Guidance note – Assessment of coal production costs and fair margin

Under the Coal Market Price Emergency (Directions) Notice 2023; *Energy and Utilities Administration Act (NSW) 1987*

July 2023

AUSTRALIAN ENERGY REGULATOR

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1 Introduction

This guidance note outlines the Australian Energy Regulator's (AER) expectations for the information a Coal Supplier is to provide to the NSW Minister for Energy (Minister) when applying for a higher price cap for thermal coal. It also details our assessment approach for assessing these applications and advising the Minister on whether to alter the price cap.

Attachment 1 of this guidance note provides the form which Coal Suppliers must use when submitting their application to the Minister. The form sets out the components we expect to make up an individual coal mine's production costs, and the level of detail we require in making our assessment.

Our approach to estimating the cost of domestically supplied coal will necessarily involve elements of judgement. We will not be performing a detailed investigation into the cost build-up. We are estimating the production costs and fair margin for domestically supplied coal, rather than the lost opportunity to supply coal on international markets. This process is not intended to compensate for what a Coal Supplier would have received absent a price cap on coal. What this guidance note does do is to provide a general framework for how we would estimate a cost of production plus a fair margin for domestically supplied coal at a particular calorific content and for a particular mine that may be more appropriate than the $125/tonne for 5,500 kcal/kg coal (or equivalent) as set out in the *Coal Market Price Emergency (Directions for Coal Mines) Notice 2023*.[1]

Our assessment approach for production costs will be focused on the circumstances of the relevant coal mine. This contrasts with our fair margin approach, which is based on the application of a consistent fair margin across the sector. These two are intended to be complementary, in that all relevant cost categories are either directly incorporated in the production cost build up or included in the benchmark fair margin.

Once our assessment of the application is complete, we will advise the Minister of our findings, which may include a recommendation to the Minister to:

- apply the Coal Supplier's proposed price cap
- apply an alternative price cap as advised by us, or
- continue to apply the $125/tonne price cap.

The information in this guidance note is informed by feedback we received from stakeholders, including Coal Suppliers.

Our approach to developing this guidance note has been guided by regulatory best practice, namely:

- Communication and consultation
  - We have worked closely with affected Coal Suppliers to understand the make-up of costs for NSW coal mines.

[1] Coal Market Price Emergency (Directions for Coal Mines) Notice 2023 made pursuant to Energy and Utilities Administration Act (NSW) 1987, 15 February 2023.

  - We have kept the Coal Suppliers and other relevant stakeholders informed of the progress of our proposed assessment approach in a timely manner.
  - We have undertaken targeted consultation through both bilateral meetings and an online public briefing to receive feedback to assist us in developing this guidance note.
- Flexible
  - Whilst we recognise that there are many areas of commonality, our assessment approach for production costs needs to take into account how circumstances differ between Coal Suppliers. In particular, our production cost assessment will have regard to the diverse geology, lifecycle, and history of each individual coal mine.
  - We consider that our assessment approach allows an affected Coal Supplier the opportunity to make submissions to account for any unique features of its coal mine.
- Transparent
  - We have been transparent in our conduct and worked closely with Coal Suppliers, Power Stations, and the NSW and Commonwealth governments to ensure transparency in developing this guidance note.
- Independent
  - The AER is an independent agency, comprising up to 5 board members who are statutory appointments. Current board members are Clare Savage (Chair), Jim Cox PSM, Justin Oliver, Jarrod Ball and Lynne Gallagher.

1.1 Structure of this guidance note

This document is structured as follows:

- Section 2: The AER's role and stakeholder consultation. We provide context on the legislative background pertaining to the coal price cap and our role as the Regulator. We also outline the consultation process we have undertaken in developing this guidance note.
- Section 3: Assessment approach – production costs. We outline the type of cost categories we expect the Coal Suppliers to include in their application including how we may assess these costs.
- Section 4: Assessment of fair margin. We outline the assessment approach we have taken in developing a single definition of fair margin. This section also describes the various criteria that were considered in arriving at a final definition.
- Section 5 – Price cap application process and confidentiality. We outline the step-by-step process for a Coal Supplier to submit an application for a higher price cap, including any associated confidentiality claims.
- Attachment 1 – Required form of application for Coal Suppliers. This attachment provides the form that Coal Suppliers must use when making an application for a higher price cap to the Minister.

2 The AER's role and stakeholder consultation

2.1 Legislative background

On 22 December 2022, the New South Wales (NSW) parliament passed amending legislation to the *Energy and Utilities Administration Act (NSW) 1987* (EUA Act), effecting a price cap on thermal coal sold by specified coal suppliers (Coal Suppliers) to coal fired power stations (Power Stations).[2] Also on 22 December 2022, the NSW Premier, by written order, declared a coal market price emergency pursuant to the EUA Act.[3]

On 23 December 2022, the *Coal Market Price Emergency (Directions for Coal Mines) Notice 2022* and the *Coal Market Price Emergency (Directions for Power Stations) Notice 2022* were made by the Minister based on the declared emergency.[4] These notices made Directions to named Coal Suppliers[5] and Power Stations[6] to effect the cap on prices for coal sold by the Coal Suppliers for use in the Power Stations and prevent the on-selling of capped coal by Power Stations.

On 15 February 2023, the Minister issued revised directions, the *Coal Market Price Emergency (Directions for Coal Mines) Notice 2023*[7] (the Directions) and the *Coal Market Price Emergency (Directions for Power Stations) Notice 2023.*[8] The Directions expand the list of Coal Suppliers subject to the Directions to include a number of export-oriented coal mines. The Directions are in place until 30 June 2024.

There are now 25 coal mines in NSW covered under Schedule 1 of the Directions. The entities operating these mines (with specific mines in brackets) are:[9]

- New Hope (Bengalla)
- Centennial/Banpu (Airly, Mandalong, Myuna, Springvale)
- Glencore (Bulga, Mangoola, Mt Owen, Ravensworth North, Ulan Group; and joint ownership of Hunter Valley Operations, United Wambo JV)
- Delta (Chain Valley, Mannering)
- Peabody (Wambo, Wilpinjong; and joint ownership of United Wambo JV)

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2 Energy and Utilities Administration Act 1987 No 103 (NSW), 22 December 2022.

3 Energy and Utilities Administration (Declaration of Coal Market Price Emergency) Order 2022 made under the EUA Act (NSW) 1987, 22 December 2022. https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2022_2022-600.pdf

4 Coal Market Price Emergency (Directions for Coal Mines) Notice 2022 & Coal Market Price Emergency (Directions for Power Stations) Notice 2022 made pursuant to EUA Act (NSW) 1987, 23 December 2022. https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2022_2022-603.pdf

5 The 23 December 2022 Direction listed 6 domestic-focused coal suppliers, some with multiple mines: Centennial, Peabody Energy, Mach Energy, Newhope Group, Delta Coal and Glencore.

6 There are 5 coal fired generators in NSW and covered by the Direction for Power Stations: Bayswater (AGL), Liddell (AGL) – noting Liddell's imminent closure in April 2023, Eraring (Origin), Vales Point B (Sunset Power International trading as Delta Electricity), and Mt Piper (EnergyAustralia).

7 Coal Market Price Emergency (Directions for Coal Mines) Notice 2023 made pursuant to EUA Act (NSW) 1987, 15 February 2023. https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2023_2023-69.pdf

8 Coal Market Price Emergency (Directions for Power Stations) Notice 2023 made pursuant to EUA Act (NSW) 1987, 15 February 2023. https://gazette.legislation.nsw.gov.au/so/download.w3p?id=Gazette_2023_2023-69.pdf

9 The Directions, Schedule 1.

- Whitehaven (Tarrawonga, Werris Creek, Maules Creek, Narrabri)
- Yancoal (Stratford; and joint ownership of Mt Thorley Warkworth, Moolarben, Hunter Valley Operations)
- BHP (Mt Arthur)
- MACH Energy (Mt Pleasant)
- Idemitsu (Boggabri)[10]

There are 5 coal fired generators in NSW and covered by the Directions for Power Stations:[11]

- Bayswater (AGL)
- Liddell (AGL)
- Eraring (Origin)
- Vales Point B (Sunset Power International trading as Delta Electricity)
- Mt Piper (Energy Australia).

Under the Directions, a price cap of $125 per metric tonne (the cap) is enforced on Coal Suppliers.[12] The cap is the price for coal delivered to the Power Station with energy content of 5,500 kcal/kg. The cap may be adjusted up or down for coal with higher or lower energy content.[13] For example, the price cap for coal delivered to a power station with higher energy content of 6,000 kcal/kg will be $136/tonne, whereas the price cap for coal with a lower energy content of 5,000 kcal/kg will be $114/tonne.

2.2 Who are we?

The AER exists to ensure energy consumers are better off, now and in the future. We are the economic regulator for wholesale and retail energy markets, and energy networks under the National Electricity Law (NEL) and National Electricity Rules (NER). Our functions relate to energy markets in all parts of Australia except Western Australia.

On 13 February 2023, we were appointed as the Regulator under the EUA Act.[14] Our functions as Regulator include assessing Coal Supplier applications to exceed the price cap where the Coal Supplier considers that its production costs plus a fair margin cannot be fully recovered under the cap. Coal Suppliers listed in the Directions who consider that they cannot supply coal at the cap may apply to the Minister for a higher cap.[15] The Minister may then pass on the Coal Supplier's application to us to assess and provide advice. This function is the subject of this guidance note. Other functions undertaken by us under the EUA Act, which are not covered by this guidance note, include:

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[10] Boggabri mine is included in schedule 1, however it has a reservation requirement of 0% (0 tonnes) and therefore is effectively not subject to the cap.

[11] Coal Market Price Emergency (Directions for Power Stations) Notice 2023 made pursuant to EUA Act (NSW) 1987, 15 February 2023.

[12] *Coal Market Price Emergency (Directions for Power Stations) Notice 2023*, Part 2, s.8(1)(b)(i).

