentially a larger source of coal mine methane emissions.

Figure 1: NSW run-of-mine (ROM) coal mine production in FY2024–FY2025



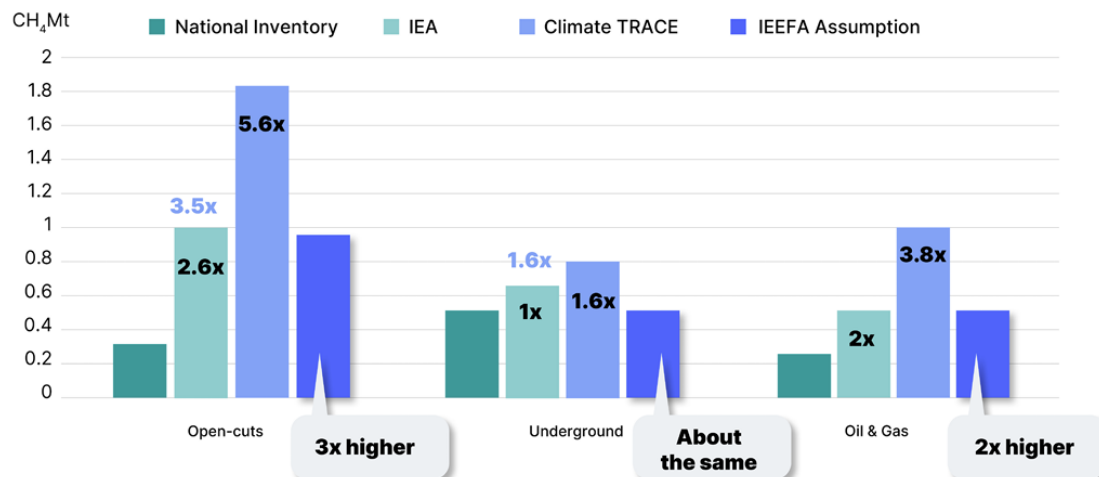
Sources: NSW Coal Services, [NSW Coal Industry: Production & Stock Report, July 2025](#); IEEFA.
Note: Mt = millions of tonnes.



The assumption that underground coal mines contain more methane than open-cut coal mines may be incorrect.

Although reported methane emissions are higher in underground coal mines than open-cut coal mines, there is a growing body of evidence that reported methane estimates from open-cut mines in Australia could be significantly underestimated. The Australian government has [calculated](#) the uncertainty in methane emissions reporting by open-cut mines is at least 30%. Additionally, [analysis](#) by the Superpower Institute suggests methane emissions from the fossil fuel sector could be twice as high as reported, and [data](#) from the International Energy Agency (IEA) suggests open-cut coal mine emissions could be three times higher on average than reported.

Figure 2: Estimated methane (CH₄) emissions underreporting by Australian coal, oil and gas



