APPENDIX T - GREENHOUSE GAS ASSESSMENT AND ABATEMENT PLAN

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Isaac Downs Extension Project Greenhouse Gas Assessment and Abatement Plan

Prepared for:

Stanmore ID Extension Pty Ltd

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4.0

Prepared by:

Katestone Environmental Australia Pty Ltd
ABN 21 680 559 095
Level 4, 154 Melbourne Street, South Brisbane
Queensland, 4101, Australia

www.katestone.global
admin@katestone.com.au
Ph +61 7 3369 3699

katestone
www.katestone.global

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Prepared by:	Alex Scholten and Carlo Bunin
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Glossary

Term	Definition
°	degrees
°C	degrees Celsius
C	carbon
GJ	gigajoule
ha	hectares
kg	kilograms
kL	kilolitres
km	kilometres
m	metres
m^2	square metres
m^3	cubic metres
Mt	million tonnes
Mt CO_2-e	million tonnes of carbon dioxide equivalent
t	tonnes
t c	tonnes of carbon
t CO_2-e	tonnes of carbon dioxide equivalent
Nomenclature	**Definition**
CH_4	methane
CO_2	carbon dioxide
CO_2-e	carbon dioxide equivalent
Abbreviation	**Definition**
ACCU	Australian Carbon Credit Unit
CC Act	*Climate Change Act 2022*
CCCA Act	*Climate Change (Consequential Amendments) Act 2022*
CEJ Act	*Clean Economy Jobs Act 2024*
CER	Clean Energy Regulator
CRL	Commercial Readiness Level
CSG	Coal seam gas
DBCT	Dalrymple Bay Coal Terminal
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DESI	Department of Environment, Science and Innovation
DETSI	Department of Environment, Tourism, Science and Innovation
EA	Environmental Authority
EF	Emission factor
EI	Emissions intensity
EP Act	*Environmental Protection Act 1994*
FullCAM	Full Carbon Accounting Model
GHG	Greenhouse gases
GHG Guideline	*Guideline Greenhouse gas emissions ESR/2024/6819*
GWP	Global warming potential
IPCC	Intergovernmental Panel on Climate Change
LULUCF	Land use, land use change and forestry
LGA	Local government area
LOM	Life of Mine
ML	Mining lease
NDC	Nationally Determined Contribution
NEM	National Electricity Market
NGER	National Greenhouse and Energy Reporting
NGER Act	*National Greenhouse and Energy Reporting Act 2007*

Term	Definition
NGER Determination	*National Greenhouse and Energy Reporting (Measurement) Determination 2008*
PBOGS	Petroleum based oils and greases
PCI	Pulverised coal injection
PL	Petroleum Lease
PPA	Power purchase agreement
QLD	Queensland
ROM	Run-of-mine
Safeguard Mechanism	*Safeguard Mechanism (Crediting) Amendment Act 2023*
Scope 3 Standard	Greenhouse Gas Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard
SMC	Safeguard Mechanism Credits
Stationary fuel	Fuel used on site for plant equipment, generators and permanent site vehicles
TRL	Technical Readiness Level
UNFCCC	United Nations Framework Convention on Climate Change

EXECUTIVE SUMMARY

Katestone Environmental Australia Pty Ltd (Katestone) was commissioned by Stanmore ID Extension Pty Ltd (ID Extension), a subsidiary of Stanmore Resources Ltd (Stanmore), to conduct a Greenhouse Gas (GHG) assessment for the proposed Isaac Downs Extension (IDE) Project (the Project). The Project will be integrated into the Isaac Plains Complex (IPC), comprising Isaac Downs Mine (IDM) and Isaac Plains Mine (IPM). The Project will extend the life of mining activities at IDM in the Bowen Basin, approximately 15 km southeast of Moranbah.

The Project will comprise of an open cut coal mine pit and associated infrastructure, primarily mining metallurgical (steel making) coal. Approximately 46 million tonnes (Mt) of run of mine (ROM) coal will be mined over 15 years starting from 2029, with approximately 2 – 4.5 million tonnes (mined) per annum (Mtpa).

The Project requires an environmental impact statement (EIS) that will be assessed by the Queensland and Commonwealth governments. This GHG assessment has been completed in accordance with the requirements of the terms of reference (TOR) for the EIS and has been informed by Project information supplied by Stanmore, including Stanmore's in-house resources for the management of GHG.

The assessment shows the total life of mine (LOM) emissions are estimated to be 82.45 Mt CO_2-e.