[13] For coal with a specific energy other than 5500kcal/kg, the cap is calculated based on the equivalent unit cost of $0.02273/kcal/kg. The Directions, Part 2, s.8(1)(b)(ii).

[14] Instrument of Appointment of the Regulator under Schedule 3 of the Energy and Utilities Administration Act (NSW) 1987.

[15] The Directions, Part 2, s.8(2).

- Receiving monthly reports from specified Power Stations and Coal Suppliers
- Analysing reports for Coal Supplier and Power Station compliance with the relevant Directions, and other market behaviour and outcomes
- Ensuring compliance from Coal Suppliers and Power Stations in regard to their respective Directions.

Section 8(3) of Part 2 of the Directions states that a Coal Supplier's application for a higher cap must be made:

i. in the form approved by the Regulator, and
ii. in the way decided by the Regulator.

The form that Coal Suppliers are required to complete to apply for a higher price cap is included in Attachment 1 to this guidance note.

The application process is the opportunity for a Coal Supplier to provide evidence that its cost of production plus a fair margin for delivered coal to domestic Power Stations, is above the effective cap of $125/tonne (on a 5,500 kcal/kg benchmark). Our role is to perform an assessment of each application and advise the Minister.[16] The decision to alter, or not alter, the price cap will be a decision made by the Minister. If the Minister so decides, the new price cap will apply after Schedule 1 of the Directions is updated and published in the NSW Government Gazette.

Our assessment approach is set out in sections 3 and 4 below. Our expectation is that the Coal Supplier will submit a robust case as part of its application for a higher cap. We will then review the supporting information provided in each Coal Supplier's application for calculating its cost of production and then apply the fair margin, as set out in section 4. Any cost estimate would also be cross-checked with relevant benchmarks or information available to the AER.

Alongside this guidance note, we have commissioned a publicly available report from Wood Mackenzie that provides an overview of coal production in NSW, identifies relevant factors to consider when assessing production costs and advises on an appropriate fair margin.[17] It provides estimates of likely cost categories for NSW coal mines that will be relevant to our assessment of applications for a higher cap. In the public report these figures are aggregated to preserve any individual mine data that might be commercially sensitive. Wood Mackenzie will also provide us with confidential mine-by-mine production cost assessments underlying its sector-wide conclusions.

2.3 Stakeholder Consultation

We recognise the additional regulatory burden imposed on Coal Suppliers as a result of complying with the Directions. Therefore, we have designed this guidance note to ensure that we are able to obtain enough information to make a timely and informed assessment.

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[16] Section 11(2)(a) of Schedule 3 of the EUA Act.

[17] Wood Mackenzie, *NSW domestic coal pricing study, Prepared for the Australian Energy Regulator*, March 2023.

Shortly after the declaration of the coal market price emergency on 23 December 2023, we started to engage extensively with affected Coal Suppliers[18] to inform our understanding on the information requirements in assessing both the cost of production of coal as well as what constitutes a fair margin. During these meetings, we circulated a preliminary outline of our proposed assessment approach. We have received extensive feedback from these meetings which has helped develop our thinking behind this guidance note.

Further to these meetings, we held an online briefing on 9 March 2023 to update stakeholders on the progress of this guidance note. A draft working version of the guidance note, covering production costs only, was circulated ahead of this meeting. This briefing was attended by representatives from Coal Suppliers, Power Stations, government entities and expert consultants. At this forum we presented on key elements of our proposed approach for assessing production costs. We also invited comments from stakeholders on how the fair margin should be defined and assessed.

We consider we have conducted comprehensive consultation on the guidance note while expediting its public release, which reflects general stakeholder sentiment around policy certainty. The majority of stakeholders indicated a preference to have the guidance note published by April 2023 to align with the first round of coal shipments to Power Stations under the Directions.

We intend to continue our open dialogue with Coal Suppliers who are considering seeking a higher price cap, through further bilateral meetings prior to the submission of their application to the Minister. It is important to note that although we provide advice to the Minister, the discretion to decide to alter (or not alter) the price cap rests with the Minister rather than the AER. The submission and review process for a Coal Supplier's application to alter the price cap is set out in section 5 of this guidance note.

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[18] BHP, Centennial, Delta Coal, Glencore, Idemitsu, Mach Energy, Newhope Group, Peabody Energy, Whitehaven and Yancoal.

3 Assessment approach – Production costs

One part of assessing individual coal mine applications for a higher price cap, is advising the Minister on what the AER considers is a Coal Supplier's cost of production for a particular coal mine.

Cost of production typically refers to the expenses incurred from the production and delivery of a particular good or service. In the context of our assessment approach for a higher price cap for domestic shipments of thermal coal, we consider production costs are made up of:

- Core costs that include direct costs related to the extraction and processing of the coal and transport costs for the delivery of a specific shipment of coal. It may also include costs that are not directly attributable to a specific shipment of coal but are nonetheless required expenses to enable the production of this coal and delivery to the generator. This could include costs such as corporate overheads and royalties.
- Non-core costs that are indirectly incurred by the Coal Supplier as a result of compliance with the Directions. Examples of these costs may include incremental take-or-pay costs for rail or port access not associated with delivering coal to the designated generator.

We expect applications, where relevant, to outline how these costs have been allocated to the proportion of coal that is covered by the Directions. Similarly, for any estimates provided on a forecast basis, applications are to include the underlying methodology and assumptions used to arrive at these estimates, including reasons for any deviation from historical trend.

In assessing these applications, we will apply a basic cost approach. Existing contracts and forecasts of historical costs will also be considered alongside other evidence and reasoning put forward by a Coal Supplier. We will cross-reference this with analysis on production cost estimates from our consultant Wood Mackenzie, as well as other public sources of information, such as investor presentations and financial reports.

We will determine whether the application is confined to production costs, as permitted under the Directions. It is important to note that the regime is not intended to be a compensation scheme for Coal Suppliers to recover costs that have not been factored into the cost base until this time.[19] This is because it is a time limited intervention that ends on 30 June 2024. Our understanding of the policy intent underpinning the Directions also preclude the consideration of any opportunity costs that a Coal Supplier may encounter when selling its coal at domestic capped prices as opposed to what it may have earned if exporting.

3.1 Core costs

We define core costs for Coal Suppliers as costs that are either:

- direct costs, and therefore able to be traced back to or are attributable to the extraction and preparation of a particular batch or shipment of coal product; or,

[19] For example, there is often a substantial rehabilitation cost incurred at the end of the mine's life. Provision for this cost is expected to accrue across the entire working life of the mine. See section 3.2 for further discussion on rehabilitation costs.

- indirect costs, where the costs are incurred in the general operation or running of the business, but are still explicitly linked to the extraction, processing, and delivery of coal under the Directions.

Where a cost category falls under indirect costs as defined above, we expect a Coal Supplier's application to include methodology for how these indirect costs have been allocated to the proportion of coal product affected by the Directions. Further guidance on how we expect a Coal Supplier to allocate costs can be found below in section 3.3.

A key part of our approach to assessing production costs is examining past performance. Coal Suppliers, in making an application for a higher cap, are to submit historical cost data for the past two financial years, 2020–21 and 2021–22.[20] From this basis Coal Suppliers should also provide an estimate (or actuals) of cost data for 2022–23 and forecast of costs for 2023–24.

This information should cover the cost categories detailed below and submitted in the form specified in Attachment 1. The historical information provided by Coal Suppliers will inform the AER's assessment of an appropriate cost of production over the Direction period (that is, to 30 June 2024). In particular, we will require Coal Suppliers who are currently supplying coal domestically, or have done so in recent years, to provide their historical contracts, including details of the price, quality and quantity of the sale.

Alongside historical costing information, Coal Suppliers are to provide a set of assumptions and reasoning that sit alongside these costs. This may simply be a description of a feature or property of the relevant coal mine justifying this information. Other forms this information may be provided in are existing or historical contracts, investor reports or audited financial accounts. Where historical spend may not be representative of future costs under the Directions, we expect Coal Suppliers to clearly identify this as part of its supporting information.[21] Further details and the way we require Coal Suppliers to submit their application are included in our approved form in Attachment 1.[22]

Outlined below are the core cost categories we expect a Coal Supplier to submit as part of its application for a higher cap. This list has been informed by the stakeholder consultation we have conducted to date. While the below list is not exhaustive, we consider that it broadly reflects the cost drivers that are central to us forming an assessment of production costs. If a Coal Supplier identifies core costs which cannot be attributed to the following cost categories, it can include additional cost categories in its application. However, in doing so, it must provide sufficient justification regarding the inclusion of the additional cost category, relevance to the delivery of domestic coal as per the Directions, and evidence that it isn't captured elsewhere in our assessment approach.

Direct mining costs

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20 In the event that a Coal Supplier applies for a higher cap once 2022–23 actual data is available, the 2 historical years should encompass 2021–22 and 2022–23.

21 For example, we expect a Coal Supplier to identify if coal processing costs or transportation costs were required for export historically, but some (or all) of these costs are no longer relevant for delivering coal domestically under the Directions. Also see section 3.4 for our assessment approach which details our expectations if costs are expected to escalate materially.

22 While we have listed out a set of cost factors we expect Coal Suppliers to include in its application for a higher cap, this does not preclude Coal Suppliers from proposing additional cost categories that contribute to its cost of production for coal.

As part of this category, Coal Suppliers should submit costs that are directly attributable to the physical extraction of the coal from its coal mine. Justification for these costs may include factors such as whether a coal mine is a surface or underground mine and the depth of the pit and the relative difficulty or and type of technology used in the extraction method. If a mine engages in contract mining, we expect the contract costs as expressed in a dollars per tonne rate to be reported as a direct mining cost.

Coal processing costs

Costs related to processing raw coal into a final product suitable for use in a coal-fired power station should also be included as a component of direct costs of production. In many cases, we expect that base processing (for example, extraction of run-of-mine coal and initial crushing/sizing) will be incorporated into the 'direct mining' cost category above.