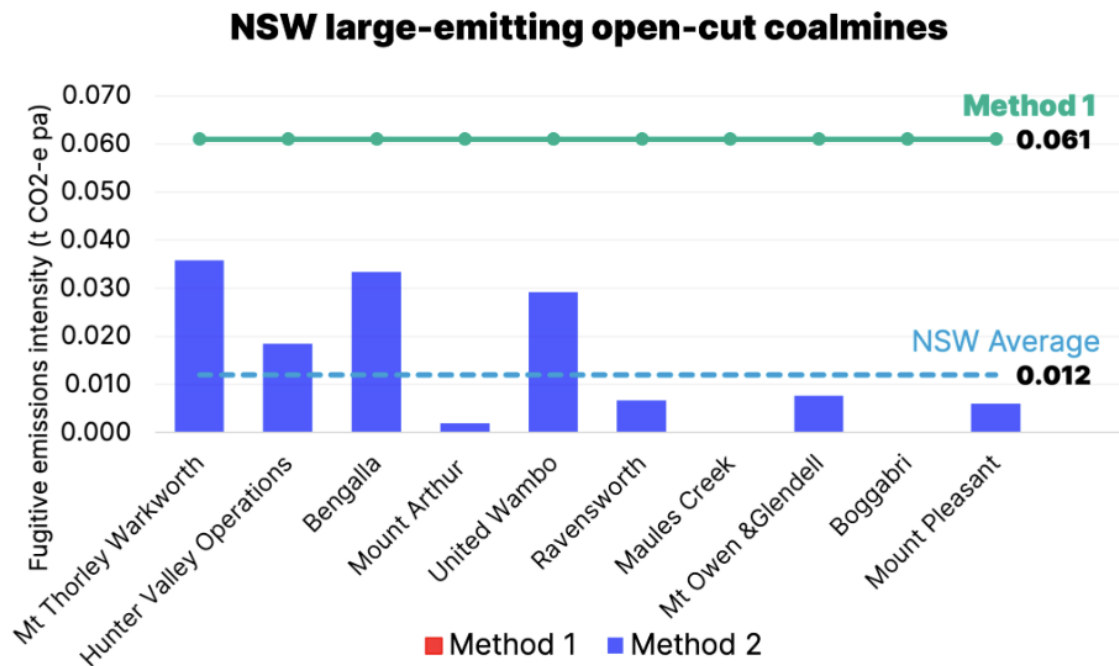
Sources: Department of Climate Change, Energy, the Environment and Water (DCCEEW); IEA; [Climate TRACE](#); IEEFA.

Note: The IEA does not report on underground and open-cut mine methane estimates separately; IEEFA considered a range of underreporting factors based on underground emissions varying between reported levels and Climate TRACE levels.

Additionally, all open-cut coal mines in NSW recently moved from using Method 1 to Method 2 under the National Greenhouse and Energy Reporting (NGER) Scheme to estimate methane emissions from coal mining. There is potential that total Scope 1 emissions would have decreased during this period due to decreased production, mining less gassy seams or decreasing carbon dioxide (CO₂) emissions. However, when examining data from other large NSW open-cut coal mines, the reported methane emissions per unit of coal produced were 80% lower under Method 2 estimations compared with Method 1 default factors, based on the FY2024 [Safeguard Mechanism data](#). This means the decrease in reported emissions would not be driven by a decrease in production.



Figure 3: Method 2 actual reported methane emissions intensity vs Method 1 standards



Source: IEEFA, [Australia's coalmine methane mirage: the urgent need for accurate emissions reporting](#), April 2025.

Note: tCO₂-e = tonne of carbon dioxide-equivalent.

A Climate Change Authority [review](#) of the Methods in the NGER Scheme recommended, “as a matter of urgency, review Method 2 ... with respect to sampling requirements and standards”. It found there were significant discrepancies between reported emissions and emissions estimated using satellite data.

As far back as 2019, [research](#) by the University of Wollongong found the Method 2 approach to determining “low-gas zones” was flawed. This is due to the standards containing an artificially high threshold for gas detection, and an associated low amount of gas assumed for the low-gas zone, effectively underreporting gas considerably. This is most pronounced when high levels of methane are found in the gas (due to gas density differences). The study recommended lowering the threshold gas factor used in Method 2 by an order of magnitude.

Glencore previously [stated that](#) “pre-drainage is not currently economically viable for a multi-seam open-cut mining operation such as HVO”. It later revised its position [in response to](#) submissions on the HVO Continuation Project environmental impact statement, committing to undertake a pre-drainage trial and to consider pre-drainage later in the mine’s life.

There are examples of other miners trialling methane drainage at open-cut mines, and multiple research studies have found that it can present a net economic benefit. A study by the University of [Queensland’s Gas and Energy Transition Research Centre](#) found methane abatement was economically viable in a range of scenarios, including: (1) flaring the gas; (2) selling it; (3) generating electricity; and (4) displacing diesel in mining operations.



However, even if more open-cut coal mines conduct pre-drainage, [a range of studies show that](#) only 50-80% of methane can be captured and abated via this method, under best-case scenarios. This means the remaining options for open-cut miners to achieve net zero CO₂-e emissions by 2050 would be to purchase carbon credits or reduce coal production.

Q2.1 If surface mines were required to pre-drain gassy seams and destroy methane before mining commences, what factors would impact feasibility?