However, there may be additional processing and beneficiation costs[23] separately incurred and tracked by the Coal Supplier. We expect applications to identify the processing costs that are relevant for production and delivery of coal for use in a domestic power station. For example, one common process is 'washing' coal to raise its calorific content. This is often done to produce higher energy coal for export purposes. If so, the cost of this processing should not be included when assessing production costs relevant to the Directions, and therefore should not be included in its application (or if it is, labelled clearly to indicate why).[24] If historical processing costs included this type of beneficiation (i.e. to a level above that required for domestic power station use), we will subtract these costs.

Where relevant, we would also expect a Coal Supplier's application for a higher cap to include estimates of costs to process raw coal into other forms or quality levels as required by each of the Power Stations covered under the Directions for Power Stations.

Allocated overheads

Overhead costs are indirect costs that are necessary for the operation of the coal mine, but are not directly attributable to the mining of coal. These costs may vary depending on the operating arrangement the Coal Supplier has for the mine. For those that are operating its own mine, these costs may include labour-related costs and insurance costs.

Broadly, as part of submitting its costs in the form required as per Attachment 1 in this guidance note, we expect each Coal Supplier to clearly itemise and break down its total overhead costs into its relevant components for us to assess. These costs should also be allocated proportionally to the amount of coal being reserved as per Schedule 1 of the Directions.

Transportation costs

Coal Suppliers should submit in their application any costs related to transporting coal to the respective delivery points at each Power Station covered under the Directions. As the

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[23] Beneficiation (or benefaction) means to improve the economic value of raw ore. Beneficiation costs are costs related to the treatment of coal to remove impurities and therefore improve the quality and combustion characteristics of the end product. This is commonly used to improve the sales price (on a per tonne basis) of export coal.

[24] Building on this example further, we understand that a by-product of this process is lower-quality coal that may potentially be dumped by Coal Suppliers as it does not meet export-quality requirements. Insofar as this by-product can then be reused for domestic delivery, we consider it inappropriate to submit these washing costs as a cost of production for this coal.

Directions do not limit the provision of coal to any specific generator, we expect Coal Suppliers to provide estimates of, and our assessment of costs will distinguish and consider, the differing costs to transporting coal to each of the 5 relevant Power Stations (Bayswater, Liddell, Eraring, Vales Point B and Mt Piper).

We expect captive mines to have minimal transport costs when delivering to nearby generators through existing paths such as overland conveyor systems.

Where a coal mine does not have an existing contract or rail path to supply coal to a particular Power Station, we expect its application to include an estimated cost, which may be informed by independent quotes from transport companies that provide the logistics such as Australian Rail Track Corporation, Sydney Trains, and other accredited train operators. An application is also to include reasoning for the cost estimates and a basic methodology, including considerations for congestion.

We are not expecting Coal Suppliers to undertake an onerous exercise when preparing these costings. We acknowledge that in some cases it may be infeasible for a coal mine to supply coal to a certain Power Station due to physical limitations such as uneconomic road routes and lack of permits. Therefore, in such instances, the Coal Supplier should briefly explain in its application why these costings couldn't be provided.

Our approach will be to advise the Minister on a cap based on transport to the most likely generator site, given the location of that mine and any other relevant features. For coal mines in the Hunter Valley, this is likely to be Vales Point or Eraring power stations. But we will also advise on additional increments that could be added to the base cap (or potentially subtracted) to reflect transport to alternative generation sites, where relevant.

Royalties

Royalty payments are incurred based on the total coal sold or consumed from a coal mine, in line with the lease agreement a Coal Supplier has with the NSW Government for each distinct coal mine. We expect royalties to be calculated on the relevant rate (whether underground or open cut mine) as set by the NSW Government. For the purposes of a Coal Supplier including its royalty payments as a cost of production, this should be calculated based on the $125/tonne price cap. This cost would then be scaled up proportionally to the new price cap being proposed in a Coal Supplier's application. For clarity, royalty payments are to be calculated on an as-delivered price basis, which is inclusive of transportation costs.

Total volume produced and calorific content

While total coal production volumes are not a cost category, it is an essential datapoint in determining unit rates. Forecast production volumes may vary depending on, among other factors, the stage of a coal mine's life cycle, disruptions due to weather as well as the quality of the coal seam(s) the Coal Supplier is currently extracting from. As part of our other functions under the Directions, we also receive monthly reporting from the coal mines subject to the Directions, including their production and domestic allocations. We expect that information submitted for volume production to reconcile with the information provided to the AER in other processes.

Likewise, the price cap on coal will vary depending on the calorific content of the coal, in line with the adjustment rate as set out in the Directions. As a result, we also require Coal

Suppliers to break down forecast production levels into varying levels of calorific content. We require that this breakdown first be done on a run-of-mine basis, that is the calorific content of coal directly being mined, prior to any coal processing or washing procedures.

We also understand that some coal mines, particularly those that deliver primarily to export markets, will wash (process) coal prior to exporting in order to achieve a higher calorific content and therefore energy rating. Where this occurs, we also require Coal Suppliers to provide the resulting coal volumes, calorific value and yield percentage (a measure of the amount of coal lost through washing). A by-product of this washing process is coal that does not meet the appropriate quality standards for export purposes. However, in some cases this lower quality coal may still be suitable for delivery to domestic generators. Where this is possible, we expect this volume of coal to be considered and included in the information provided alongside historical production volumes.

3.2 Non-core costs

We expect certain Coal Suppliers may incur potentially significant additional costs related to implementing and abiding by the requirements of the Direction that they would not normally be exposed to. We have recognised these types of costs as non-core costs and expect these may be particularly relevant for export-oriented Coal Suppliers. Broadly, we define non-core costs to be unavoidable indirect costs incurred by the Coal Supplier which are attributable to the fulfilment of its obligations under the Directions, and which are separate from the direct costs related to the extraction, processing, and delivery of its core coal production.

These may include:

- **take-or-pay costs** – these are costs incurred when a Coal Supplier is unable to deliver the agreed-upon amount of coal. We understand that these contracts are generally related to rail and ports, where the Coal Supplier will incur the full costs of the use of the rail or port regardless of whether it no longer requires or is unable to use the full capacity of the service.
- **stockpiling and handling fees** – these are costs incurred due to holding coal in storage, in compliance with the Directions. Also included here may be configuring infrastructure and establishing a pad on land to stockpile coal, as well as any costs associated with maintaining this stockpile including for mitigating environmental, health and safety impacts
- **rehabilitation costs –** these are costs expected to be incurred at the end of the mine's life to stabilise and restore the environment around the mine site. The rehabilitation conditions are usually specified as a permitting requirement. This indirect cost shares some features with other corporate overheads, but is distinguished by the expectation that provision for these costs is accrued incrementally over the expected life of the coal mine.

It is important to note that we consider that an application that includes non-core costs as a cost of production must be able to identify the marginal and/or incremental costs incurred due to the Directions. Non-core costs that were already being incurred by the Coal Supplier, unrelated to the additional portion of domestic produced coal, are not to be factored in as a cost of production for the purposes of the Directions.

In assessing whether non-core costs should be included as a cost of production, we will have regard to expert advice received by the AER. We will also assess the evidence and justification for these costs provided by the Coal supplier.

We expect, as an efficiently run business, a Coal Supplier will ensure only efficient costs are submitted in its application by recalibrating its production levels, restructuring its rail and port arrangements and or some of its forward coal shipments. We would therefore expect an application to contain supporting information around the strategies it has considered and implemented to minimise non-core costs.

3.3 Cost allocation

To accurately determine an appropriate cost of production, we require each Coal Supplier to submit its methodology for allocating costs to the proportion of coal covered by the Directions. This should be accompanied by brief reasoning and justification behind its proposed methodology.

The allocation approach may differ depending on the cost category and whether the coal mine also exports its coal. Costs such as transportation and overheads may be allocated proportionally, with a justified proportion allocated to domestic shipments reflecting the differing logistical requirements for delivering coal to domestic generators as opposed to export ports. For non-core costs such as stockpiling costs and take-or-pay costs, the application should explain what portion is to be allocated as a cost of production for the purposes of the Directions. Allocation of rehabilitation costs, if relevant, should take into account the overall operating life of the mine. Our assessment approach will involve reviewing the reasonableness of the proposed cost allocation methodology including identifying costs that are attributable only to the domestic provision of coal under the Directions, with reference to industry standards and consultant reports where appropriate.

We are also aware that some coal mines extract, as a by-product, both thermal and metallurgical coal. As the Directions only cover thermal coal for use in power generation, we expect coal mines that produce both types of coal to identify and isolate the production volume of thermal coal from the total output volume. Cost allocations should then be done on a thermal coal basis.

Below are two simple examples of how a Coal Supplier may choose to allocate its production costs to the proportion of coal for domestic consumption. Note any figures quoted below are not representative of our expectations for how Coal Suppliers are to allocate costs and are instead purely for illustrative purposes.

Example 1 – Allocation methodology for indirect costs:

Assume a Coal Supplier owns 2 coal mines, one of which is submitting an application for a higher cap. The total production output for each mine is 1Mt of coal per annum, all of which is thermal coal. Of this total production, coal mine A will deliver all its production (1Mt) for domestic use. Coal mine B (the mine applying for a higher cap) delivers 0.5Mt for domestic consumption and exports the other 0.5Mt.

Suppose that the Directions requires coal mine B to reserve an additional 20% of its export production for domestic consumption. This would result in coal mine B needing to allocate an additional 0.1Mt from its export volume for domestic purposes (for a total domestic production of 0.6Mt).

To start, we expect there are certain core costs such as direct mining costs and processing costs that can be identified on a dollars per tonne basis to be allocated to domestic production, regardless of the volume allocated.

However, there are other, primarily indirect core costs such as overheads, that are whole of business or are not distinct costs related to a particular product. To calculate a dollars per tonne value, the Coal Supplier will first establish an allocation based on production at a particular mine. Under this example scenario, overheads would be split equally between mines A and B. A similar proportioning will be made for overheads allocated to mine B to determine the split between domestic and export coal. By multiplying these two proportions together,[25] an allocation of 30% of total overheads for the Coal Supplier are related to domestic coal production for coal mine B. This is the base case scenario for cost allocation in this example.