Several technical and commercial factors affect the feasibility of methane abatement in coal mining. This applies equally at open-cut and underground coal mines.

NSW has announced funding of more than \$300 million to progress heavy industry decarbonisation, including coal mining. However, with Australian coal miners reporting lower profit margins and taking decisions to reduce or defer capital spending in 2025, many decarbonisation projects are likely to fail to attract investment in the near term.

Some 95% of NSW's coal mining emissions are covered by the federal Safeguard Mechanism. The Safeguard Mechanism is expected to provide an additional financial incentive for coal miners to abate emissions in the latter part of the decade. Most of the burden of the emissions reduction requirements is expected to fall to the underground miners, and many coal mine facilities have increased their emissions baselines under the Safeguard Mechanism, meaning no structural reduction is necessary. In addition, the unlimited use of carbon offsets to meet emissions baseline requirements compromises real emissions abatement, and undermines NSW's emissions reduction targets. Offsets sourced from other states do little for NSW's emissions reduction capability.

The NSW EPA's proposal to reduce emissions from underground coal mines

The proposal to make regenerative thermal oxidation (RTO) technology mandatory could be implemented sooner than 2030.

The NSW EPA proposal highlights that RTO technology for ventilation air methane (VAM) abatement at underground coal mines is considered mature and commercially available, but that no underground mines in NSW are using this technology. IEEFA welcomes the proposal by the EPA to require VAM abatement on all applicable underground mine shafts by July 2030, and to detect and manage methane leaks from underground coal mines by July 2027 – noting that the requirement to implement VAM abatement is dependent on the results of VAM RTO trials in NSW and Queensland in 2028. Managing VAM emissions from underground mines is an important step in reducing methane emissions from these mine types, and RTO is a proven technology capable of reducing underground coal mine Scope 1 emissions while new, more effective forms of VAM abatement complete their trial processes and become commercially ready to deploy at scale.



The EPA proposal for VAM abatement being subject to trials and early consideration by the EPA could be problematic. Mandating RTO to be subject to these trials having been completed, reviewed, and issues resolved before mandatory implementation could challenge timeframes. There is a [critical skills shortage](#), which is particularly acute in underground mining. Miners need to plan for the infrastructure within mine designs and surface infrastructure. Regulators will need expertise and capacity to evaluate the plans for implementation. Individual mine submissions and objections could delay decision-making across the 14 underground mines operating in NSW. Such factors need to be mitigated to meet the 2030 implementation deadline. Consequences for non-compliance need to be considered.

Miners should be required to progress some form of abatement. No action should not be an option.

Given the potential for relaxation of VAM requirements, as outlined above, abatement contingencies should be prepared. For example, the EPA proposed VAM abatement applies only if the mine is to operate beyond 2032. This raises questions about what abatement conditions – if any – would be required for a mine that is currently permitted to cease operations prior to 2032. Also the EPA proposal that the Western coalfields be exempt should be rejected. Claims that these seams do in fact have a lower methane and gas content cannot be verified without proper measurement.

Potential avenues for opting out of abatement are many and require an alternative strategy, in case the VAM provisions are weakened. Such strategies should consider enhanced gas drainage or mine sealing practices. There are multiple opportunities to capture methane:

- **Pre-drainage:** Gas is extracted from the coal seam and surrounding strata before mining begins. The gas residing in the coal seam needs to be pre-drained down to safe working levels.
- **Ongoing ventilation:** VAM systems move fresh air into the mine and flush out methane emissions to maintain safe working conditions.
- **Post mine sealing and drainage:** During mining gas drainage works continue to lower gas content in the longwall goaf and surrounds.

The proposed EPA amendments for gas drainage with flaring or utilisation would have them in place by July 2027; these should be expanded to include provision for additional abatement requirements. For example, if for any reason VAM abatement is not mandated, the regulator would establish stricter pre-drainage standards. These would apply for emissions reasons and be in addition to the current operational safety considerations. For example, they might require the gas pre-drainage threshold, to be reached prior to mining, to be lowered by, for example, a few cubic metres per tonne, as determined by the regulator. Such requirements could be done in conjunction with improved mine sealing requirements. It would effectively mandate a reduction in gas being released from mining, in the absence of VAM abatement. The onus for demonstrating active gross emissions reduction, as a pre-condition to mining, should fall squarely onto the mine.