There may be, however, certain factors that may influence the allocation of resources resulting in a final allocation that may be higher (or lower) than the base case of 30%. For instance, there may be extensive logistical difficulties in redirecting this coal due to rail congestion and the need to hire a higher proportion of staff facilitating transport of coal to multiple domestic generators. On the other hand, there may be cases where due to already established relationships and efficiencies in facilitating the production and delivery of coal to domestic generators, the increase in overheads is proportionally smaller than the base case.

The Coal Supplier is to submit evidence such as relevant financial calculations or existing signed contracts in its application justifying any alternative allocation from the base case scenario.

Example 2 – Allocation methodology for domestic stockpiling costs:

Assume a Coal Supplier is applying for a higher cap for its two coal mines, mine A and mine B. Both coal mines have a total production output of 1Mt of coal per annum, all of which is thermal coal. Mine A delivers 0.5Mt for domestic consumption and 0.5Mt for export purposes. However, mine B does not participate in the domestic market and delivers all of its production (1Mt) to port for overseas sale. The export coal typically is sent to port as soon as possible, so there has been no need for a large stockpile at mine B in the past.

Suppose that the Directions stipulate for this Coal Supplier for both of its coal mine that 10% of its export coal is to be reserved for domestic consumption. This would result in coal

[25] This can be illustrated through the following formula: 50%×(50%+20%×50%). This represents that of the total overheads, 50% is allocated to coal mine B. Within this 50%, a further 50% of overheads is fully allocated to already existing domestic production. We then include an additional 20% of the remaining 50% overheads for export purposes to reflect the redirected coal.

mine A reserving an additional 0.05Mt for domestic consumption (for a new total of 0.55Mt), while coal mine B needs to newly allocate 0.1Mt for domestic consumption.

Coal mine A

We expect the additional costs for stockpiling an additional 0.05Mt of coal for domestic production to be in line with existing stockpiling costs. Our base case approach to allocation is that it should be done on a proportional pro-rata basis. If these costs do not reflect historical or its ongoing dollars per tonne rate, the Coal Supplier is to provide evidence on an alternative allocation approach. For example, if the Coal Supplier does not require additional storage facilities as its existing stockpiling capacity can manage the increased amount.

Coal mine B

As coal mine B has never sold coal on domestic markets, it will need to newly establish stockpiling facilities and other related costs to ensure it can reserve its required 0.1Mt ready for delivery. We would expect coal mine B to obtain quotes on storage and stockpiling costs, which would be solely allocated to the domestic production at coal mine B, and then allocated based on expected volumes for a dollars per tonne basis. Information from costs at coal A would be a starting point for estimating variable costs relating to maintaining safety and mitigating health concerns around the stockpiling coal. Any divergence from this rate should have accompanying evidence setting out the reason (e.g. climate/weather differences between mine A and B leading to different safety requirements).

3.4 Forecast estimates and cost escalation

In assessing the cost of production in an application for a higher cap, we also require Coal Suppliers to provide estimates for 2022–23 (if relevant) and forecasts for 2023–24 of each cost category outlined in core costs (section 3.1) and non-core costs (section 3.2).

Where a Coal Supplier is making an application before 2022–23 information is available, it should provide estimates based on the best information available to the Coal Supplier at the time it makes an application. This estimate for the 2022–23 financial year may then inform its forecast for the 2023–24 period.

Our expectation is that any forecast estimate submitted should be based on a Coal Supplier's historical costs of the previous 2 financial years as per the information we require to be submitted alongside its application. From this basis, Coal Suppliers may choose to escalate their reported historical costs for any expected variations in the base cost categories due to the prevailing economic conditions. Any deviation from historical trend must be justified with appropriate evidence and detailed assumptions, including forecast expectations around inflation, material and labour costs, and any mine-specific factors that may impact production levels.

The final estimate produced should be a single figure that covers the period to 30 June 2024 for which the Directions apply.

4 Assessment of fair margin

We understand that the $125/tonne price cap for coal is intended to cover a Coal Supplier's production costs plus a fair margin. Therefore, in assessing an application for a higher price cap, we need to advise the Minister on a 'fair margin' that the Coal Supplier should receive in supplying thermal coal to domestic Power Stations under the Directions. The decision on the fair margin to be applied in each case remains the prerogative of the NSW Government, in consultation with the Commonwealth Government.

'Fair margin' is not a defined term in the EUA Act or the Directions, and as such is a matter of regulatory judgement, having regard to our understanding of the government's policy intent. In this chapter we set out how we have defined what a fair margin is, our approach to estimating a fair margin, and how we have implemented this approach to arrive at our view of what a fair margin should be.

Based on the analysis described in section 4.3 of this guidance note, we have calculated a fair margin of $18/tonne that should be applied to Coal Suppliers covered under the Directions in the period through to 30 June 2024.

4.1 Conceptual basis for defining the fair margin

In developing our approach to calculating a fair margin, we considered that an appropriate fair margin should have the following characteristics:

- The fair margin should relate only to domestic thermal coal production, in line with the type of coal shipments covered by the Directions.
- The fair margin definition should be complementary to our assessment of production costs, with no double counting (or omission) of relevant costs.
- The fair margin should reflect the long-term average, in order to provide a stable margin that would apply regardless of the movement in future commodity cycles.
- The fair margin should reflect the margin on existing investments—with the intention that it is to support the ongoing operation of the coal mines named in the Directions.
- A practical and streamlined fair margin assessment is preferable to a margin calculated through a process involving a materially greater regulatory burden.
- The fair margin is consistently defined as a sector-wide benchmark in dollars per tonne, applied equally across all Coal Suppliers and mines.

We consider that these characteristics define a fair margin that is fit for purpose, having regard to the context of the Directions and our understanding of the government's policy intent.

We explain each of these characteristics in turn below.

The fair margin should relate only to domestic thermal coal production, in line with the type of coal shipments covered by the Directions

Central to our approach is that the fair margin is to relate only to domestic thermal coal production. This flows from the domestic nature of the coal shipments specified in the

Directions and aligns with the core policy intent of the intervention. The defined fair margin reflects coal production of a suitable quality for domestic power stations, delivered using the domestic transportation network.

The fair margin is not the opportunity cost or 'lost revenue' from selling domestically instead of at (currently higher) export prices. This also means that we will assess the required fair margin on domestic coal separately from any export coal that a Coal Supplier might also produce. For example, we will not net off low domestic margins against high margins that may be achieved on export coal. This provides for consistent assessment between those mines producing for domestic purposes and those producing for both domestic and export purposes.

On similar grounds, we will assess the required fair margin on thermal coal separately from any metallurgical coal that a Coal Supplier might produce.

The fair margin definition should be complementary to our assessment of production costs, with no double counting (or omission) of relevant costs

It is important that production costs and fair margin form a joint package such that there is no double-counting, or omission, of relevant costs. Some cost components could be accounted for as either a production cost or in estimating a fair margin.

For example, the cost components for tax and depreciation (return of capital) can be separately estimated and included in a build-up of production costs. As such these costs should be excluded from the fair margin estimate. All else equal, the estimate of fair margin will be lower.

Alternatively, these cost components could be excluded from the production cost build up. If so, the costs should be included in the fair margin estimate, and all else equal the fair margin estimate will be higher.

While either approach is possible, our preferred approach is to include these costs in estimating a fair margin. We consider that this approach results in a broadly defined fair margin that includes the return on capital (dividends and interest payments), return of capital (depreciation) and tax.[26]

The fair margin should reflect the long-term average, in order to provide a stable margin that would apply regardless of the movement in future commodity cycles.

We acknowledge that coal, as with all commodities, experiences large swings in value across time. The nature of our fair margin is that it will provide a specified stable return without upside or downside risk. Any changed cap will be binding through to the end of the Direction period, regardless of subsequent movements in coal market prices (either up or down).

The nature of this intervention is a short-term, limited period of a coal mine's effective life, specified as a 15-month period from April 2023 through to June 2024, and each mine is capped with respect to the amount of coal it must supply. This supports a definition which is

[26] This approach broadly aligns with the often-used EBITDA metric—Earnings Before Interest, Tax, Depreciation and Amortisation.

built on a long run view that (ex-ante) averages through the highs and lows of commodity cycles.

The fair margin should reflect the margin on existing investments— with the intention that it is to support the ongoing operation of the coal mines named in the Directions.

The narrow time frame for the intervention also supports a view that the fair margin should reflect the margin on existing investments— with the intention that it is to support the ongoing operation of the coal mines named in the Directions, as opposed to enabling new investments. The Directions also only cover the specified Coal Suppliers rather than any potential entry by a new mine. Therefore, any margin will, in practice, compensate existing coal mines and existing capital investment.

Coal mines are capital intensive and there will be ongoing replacement capex, but the expectation is for overall flat or declining real asset base values given the long-term outlook for domestic thermal coal production. While there are risks with an existing Coal Supplier applying to extend its lease or permit for a particular coal mine, we do not consider this changes the primary nature of the relevant investments during the limited period of intervention.

A practical and streamlined margin assessment is preferable to a margin calculated through a process involving a materially greater regulatory burden.

The policy intent is for an immediate intervention, as befitting an emergency declaration, but for a relatively limited period. There is a short window between the expansion of coverage in the revised Directions (15 February 2023) and the first possible shipments from new mines which have been included in the revised Directions (from 1 April 2023). As such, there is considerable stakeholder interest in having an expedited process—not just for the development of this guidance note, but also for the preparation and assessment of applications for a higher price cap.

A detailed bottom-up approach to calculating the fair margin will necessarily involve significant time and effort. The assessment of fair margin might include a number of matters where there is no practical upper bound to the amount of time that could be spent.[27] This imposes considerable direct costs on a Coal Supplier, as well as delaying the date of any potential decision by the Minister to raise the cap.

As such, our preference is for a practical approach that produces a reasonable estimate of fair margin without imposing such an undue regulatory burden on stakeholders. This includes targeting a higher-level definition of fair margin that implicitly includes difficult-to-estimate components (such as the rate of return or relevant capital base). It also means accepting a reasonable level of accuracy, rather than striving for precision in fair margin calculation.

The fair margin is consistently defined as a sector-wide benchmark in dollars per tonne, applied equally across all Coal Suppliers and mines.

Based on our understanding of the policy direction from the NSW Government, our advice on fair margin will be provided as a single definition, such that it can be applied consistently

[27] As an example, the AER is legislatively required to conduct a detailed review of the rate of return on capital for gas and electricity networks every four years. Following the conclusion of each review and publication of a revised Rate of Return Instrument, work on the next one commences immediately.

across all coal mines applying for a higher cap. We also seek to provide consistency in the fair margin for those coal mines remaining under the default cap and those who end up with a higher cap.

The consistent sector-wide fair margin is to be paired with an estimate of production costs that is specific to each mine. In our discussions with Coal Suppliers, there were persuasive cases presented for material variation in production costs for specific mines, often reflecting aspects of a mine's geology or history.

We have evaluated how to specify a consistent fair margin. The cap is specified in dollars per tonne, so any other basis must eventually be converted to that form. We have given careful consideration to whether a consistent fair margin should be specified as a percentage of production costs, such that the fair margin (in dollars per tonne) would scale with costs for each mine. As is explained in section 4.3 below, the evidence on historical margins did not suggest that scaling in this way would be more likely to fairly compensate Coal Suppliers.

A 'dollars per tonne' consistent fair margin for all Coal Suppliers is also readily explained and understood.

Finally, a sector-wide approach to fair margin will materially reduce the regulatory burden on Coal Suppliers in making an application for a higher cap. There is no requirement for a Coal Supplier to invest time (or engage expert consultants) to tailor an estimate of required fair margin for its specific circumstances.

Criteria used in evaluation of approaches

The characteristics described in the section above define what the fair margin is, and some aspects of how it should be measured. To evaluate approaches to implementing these definitions and calculating a subsequent fair margin, we considered and applied the criteria set out in Table 1.

Table 1 Criteria for evaluation of fair margin approaches

Criteria	Core concept	AER preference
Efficiency	How readily the approach can be implemented, including the time taken and costs of doing so. This includes the administrative burden on Coal Suppliers preparing an application, as well as on the Regulator in assessing an application.	In keeping with our definition, our preference is for an approach that is practical, timely and avoiding spurious precision.
Simplicity	How easily the approach can be understood and applied by stakeholders.	We prefer an approach that is simple and easy to understand.
Transparency	How replicable the approach is and clarity around how the regulator has arrived at its estimates.	We prefer transparent approaches, including the extent to which the estimate was readily seen to align with our fair margin definition.
Consistency	Whether all coal mines are treated equally, and the degree to which sector-wide outcomes will apply to all firms.	We prefer an approach that will result in consistency for all firms.
Accuracy	How accurate is the approach, both in terms of minimising the size of any error and any bias for too high or too low fair margin.	We prefer an approach that estimates a fair margin with reasonable accuracy, consistent with our definitions.

4.2 Sales-revenue-less-cash-costs approach to fair margin

After considering the context and criteria set out above, we have adopted a 'sales-revenue-less-cash-costs' approach to calculating the fair margin. To perform this calculation, we have relied primarily on the Wood Mackenzie subscription data as our underlying dataset:

- AER analysis was conducted on the domestic, thermal coal supply cost dataset available under a Wood Mackenzie subscription. This dataset includes mine specific estimates of costs (in detailed cost categories) and sale prices going back to 2000. It covers all NSW mines (and so all mines specified in the Directions), standardised to a 5,500 kcal rating.
- As supporting data sources for this approach to triangulate the fair margin, we have also relied on:
  - Expert commentary on the relevant fair margin from Wood Mackenzie as part of their public report (released alongside this guidance note).
  - Sample verification of the Wood Mackenzie dataset against publicly available quarterly production data published by Coal Suppliers

As is evident from the label, the core calculation implements the fair margin as the difference between sales revenue and cash costs. Under this approach:

- Coal sales revenue (and sale prices in dollars per tonne) is a headline figure that is tracked and reported on a relatively consistent basis across the sector. The observations can be made on a dollars per tonne basis, or in total dollar figures which are then converted to dollars per tonne using sales volumes.
- The coal industry conventionally tracks and reports its production costs on a cash basis, so this measure is practical and readily understood by Coal Suppliers. The cash costs will align with those described in the production costs section of this guidance note. We are generally able to reconcile this measure back to statutory accounting in annual financial reports, though it is important to correctly allocate the relevant portion (i.e., costs pertaining to domestic thermal coal, in line with our fair margin definition).
- There are a number of non-cash cost categories that will be material expenses for Coal Suppliers. These will be implicitly included in the margin calculated under this approach. There is convergence with the general 'Earnings Before Interest, Tax, Depreciation and Amortisation' (EBITDA) metric used in many industries. No explicit calculation of the rate of return (or capital base) is required.
- Observations of revenue and costs need to be considered over a long time series. Averaging across this time series allows us to look through the ups and downs of the commodity cycle, in keeping with the relevant definition of fair margin. There is some tension, however, because we still must consider if there is structural (rather than cyclical) variation in average margins over time that should be accounted for in the fair margin we determine.
- To obtain the sector wide fair margin, we take an average (simple average, median, weighted average or some other central measure) across time and across many coal mines. Ideally all observations would pertain to mines that only produce domestic thermal coal. In practice, we will observe many entities with varying degrees of

alignment to this definition, and so need to consider the allocation of revenue and costs back to the relevant shipments.

Whilst this approach may not explicitly quantify some cost components, we consider it nonetheless provides a reasonable benchmark margin sufficient to cover these expenses over time. Given our assessment of production costs in section 3 above excludes interest, tax and depreciation, then this fair margin allows for:

- a return on capital commensurate with the risk of domestic thermal coal production for Australian power plant consumption
- a return of capital in line with the economic deprecation of the assets of the firm associated with this domestic coal production, and
- corporate taxes expected to be paid by the firm on profits from domestic thermal coal sales.[28]

Our fair margin is to be applied consistently for all coal mines covered in the Directions, as discussed above. We have determined that a sector-wide benchmark invariant to changes in production costs (specified in dollars per tonne) is the better approach to take in these circumstances. This approach is consistent with our view that margin requirements are relatively constant across Coal Suppliers once adjusted for volume.

We consider that this approach is relatively simple and can therefore be easily understood by stakeholders. We also consider this approach will be efficient to implement and reduce the regulatory burden associated with Coal Suppliers preparing their applications and the administrative burden on us to assess such applications in a timely manner.

4.3 Derivation of the fair margin

In adopting the sales-revenue-less-cash-costs approach, we have determined a fair margin of $18/tonne ($2023) for 5,500 kcal/kg coal. The key elements in our analytical approach are described below.

Wood Mackenzie dataset

The analysis underpinning the calculated fair margin amount is based on a coal industry dataset available under a Wood Mackenzie subscription. We have chosen to rely on the Wood Mackenzie data for the following reasons:

- Consistency in methodology – Wood Mackenzie applies a consistent methodology in its calculation of costs for all coal mines. This allows for a reasonable comparison of margins across not just coal mines, but also across time. Other sources of information such as publicly available financial reports are not directly comparable across Coal Suppliers due to differing assumptions and reporting standards. Similarly, Coal Suppliers may have shifted accounting standards and reporting frameworks over time, which introduces issues with assessing margins for a Coal Supplier over time.
- Reliability of information – Wood Mackenzie's dataset is sufficiently detailed with individual cost categories across coal mines throughout time. This level of information is

[28] Royalties are recorded separately from general taxes and are included as a specific cash cost separate from the fair margin.

generally unavailable when examining financial reports, as Coal Suppliers do not provide costs broken down to the granular detail that we require in assessing a fair margin for domestically provided coal in NSW. Furthermore, there are a limited number of Coal Suppliers that provide publicly available financial reports.

- Alignment to the Coal Mine Directions – the Directions explicitly refer to the delivery of coal for domestic production. This requirement should be explicitly reflected in any fair margin derived for application in determining a price cap for coal produced under the Directions. Wood Mackenzie's dataset distinguishes between coal produced for the domestic market and export production.

Weighting by production volumes

There are a number of data points with extreme high or low values relative to the majority. We consider that a level of judgement must be applied to determine whether these data points represent the standard cost structures typical of a coal mine during normal operating conditions. Without adjusting for these outliers, a few large negative (or positive) margins will have a material impact on calculating any industry average of fair margin.

However, we have observed that significant outliers typically have low volume, reflecting unique circumstances that the coal mine was experiencing over the relevant period. Low production volumes are also correlated to high costs and consequently atypically low or negative margins. This reflects our understanding that coal mines incur relatively high fixed costs when extracting coal, with the low or negative margins representing an inability to spread these costs across an efficient production volume.

As a result, our preferred methodology weighs the cash margins by the production volumes of the coal mine, in relation to the broader industry during that year. This approach enables us to smooth out the impact of any anomalies occurring at a particular coal mine for the year.

Escalation of observed fair margin by inflation

The cost data contained in Wood Mackenzie's dataset has been updated for quarter 1 of 2023, which includes an estimate of costs for the 2023 calendar year. However, we consider it inappropriate to include cost estimates for the period that overlaps with the duration of the Directions. We have therefore taken a time series of cost data up until the end of 2022.