The EPA's proposed requirement for continuous VAM monitoring at underground mines by 2026 should assist information transparency. Additional data monitoring should be considered such as



reporting of post-drainage methane concentration. It should ensure comprehensive monitoring, reporting and verification processes and data distribution methods are established to verify facility level measurement.

The NSW EPA should maintain a balanced approach to diesel fuel transition

Q3.1 Should the EPA progress a regulatory requirement for 2.5% of fuel used at NSW coal mines to be a low carbon alternative to fossil diesel by 2027?

Often the largest source of GHG emissions at open-cut coal mines is diesel combustion, typically resulting from the operation of haul trucks. In NSW approximately 27% of mining Scope 1 emissions comes from diesel combustion.

A [report](#) by the Clean Energy Finance Corporation has found that due to more rapid electrification in other sectors, by 2050 the aviation, heavy freight and mining sectors will consume 80% of Australia's liquid fuel demand.

The NSW EPA proposal includes a tiered phase in approach for fossil diesel replacement: by July 2030, 5% of fuel used is a low-carbon alternative to fossil diesel; this increases to 10% by July 2035, and higher rates beyond 2040. There are a number of issues for consideration that will determine whether the EPA will impose a regulatory requirement for 2.5% blend of fuel by 2027.

Firstly, on regulation and enforcement, the EPA does not outline how it proposes to monitor and control the introduction of renewable diesel blends at mine sites. Conditions will only be as effective as the EPA's ability to enforce them.

Secondly, the impact on the viability of low carbon liquid-fuel (LCLF) manufacturing in Australia must be considered. The establishment of offtake partners such as the mines for the fuel will be an important aspect for early development of the fledgling industry. In this sense, a requirement as proposed would provide additional surety for the business case of these LCLF manufacturers.

Finally, on technology choice, the EPA proposal is silent on electrification or other diesel decarbonisation pathways. The Department of Industry, Science and Resources (DISR) [2025 Resources Sector Plan](#) for reducing diesel emissions includes two levers: electrification, and low-carbon fuels. While low-carbon fuels represent a more realistic short-term 'drop-in' solution in small quantities, the EPA should be careful to remain technology-agnostic through its guidance and regulations.

Q3.2 Can coal mines transition to low or zero emissions large mining machinery and low carbon alternatives to fossil diesel sooner?

Miners disclose their decarbonisation strategies and spending plans in their annual reports or sustainability reports.



BHP noted in its [2025 Annual Report](#) that its capital spend on operational decarbonisation has been delayed. It had previously planned to spend \$500 million up to 2030 – across all its business lines. Its updated assessment is that “the introduction of diesel displacement technology into our operations accounted for most of our previously allocated operational decarbonisation expenditure in the decade to FY2030 and this expenditure will now be delayed into the 2030s.” This was because “the pace of development of some decarbonisation technology has slowed, particularly in the displacement of diesel used for materials movement”.

Some miners may consider these investments as discretionary and subordinate to the capital return needs of shareholders. Companies operate on the principle of acting in the best interest of the company and its shareholders. Emissions management is an area where conflict could arise between capital allocation decisions for the company and environmental benefits. The impact of trends in company profitability and surplus cashflow can impact the availability of capital.

Some miners have recently reported declining profitability, which might lead to a slowdown of abatement activity or a rescaling of activity within the broader context of the company’s capital rationing efforts.

Q3.3 What are the barriers and opportunities?

Miners such as Rio Tinto and Glencore have performed trials of operating on biodiesel blends in their heavy mining equipment. The HVO Continuation project documents report that Glencore’s coal operations have previously used biofuels in mining equipment (specifically B20, which is a diesel fuel containing 20% biofuel). However, operations do not currently use this fuel due to both cost and availability. Barriers to the use of sustainable fuels include cost, limited availability, and land-use issues if it were to displace food-growing activities.