Given our fair margin is to cover the period 1 April 2023 to 30 June 2024 (15 months), we have escalated our fair margin from an amount expressed in end-of-year 2022 dollars to a forecast nominal value as at 31 December 2023. This represents approximately the mid-point of the period covered by the Directions, consistent with our requirement in section 3.4. We have applied a forecast inflation of 4.8% for the year to December 2023 in line with the RBA's February 2023 Statement on Monetary Policy.[29]

Length of time series

In assessing historical margins on EBITDA, we have adopted a 15-year period as our preferred time horizon over which an average is calculated. We consider this to be appropriate for the following reasons:

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[29] RBA, *Statement on Monetary Policy*, Appendix: Forecasts, February 2023. Available at https://www.rba.gov.au/publications/smp/2023/feb/forecasts.html, accessed 26 March 2023.

- Short/medium-term variation in margins – as per the Wood Mackenzie report published alongside this guidance note, coal price cycles are typically 6–7 years.[30] Cycles of this approximate length can be observed in Wood Mackenzie's subscription dataset for annual margins, particularly during recent years.[31] More broadly, we have observed that margins are not particularly stable and vary significantly year-on-year. As we consider that the fair margin should reflect a long-term stable average, we consider any fair margin estimation period should adequately cover both the peaks and troughs of the coal price cycle, so as not to skew the long-term average.
- A 7-year period (representing a single coal price cycle) would be more susceptible to outliers or anomalous years. In particular, data between 2018–2021 illustrates a more than $20 variation, from peak to trough, in the industry average margin. Extreme movement in the average cash margin for any particular year would have a significant and undesirable impact on the final estimate of fair margin.
- On the other hand, a 23-year period (from 2000, the start of this century), may reflect outdated data or operating environments that are no longer relevant or applicable to coal mines operating today. We have considered whether the variation in average margins between a 23-year and a 15-year time horizon may be structural.

Results – AER analysis of Wood Mackenzie dataset

Our primary findings are shown in Figure 1, which presents a year-by-year view of margins for domestic thermal coal, consistent with our sales-revenue-less-cash-costs approach.

Figure 1 Weighted average year-by-year margin –analysis of Wood Mackenzie dataset

[30] Wood Mackenzie, *NSW domestic coal pricing study, Prepared for the Australian Energy Regulator*, March 2023, p. 26.

[31] There is variation in cycle lengths, and in particular the previous cycle appears longer than average—roughly 9 years from 2009 to 2018 (peak to peak) or from 2012 to 2021 (trough to trough).

Figure 1 illustrates the average margins for NSW domestic coal mines over 2000–2022 from the Wood Mackenzie dataset. These values have been calculated by weighting each mine's margin by its annual production volume proportional to the total production volume for all domestic coal mines in NSW for that year. This means mines producing more coal in a particular year have a larger impact on the weighted average than mines producing proportionally less coal in that year. We have then combined this to form an industry-wide margin. As can be seen in this graph, there are marked cycles of decreasing then increasing margins across this time period.

There is also variation across time in the peaks and troughs of the cycles. The low point of each cycle (trough) has shifted upward slightly through time. Likewise, peaks are also showing a larger increase, particularly in the most recent years (peaking in 2017–2018). Our preferred observation period is 15 years, which captures two peaks and troughs, which we have interpreted as two full coal price cycles. This reflects the need for a time series that averages out the highs and lows to estimate a long-term average. It also has regard to potential structural changes over time making older data less relevant. The dotted grey trend-line illustrates an increase in the average margin across time – an observed increase of $7/tonne throughout the 23-year dataset.

Figure 1 also shows an average (green line) and median (orange line) over our preferred period of 15 years.[32] We observe an average margin of $14.4/tonne, and a median margin of $16.8/tonne (both in real 2022 dollars). By construction, the median places less weight on the magnitude of the peaks and troughs, and this appears preferable given the evident year-to-year variability. The median also coincides with the long-term trend line in 2022, the final year of our dataset.

To place this analysis in context, we also considered several other aggregation approaches, summarised in Table 2. The bottom two rows in this table (in bold) reflect the approach presented in Figure 1 above.

Table 2 Alternative analysis of Wood Mackenzie dataset

Aggregation method	Explanation	15-year series (2008–2022) $/tonne	23-year series (2000–2022) $/tonne
Average	Average of all observations in the dataset, without distinguishing years or mines.	8.4	9.1
Median	Median of all observations in the dataset, without distinguishing years or mines.	13.0	11.7
Average of annual medians	Calculate median for each year (across all mines, no weighting for production volume), then take the average across all years.	15.5	13.7
Median of annual medians	Calculate median for each year (across all mines, no weighting for production volume), then take the median across all years.	16.1	12.8

32 For clarity, the green line is the average of the weighted average year-by-year results; the orange line is the median of the weighted average year-by-year results.

Average of weighted average mine-by-mine	Calculate the weighted average for each mine (each year weighted by production that year against the total production for that mine over time), then take the average across all mines.	6.5	8.1
Median of weighted average mine-by-mine	Calculate the weighted average for each mine (each year weighted by production that year against the total production for that mine over time), then take the median across all mines.	9.6	10.7
Average of weighted average year-by-year	**Calculate the weighted average for each year (each mine weighted by production volume that year against total production that year), then take the average across all years.**	**14.4**	**13.3**
Median of weighted average year-by-year	**Calculate the weighted average for each year (each mine weighted by production volume that year against total production that year), then take the median across all years.**	**16.8**	**13.4**

Note All figures are in real 2022 dollars.

When evaluating the alternative approaches in Table 2, we had regard to a number of factors:

- **Outliers** – there are extremely high or low margin values (relative to the majority of results) calculated for particular mines, or particular years. As already noted, including these outliers in an average will materially alter the overall margin calculation. Applying a median approach will reduce this effect. A weighted average may also minimise the effects, where the weighting approach intersects with the underlying cause of the high/low values. Finally, complete exclusion of the outliers can be an option—but this does make it important to objectively assess which data points are outliers, which may be contentious.
- **Low production years** – there are some years where there is materially lower production for some mines, relative to that mine's usual production. This is most evident in recent years, which we understand is primarily because of Covid-19 and/or flooding interrupting production. There is an open question as to how representative these datapoints are of the industry-wide fair margin. The 'weighted average mine-by-mine' approach will directly reduce the impact of low production years. The length of the dataset (15 and 23 years) also assists with minimising this issue, sampling both the good and bad years in proportion over this period.
- **Low production mines –** there are some mines that overall produce materially less thermal coal than the majority of mines in the dataset. As a result, the margin for these mines may not be representative of a typical mine and may skew any calculation of an industry-wide fair margin. This is particularly an issue with the 'weighted average mine-by-mine' approaches, where the weighting addresses variation, or anomalies, in production for a particular year but is unable to account for coal mines with systemic issues.

On balance, we consider the median year-on-year weighted approach of $16.8/tonne ($2022) addresses, or minimises, all the issues listed above and best aligns with the characteristics in section 4.1. Specifically, it is an industry-wide long-term average margin for

NSW domestic producers of coal. This approach is simple and easily understood by stakeholders, provides a consistent fair margin to all applicants and is relatively transparent.

In recommending a 15-year period (approximately two cycles), we have evaluated the benefits of a longer time series (i.e. larger sample providing a better estimate of the underlying margin) and a shorter time series (i.e. shorter sample containing more recent and relevant data). Our selected approach aligns with the endpoint of the rising linear trend in the year-by-year data. Although it is the highest of the aggregation measures considered in Table 2, it still sits below the higher fair margin proposed in the Wood Mackenzie report ($21.7/tonne, as described below).

This calculation is in real 2022 dollars. In line with our expectation that the price cap should be applied for the entire period of the Directions, we have escalated this value to nominal December 2023 dollar terms, which is approximately the midpoint of the Direction period. Our approach to doing so is escalating the $16.8/tonne by the RBA's February 2023 *Statement of Monetary Policy* forecast of CPI for December 2023 of 4.8%. This produces a value of $17.6/tonne in forecast 2023 dollars (i.e., as at 31 December 2023).

We have also considered the relative precision of our fair margin estimate. We have explicitly adopted a practical and streamlined estimation approach, and do not consider that this warrants application of an overly precise fair margin. The default cap was expressed in whole dollars and our approach to estimating production costs is also likely to be similarly expressed. Accordingly, we round to the nearest dollar in determining a final fair margin value of **$18/tonne** to be applied across the Direction period.[33] This value is for 5,500 kcal/kg coal, noting that any adjusted cap would be applied with regard to the linear scaling based on energy content specified in the Directions.

Consideration of scaling the fair margin estimate

We have considered the case for specifying a consistent fair margin as a percentage of costs, rather than as a fixed dollars per tonne. This would produce different final outcomes for different mines, with those mines with higher production costs receiving a higher fair margin in dollars per tonne. As noted in Wood Mackenzie's report (and discussed below), there was some historical precedent for scaling the margin as a percentage of costs. The initial reasoning might have been that higher costs required higher returns.

We performed an analysis on the relationship between observed margins (calculated as sales-revenue-less cash costs, consistent with our approach above) and the overall level of cash costs. By examining the historical margins for mines with lower costs against margins for mines with higher costs, we can see if a fixed dollars per tonne amount is appropriate, or whether a scaling proportion is more reflective of cash margin requirements.

Our findings suggest that, if anything, the cash margin is *inversely* proportional to costs. Lower cost coal mines are likely to have higher margins, while higher cost coal mines had lower margins. Intuitively, this would make sense if supply of domestic thermal coal is

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[33] Applications for a higher price cap may be made at any time, potentially meaning that we have later inflation forecasts (or even inflation outcomes) available to us at the time of an application. We do not propose to vary our fair margin estimate to account for any later inflation evidence—but this is because of the level of estimation inherent in our calculation of the fair margin and our rounding approach.

constrained by competitive pressures. Those mines with a cost advantage (that is, lower costs) can sustain higher margins when bidding against competitors who need to cover their higher cost base. Also, there were instances where a coal mine incurred higher costs relative to their usual baseline in a particular year, and consequently reported lower margins. This is consistent with contracted supply preventing re-pricing in response to unforeseen (but temporary) production constraints.

However, there is significant variability in margins that makes drawing a firm conclusion on inverse scaling difficult. Outliers also potentially skew the dataset and creates a bias for negative margins at the higher cost end of the spectrum. On balance, there is no evidence that a percentage of costs approach would provide a more accurate fair margin, and we consider a flat dollars per tonne benchmark fair margin to be an appropriate measure.

Estimates from Wood Mackenzie report

Wood Mackenzie provided expert advice to the AER on how a fair margin could be estimated consistent with the characteristics set out in section 4.1. Based on its analysis, Wood Mackenzie recommended that a fair margin of $21.7/tonne (in 1 Jan 2023 dollars) for 5,500 kcal/kg coal be applied to each Coal Supplier's production costs.[34]

Wood Mackenzie applied a different methodology to that used by the AER, even though the underlying dataset was the same. We summarise the Wood Mackenzie estimation approach in Table 3, alongside our consideration of the key points.

Table 3 Key points from Wood Mackenzie calculation of fair margin

Category	Wood Mackenzie fair margin calculation	AER consideration
Time period	Wood Mackenzie conducted the fair margin analysis for the 6-year period between 2016–2021. Wood Mackenzie considered this period to extend across a time span representative of a typical commodity price cycle, commonly thought of as 6-7 years.	We have chosen to place weight on a longer time period to ensure that our fair margin reflects average outcomes across multiple cycles. We consider the larger sampling period provides a better estimate of the underlying margin across up and down periods. Wood Mackenzie's recommended time period of 2016–2021 also appears to include an extended period of relatively high (compared to historical) margins. This would also be inconsistent with our definition of fair margin having regards to long-term averages. In particular, while we note that Wood Mackenzie's time series on prices demonstrates stable prices from 2012 onwards (meaning there should be relative indifference in choosing a sample size within this time period, relative to price), our analysis of margins through the same time period demonstrates a clear upwards skew in margins for Wood Mackenzie's chosen time horizon. Given our analysis is ultimately on a fair margin, we consider it appropriate to give regards to the long-term trend in margins as opposed to price in choosing a time horizon. However, we have considered the potential for changing circumstances to mean older data is less relevant. This is consistent with our selection of a fair margin value of

[34] If used to set the fair margin, we would escalate to 31 Dec 2023 terms (the midpoint of the Direction period), using the same approach as for our estimate (forecast inflation of 4.8% for the 2023 calendar year). This would increase the Wood Mackenzie fair margin estimate to $22.7/tonne.

		$18/tonne, consistent with the upward trend shown in figure 4.1.
Exclusion of 2022	Wood Mackenzie has proposed to exclude the most recent 15 months of the cycle (1 January 2022 to 31 March 2023) where coal prices are likely to have reached their near-term peak. Wood Mackenzie views the last 15 months of this cycle as being exceptionally unusual and warranting exclusion from the fair margin analysis.	We have retained 2022 data in our analysis. While we accept Wood Mackenzie's observation about 2022 prices, the margin time series (shown in figure 4.1) does not show a significant departure from historical averages. As a relatively high margin year, it also increases our fair margin calculation and mitigates against the possibility that older data is unreasonably dragging down our estimate.
Inflation	Wood Mackenzie conducted this analysis using costs and pricing data based on "real 2023 terms" (as at 1 Jan 2023), to help ensure the data being used is comparable and reflective of the business environment faced during the term of the Directions.	We conducted our analysis in real 2022 terms, so that our graphs and figures were not dependent on an inflation forecast. Our "real 2022" analysis is in dollars as at 31 Dec 2022, so this is functionally equivalent to the Wood Mackenzie approach (in dollars as at 1 Jan 2023). We consider that the final fair margin applied should be escalated to the end of December 2023 dollars to align with the period of the Directions. Our inflation forecast for 2023 is 4.8%.
Dollars per tonne	Wood Mackenzie considered it was more appropriate for a fair margin to be applied as a dollars per tonne metric rather than as a percentage of production costs. It considers a margin based on dollars per tonne terms is both easier to understand and apply and provides a much stronger incentive for producers to operate efficiently, in turn, likely saving on costs associated with the Directions.	We reached the same endpoint on application of a consistent dollars per tonne fair margin, though our reasoning was not based on the incentive effects mentioned by Wood Mackenzie. We shared the view that the dollars per tonne basis was simple, transparent and efficient. Our view was also that this was a more accurate way to state a consistent fair margin.

Notwithstanding the differences in some of the key points set out in the table above, based on our observations of Wood Mackenzie's analysis on margins,[35] the median margin would appear to be between $15–$20/tonne, which is relatively consistent with our calculations above.

The Wood Mackenzie report also made note of several other potential approaches to fair margin estimation, which are presented in Table 4.

Table 4 Other potential approaches noted by Wood Mackenzie

Category	Wood Mackenzie statements	AER consideration
Use of WACC	Mining companies typically have well-established investment frameworks, though the targeted rate of return can differ significantly between companies and over time.[36] Weighted average cost of capital (WACC) approaches were commonly used to set minimum expectations; but Wood Mackenzie noted these rate of return-based	This aligns with our consideration of these approaches, which do not fare well on criteria of simplicity, efficiency, or transparency.

[35] Wood Mackenzie, *NSW domestic coal pricing study, Prepared for the Australian Energy Regulator*, March 2023, p. 28, figure 21.

[36] Wood Mackenzie, *NSW domestic coal pricing study, Prepared for the Australian Energy Regulator*, March 2023, p. 26.

	methods would be more complex than the type of fair margin approach sought by the AER.	
Use of IRR	While WACC calculations are helpful, mining companies use a variety of alternative approaches when it comes to implementation.[37] This includes determining their own discount rate based on experience or an industry with similar perceived risk. Wood Mackenzie stated that of this family of approaches, based on its expert engagement with mines and investment banks, it would propose using an internal rate of return (IRR) approach with an approximately 15% real discount rate.	For clarity, the 15% real IRR quoted by Wood Mackenzie would not be applied as a percentage of production costs; it would be used together with detailed forecasts of future cashflows (in and out of the business) and an estimate of current investment (the capital base) to derive a margin. This complexity is why we have not proposed such a method. IRR estimates typically sit above the required rate of return. A recent RBA research article found support for a number of different reasons why this might be. One key reason was that internal hurdle rates were set well above the WACC to ration capital in the face of insufficient operational or managerial capacity.[38]
Use of 3-7% markup	Historically, domestic thermal coal was priced using a simple percentage markup over cash operating costs, with the markup between 3% and 7%.[39] Wood Mackenzie stated that this is an outdated practice, no longer in use, and that expected returns are now higher than this.	We note that the fair margin we are proposing ($18/tonne) provides a larger fair margin for all plausible cost ranges. For instance, if base production costs were $150/tonne, the historical practice would have set a margin between $4.5/tonne (at 3%) and $10.5/tonne (at 7%).

Estimates from financial accounts and quarterly production reports

Finally, we considered the extent to which our chosen implementation approach relies on the Wood Mackenzie dataset. In compiling the dataset, Wood Mackenzie uses its judgement to make a number of material decisions around the reporting basis and allocation approach. If the underlying dataset was not reliable, our overall approach would risk being inaccurate. This would not be detected in a comparison against the Wood Mackenzie public report findings, because they created the dataset.

Wood Mackenzie is a well-established data provider with demonstrated depth of expertise. AEMO commissions annual coal cost projections from Wood Mackenzie to inform its system forecasting and planning role.[40] In bilateral meetings with Coal Suppliers, many informed us that they subscribe to Wood Mackenzie's proprietary data.

Our understanding is that Wood Mackenzie's principal data source is publicly available quarterly production reports published by the different Coal Suppliers. We were able to consider these reports and verify a sample of key figures. This also demonstrated the advantage of using the Wood Mackenzie dataset, which benefits from its expert judgement and consistent allocation of revenue and costs across time and companies.

We also attempted to reconcile the Wood Mackenzie dataset to published statutory reporting (annual financial reports) published by Coal Suppliers. Overall, this was difficult to do at a level relevant to our analysis, because the reporting basis would not align with our targeted

37 Wood Mackenzie, *NSW domestic coal pricing study, Prepared for the Australian Energy Regulator*, March 2023, p. 26.

38 H. Edwards and K. Lane, Why are investment hurdle rates so sticky?, *RBA Bulletin*, December 2021. Available at https://www.rba.gov.au/publications/bulletin/2021/dec/why-are-investment-hurdle-rates-so-sticky.html, accessed 25 March 2023.

39 Wood Mackenzie, *NSW domestic coal pricing study, Prepared for the Australian Energy Regulator*, March 2023, p. 29.

40 For example, see Wood Mackenzie, *Coal cost projections: Approach to coal cost projections*, May 2021, available at https://aemo.com.au/en/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios

characteristics (i.e., NSW thermal coal). One example might be where a multinational company reports EBITDA-level figures for combined production of thermal coal from all countries. Another example is where a mining company presents its Australian coal production with details on costs and sales but does not disaggregate between domestic supply and export production.

Overall, we consider that the Wood Mackenzie dataset is an appropriate foundation for our fair margin analysis.

5 Price cap application process and confidentiality

5.1 Higher price cap application process

The process for Coal Suppliers to apply for a higher cap is set out below. The same process should be followed in the event that a change to the ministerial declarations necessitates a revised application.

1. The Coal Supplier submits to the NSW Office of Energy and Climate Change (OECC) an application using the AER's standard form at Attachment 1.
    - The Coal Supplier first contacts the OECC at the email coalmarketemergency@dpie.nsw.gov.au
    - The OECC will provide the Coal Supplier with login details for a secure file transfer site.
    - The Coal Supplier then securely uploads the application form and supporting information.
2. The OECC informs the Minister. If the Minister decides to ask the AER for its advice on the application, the AER will be provided access to the application and supporting information on the secure file transfer site.
3. Once we retrieve the Coal Supplier's application from the OECC through a secure file sharing system, we will download it and add it onto our secure document management system.
4. The AER assesses the application in line with this guidance note.
    - The AER may seek further information from the applicant.
    - The applicant must securely submit any requests for further information to the OECC using the same login details as previously established. The OECC will provide the AER with secure access to the further information.
    - We expect that the applicant will provide the further information within 5 business days, however this may vary depending on the scope and complexity of our request.
    - We expect our assessment will take approximately seven weeks (35 business days). However, our assessment may take longer depending on complexity and the timeliness of applicant's responses to our information requests.
        i. Please note: Many government departments and market agencies, including the AER, temporarily close offices around the Christmas/New Year holiday period. As a result, there will likely be a pause in the AER's processing of applications over this period. Applications received in the lead up to this period may face delays to the final outcome.[41]

[41] For example, applications referred to us by the NSW Minister from early November 2023 may not receive a final outcome until February 2024.