The opportunities lie in the commercial funding made available through the federal government’s \$1.1 billion [low-carbon fuels initiative](#).

Policies for decarbonisation of diesel in mining should be technology-agnostic. Several decarbonisation pathways are emerging, including biofuels, renewable diesel, electrification, hybrids, trolley assist, compressed natural gas and hydrogen. The [DISR 2025 Resources Sector Plan](#) includes an important pathway of “demonstration and commercialisation of electrified haulage and equipment”. It is important that clean-fuels initiatives do not act as a barrier to delay or deter full decarbonisation.

The single largest barrier to decarbonisation of diesel fuel is cost, which is currently distorted by the federal Fuel Tax Credit Scheme. The diesel fuel rebate scheme in the Australian tax system subsidises the continued use of fossil diesel at coal mines by providing [currently 51.6 cents/litre](#). While this scheme is used by other industries in the country, existing analysis from [Climate Energy Finance](#) found that mining receives the majority of this subsidy at \$57.5 billion to date. This is 3.6 times more than agriculture, and 2.4 times more than transport. Australian mining company [Fortescue](#) has stated: “Australia’s diesel rebate encourages major mining companies to keep burning fossil fuels by allowing them to claim back millions in tax credits. Every dollar they save comes at a cost to our environment, economy, and public health”. For the coal sector, the



Resources Sector Plan states: “Treasury’s Baseline Scenario indicates that in 2050, fuel combustion emissions in the sector will reduce to around 20% of what they are in 2025.”

Additional considerations and feedback on the Proposed Climate Change Licensee Requirements

Overall, the EPA proposal indicates that NSW no longer wants to take a backseat to greenhouse gas emission reporting and monitoring. By requiring facilities to provide data directly to the NSW EPA, this avoids NSW relying solely on federal government data and reporting to monitor its progress on its emissions reduction targets.

The requirement to provide a breakdown of these emissions by greenhouse gas type and activity as appropriate, should ensure it requires a breakdown of methane and carbon dioxide emissions from coal mine facilities and any other facilities operating in industries with known methane emission risks. Additionally, for coal mine facilities a schedule of volumes should be provided and should include details of how these emissions were estimated.

The current proposed Climate Change Licensee Requirements and Greenhouse Gas Mitigation Guide for NSW Coal Mines still present risks to NSW meeting its state-based emissions reduction targets.

These measures alone will not guarantee NSW can meet its state-based emissions reduction targets, but it is a step in the right direction and will help NSW take better ownership over the emissions in the state without relying solely on Safeguard Mechanism data shared and reported by the Clean Energy Regulator. Requiring this data from licensees who emit over 25,000 tonnes of CO₂-e also means the state will be able to collect more data than the NSW-listed facilities under the federal Safeguard Mechanism, which only includes facilities emitting over 100,000 tonnes of CO₂-e in a given year. Effectively this data collection should include all coal mines licensed in NSW. This will generate a more comprehensive picture of the industries and facilities to engage with in NSW and will help the state to understand the primary sources of methane and carbon dioxide emissions from different industries. However, the improvements in state-based emissions reporting must also be matched with the implementation of proven and effective emissions abatement strategies at these facilities if NSW wishes to meet its state-based emissions reduction targets.

Q7.1 Do you have any suggestions to improve the robustness and transparency of the pre-feasibility assessment process, and to reduce compliance costs for licensees?

As the Environmental Defenders Office (EDO) points out in [Improving Regulation of Coal Mine Methane in NSW](#), regulators imposing conditions that are to be implemented subject to being “reasonable and feasible” leave much room open for subjective interpretation by the proponent. This can lead to indefinite delays to implementation of mitigation measures.



Relying on miners to assert the reasonableness or feasibility of approaches to decarbonising their operations is problematic. There is no requirement for miners and their consultants' technical feasibility reports to be independently validated, which could lead to lack of transparency. If "reasonableness" tests are to continue, consideration should be given to miners providing funding to EPA to undertake studies rather than miners funding and directing these studies.

In FY2024, when some facilities exceeded the 30% limit on their use of Australian Carbon Credit Units (ACCUs) under the Safeguard Mechanism, they were required to publicly disclose the reasons why they were not able to achieve abatement requirements. Most responded that there was a lack of technical and commercial readiness. However, these assertions by companies are not challenged and do not require evidence to be submitted.

One issue with the disclosure of feasibility assessments concerns the disclosure of confidential or proprietary information or financially sensitive information. Miners are careful to consider what level of information disclosure is available in the public domain. This issue can cloud transparency and third-party verification of feasibility claims.

Q7.2 Should the exemptions process outline the circumstances in which an exemption does not need to be sought on specific technical feasibility grounds?

Any standard that allows for an exemption would potentially weaken the framework. Considering the information asymmetry discussed above, an independent balanced review of exemptions is likely to lack all of the facts necessary to make an informed judgement.

Perhaps an alternative approach needs to be taken for assurance, to safeguard against exemptions becoming the norm. Rather than attempting to overrule a miner on the reasonableness or the feasibility of conducting a project on its mine, a financial assurance mechanism could be introduced.

Using a rehabilitation financial assurance model as a framework, where funds are quarantined for rehab purposes, mining companies must provide financial assurance equal to 100% of estimated rehabilitation costs before operations commence. It could be reserved in cash or as a bank guarantee, for such circumstances as when technical feasibility can be achieved.

Specific mitigation actions would be tied to strategies and capex plans. These would normally be detailed in the comprehensive sustainability reporting but are not present in the current reporting or in the climate change mitigation and adaptation plans (CCMAP) documents envisaged by the EPA. Documentation including ascribing a capital investment estimate to a mitigation strategy would be the first step in this process. The value of financial assurance to be held for the EPA could be periodically modified as cost estimation changes. The annual or periodic updating of sustainability reports and CCMAPs respectively would provide an opportunity to update capital spending estimates. Financial provisioning would be based around the capex plans, perhaps with funds released as abatement milestones are achieved. It would follow a similar process to progressive rehabilitation for miners.



Q7.3 Any exemptions issued by the EPA would be made public. Should any of the information in the pre-feasibility assessment be made public?

If the EPA's role is to merely make and enforce the framework including case for exemptions, then little is to be gained from making the assessment public. If the EPA or other organisations are interested to develop new technologies, share best practices and foster collaboration, then information-sharing could form a large part of that arrangement.

The DISR's 2025 Resources Sector Plan sees a role for industry-led innovation: "Industry-led initiatives, often in collaboration with research institutions look to innovate in emissions abatement technologies (ACARP 2025). These have reached various levels of technology readiness, and it is imperative that private investment continues to support these innovations to scale up and commercialise." It is important that these programs and funding for these programs remain with independent bodies. Fossil fuel-sponsored or -led programs can lead to inaction on decarbonisation.

There should be some recognition of the fact that much of the abatement technology is at an early stage of deployment maturity. Reward mechanisms should favour innovation, collaboration and information-sharing across trials and demonstration activities. This is needed to maximise the long-term abatement potential for the industry.

Q7.4 Should there be an avenue for public input into the exemptions process and, if so, how? Is the publication of CCMAPs and progress against CCMAPs sufficient to provide transparency?

Miners have approached the development of annual sustainability reports with varying success. For example, [IEEFA found](#) that sustainability reporting for miners contained generic statements about future decarbonisation considerations but lacked detail on concrete near-term actions, despite some reports being lengthy documents.

IEEFA supports the EPA's proposed requirement for miners to produce and publish CCMAPs. However consideration need be given to the potential for duplication among other sustainability reporting documents required of coal mining companies, such as:

- Annual Sustainability Reports.
- Climate Change Action Plans.
- Air Quality and Greenhouse Gas Management Plans.
- AASB S2 Climate-related Disclosures.

To date, such reporting has been ineffectual in providing transparency around miners' strategies for achieving emission reduction targets and requirements. This reflects our earlier recommendation on proposal for disclosure of decarbonisation capital spending plans and financial assurance requirements.



About IEEFA

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

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