5. The AER securely transfers its assessment to the OECC, which provides the assessment to the Minister.

6. The Minister makes a decision on the Coal Supplier's application and the OECC informs the Coal Supplier.
    - If required, updated Directions are published (gazetted) with a revised Schedule 1 stating a changed price cap for the relevant mine.

5.2 Submitting confidential information

Coal Suppliers must make confidentiality claims in the following manner:

- specify in the filename whether it is "public" or "confidential"
- in confidential documents, highlight the specific confidential information in yellow shading
- provide reasons in support of the confidentiality claim.

The AER is committed to treating confidential information responsibly and in accordance with the law. The AER has an obligation, under section 44AAF of the *Competition and Consumer Act 2010 (Cth)* (the CCA), to take all reasonable measures to protect, from unauthorised use or disclosure, information that is:

- given to it in confidence in, or in connection with, the performance of its functions or the exercise of its powers; or
- obtained by compulsion in the exercise of its powers.

This obligation will apply to information provided to the AER under or in connection with its functions or powers under the *Energy Utilities Administration Act 1987* (the EUA Act).

Under the CCA, there are a number of situations where use or disclosure of this information is authorised. These include disclosure and use by AER staff in performing their functions, disclosure to the Commonwealth, disclosures required or permitted under state law (such as section 19 of Schedule 3 to the EUA Act, or section 41 of the EUA Act), and disclosures required or permitted under Commonwealth law.

The *Freedom of Information Act 1982 (Cth)* (FOI Act) will also apply to this information. Under the FOI Act, an agency may withhold access to a document if the document is exempt from release. Information on exemptions under the FOI Act can be found on the Office of the Australian Information Commissioner website: https://www.oaic.gov.au/freedom-of-information/foi-guidelines/part-5-exemptions.

Relevant NSW legislation (including the *Government Information (Public Access) Act 2009*) and other powers may also apply to the application and supporting information. For information on how the NSW government will manage and protect confidential information please contact the OECC.

Attachment 1 – Required form of application for Coal Suppliers

To apply for a change to the price cap, complete this form and provide required information, data and documents. Each question should be answered fully and, where possible, accompanied by documents that substantiate the response to the question. If a question is not relevant or where information is not available and cannot be reasonably estimated, please explain why. This is the form determined by us under section 8(1)(3)(a) of the Directions and applies to all applications. Where relevant, we request historical supporting information or actuals for the past 2 years and forecasts to at least the period ending 30 June 2024.

It is an offence to knowingly provide false or misleading information to the AER. Refer to section 137.1 of the *Criminal Code Act 1995*.

Instructions
Completing the application form 1. Complete Parts A, B and C of this form. 2. Attach any additional information or documents that are required or that the applicant considers are relevant to the application.
Submitting the application form and supporting material Submit the completed application form and supporting material via secure file transfer: • The Coal Supplier first contacts the NSW Office of Energy and Climate Change (OECC) at the email coalmarketemergency@dpie.nsw.gov.au • The OECC will provide the Coal Supplier with login details for a secure file transfer site. • The Coal Supplier then securely uploads the application form and supporting information.
PART A: Business structure and mine details
1. Provide a chart that sets out: a. the applicant's corporate structure, if the applicant is incorporated, and all related persons (as determined under section 4A of the *Competition and Consumer Act 2010 (Cth)*) and related entities (within the meaning of the *Corporations Act 2001*), or b. if the applicant is an incorporated or unincorporated joint venture, the participants in the joint venture and all related persons to and/or related entities to the participants in the joint venture. 2. Provide a brief description of the mine subject to this application. With regard to the chart provided in (1), identify the controlling entity or entities and any financial interests in the mine. 3. Provide supporting financial documents, such as the past two years of annual financial statements, to support the provision of historical financial information requested in part B.
PART B: Information required to assess a coal mine's production costs
1. Provide the following contract and volume information:

a. Total volume of coal produced, broken down by type and calorific value on a run-of-mine basis. Where washing is used to improve the quality of coal, we also require a breakdown of post-processing coal volumes, calorific value and yield percentage. Volumes should also distinguish:
   i. Thermal and non-thermal coal (if relevant)
   ii. Domestic and export (if relevant).
b. Details of any current or recently completed contracts (that is, in the last 2 years) with any of the generators covered in the Direction. This information should include the actual or contracted coal volumes dispatched (total and periodic dispatches), calorific values, and contracted price for the previous 2 years.

For the information requested below, include:

a. historical information for 2 years prior (2020–21 and 2021–22).
b. relevant supporting financial documents, contracts or other information to justify this historical information in (a).
c. estimated (or actual) values for the 2022–23 financial year.
d. a single forecast value for the period to 30 June 2024.
e. a set of assumptions and underlying methodology in estimating (c) and (d).

A checklist should be provided indicating whether information has been provided for each of (a) to (e) above for each piece of information we are requiring in Part B.

For the checklist above, indicate in the appropriate section where a set of information is relevant to more than one of the cost categories below (e.g. financial statements or a common methodology).

1. **Provide the following core cost information for domestic production of coal:**
   a. Direct mining costs
      i. Labour or contractor costs for extraction of coal
   b. Allocated overheads
      i. General labour or contractor expenses
      ii. Administrative expenses
      iii. Insurance costs
      iv. Any other corporate overhead costs (these should also be itemised by category)
   c. Coal processing costs
   d. Transportation costs
   e. Royalties
   f. Optional: Any other core costs unaccounted for in (a)–(e)
2. **Provide the following non-core cost information:**
   a. Take-or-pay costs
      i. This should clearly identify the take-or-pay position under contract before and after the impact of the Direction.
      ii. Clear documentation detailing the strategies and steps taken to minimise the impact of take-or-pay costs, or, if no action was taken, justification for why this has not occurred.
   b. Stockpiling and handling costs
      i. This should clearly identify the incremental stockpiling and/or handling cost requirements directly as a result of the Directions.
   c. Rehabilitation costs
      i. This should clearly identify the incremental rehabilitation cost requirements directly as a result of the Directions.
   d. Optional: Any other non-core costs unaccounted for in (a)-(c)

3. **Provide a general cost allocation methodology for any costs where the direct dollars per tonne cannot be calculated clearly**
    a. If there are multiple cost allocation approaches employed, clearly identify which costs have been calculated using each cost allocation methodology.
4. **Provide the following additional information:**
    a. Revenue and average price, with split between
        i. Thermal and non-thermal coal (if relevant)
        ii. Domestic and export (if relevant)
    b. Link production forecasts to the volumes nominated in mine contracting, rail and port contracts.

List the supporting documents that are submitted as part of the application and provide any further information the applicant wishes to be considered in relation to the application.

Any financial information and cost estimates must be submitted in the following format:

- Australian dollar terms, including any exchange rate assumptions used in converting to AUD.
- On Australian financial year basis (year-end 30 June). Where business reporting is normally done on calendar year (or other year-end basis), clearly indicate how data was allocated back to a 30 June year-end basis.
- For historical information, report any relevant figures in $nominal. Historical data should also indicate the time-of-year dollar terms it is in (e.g. as at 31 December 2022). If forecast cost estimates are made using historical information, include the underlying CPI escalator and any forecast inflation assumptions.
- For forecast information, report any relevant figures in 2022 end of year $real terms. Also include inflation estimates in bringing forecast information back to real dollar terms where relevant.

PART C: Certification of application

Please include the following with your application:

I certify that:

1. I am the Managing Director, Chief Executive Officer, Director or Company Secretary of the applicant as shown in Part A of the application.
2. After making all appropriate enquiries and checks, to my knowledge and belief the information given in this application is true, correct and complete, and all information are identified as such and are the best forecast of the underlying facts.
3. Complete copies of all documents provided with this application have been provided and these documents may be relied on as true and correct business records of the applicant.
4. The documents and information provided in this form can be shared with the Australian Energy Regulator and its staff, for the purposes of assessing and providing advice to the NSW Minister for Energy on the cost of production and fair margin.

I understand it is an offence to provide false or misleading information (or omitting to provide relevant information) to a Commonwealth entity under section 137.1 of the *Criminal Code Act 1995*.

Please sign and date the document, add your full name, position and address.

Glossary

Term	Definition
AER	Australian Energy Regulator
CCA	*Competition and Consumer Act 2010 (Cth)*
the cap	The price cap of $125 per metric tonne as per the Directions
Coal Supplier	Coal suppliers are specified under Schedule 1 of the *Coal Market Price Emergency (Directions for Coal Mines) Notice 2023*
Depreciation	Return of capital
Directions for Power Stations	*Coal Market Price Emergency (Directions for Power Stations) Notice 2023*
the Directions	*Coal Market Price Emergency (Directions for Coal Mines) Notice 2023*
EBITDA	earnings before interest, taxes, depreciation, and amortisation
EUA Act	*Energy and Utilities Administration Act (NSW) 1987*
FOI Act	*Freedom of Information Act 1982 (Cth)*
IRR	internal rate of return
kcal	kilocalories
kg	kilogram
Minister	NSW Minister for Energy
NEL	National Electricity Law
NER	National Electricity Rules
NSW	New South Wales
OECC	Office of Energy and Climate Change
Power Station	Power stations are specified under section 5 of the *Coal Market Price Emergency (Directions for Power Stations) Notice 2023*
WACC	Weighted average cost of capital