Of this 26 year total:

- Scope 1 emissions contribute 1.27 Mt CO_2-e with average annual emissions of 0.049 Mt CO_2-e
    - Stationary diesel combustion and fugitive methane emissions are the largest contributors to total LOM Scope 1 emissions at 752,200 t CO_2-e and 377,066 t CO_2-e respectively
- Scope 2 emissions contribute 0.18 Mt CO_2-e, with average annual emissions of 0.0070 Mt CO_2-e
- Scope 3 emissions contribute 81.00 Mt CO_2-e with average annual emissions of 3.12 Mt CO_2-e with:
    - Emissions within Australia of 0.89 Mt CO_2-e and outside Australia of 80.10 Mt CO_2-e

The Project's combined total Scope 1 and 2 emissions are estimated to represent 0.087% and 0.020% of the remaining Queensland and Australian carbon budgets, respectively, under a pathway consistent with limiting warming to 1.5°C. Under a 2°C pathway, the corresponding contributions are 0.052% and 0.012%. The Project's total LOM emissions (Scopes 1, 2 and 3) are estimated to represent 0.016% of the remaining global carbon budget for 1.5°C, and 0.009% for 2°C.

Stanmore acknowledge Australia's commitment to net zero emissions by 2050 and will continue aligning its decarbonisation efforts with the Australian Government's commitments to contribute to the goal of the Paris Agreement. Consequently, Stanmore is developing a decarbonisation strategy and is investing in decarbonisation projects that include capturing coal seam methane and converting it to electricity at its South Walker Creek Mine. Solar projects are also being evaluated at IPC and other Stanmore facilities and connection applications have commenced. These projects will reduce Scope 1 and Scope 2 emissions and may result in Safeguard Mechanism Credits (SMC) that can be used to offset emissions from other Stanmore facilities.

The Project will produce Scope 1 and Scope 2 emissions and based upon the Queensland Greenhouse Gas Emissions guideline ESR/2024/6819 is a medium to high emitter (greater than 25 000 t $CO_{2\text{-eq/year}}$). The option to avoid emissions production through not progressing with the Project is considered economically undesirable. Stanmore intends to meet the Safeguard Mechanism reduction requirements for the IPC facility, inclusive of the Project, through the following activities to avoid, reduce, substitute, and/or offset emissions where practicable and cost-effective:

Avoid

- Minimising unnecessary clearance of vegetation to minimise emissions during land clearing activities

Reduce

- Mobile and stationary plant emissions are reduced from the base case through:
  - Optimisation of mine layout and operations
  - Optimisation of vehicles and processes for energy efficiency
  - Replacement of diesel with premium diesel
- Pre-drainage of CSG and flaring or combustion to produce electricity if technically and economically feasible
- Staff are engaged in energy efficiency and emissions reduction

Substitute

- Use of an electrically powered dragline as preferred option for overburden removal, thereby reducing diesel consumption for equipment that would otherwise be used for overburden removal
- Emissions due to electricity usage will be minimised through:
  - Purchase of renewably generated electricity through a Power Purchase Agreement where this is cost effective
  - Onsite renewable electricity generation or through electricity generation by combusting drained CSG, where technically and economically feasible

Offset

- SMC will be surrendered against Project emissions above baseline where this is the most economic use of them
- Purchase and surrender of Australian Carbon Credit Units (ACCU) generated in Queensland where feasible and cost-effective, and in the rest of Australia

The measures that Stanmore are undertaking to reduce diesel use through efficiency measures will be reflected in a reduction in both scope 1 and scope 3 emissions. Scope 3 GHG emissions associated with the transport of product coal, are expected to reduce as contracted companies meet their published emission reduction goals.

Stanmore commits to a process of continuous improvement informed by engaged staff, monitoring, evaluation, and research. They will continue to build on its current commitments including electric dragline, use of premium diesel, replace light vehicles with battery electric vehicles (BEV) or hybrid, and solar powered crib hut. Potentially feasible projects requiring further assessment include electric excavator, dual fuel technologies in haulage fleet and BEV haul trucks. New and emerging technologies will be considered as they evolve.

Stanmore will report on its emissions and emissions reduction targets through the annual NGER and Safeguard Mechanism process and through Stanmore‘s annual sustainability report.

1. INTRODUCTION

Katestone Environmental Australia Pty Ltd (Katestone) was commissioned by Stanmore ID Extension Pty Ltd (ID Extension), a wholly owned subsidiary of Stanmore Resources Ltd (Stanmore), to conduct a Greenhouse Gas (GHG) assessment for the proposed Isaac Downs Extension (IDE) Project (the Project). The Project will extend the life of mining operations at the Isaac Plains Complex (IPC), currently comprising Isaac Downs Mine (IDM) and Isaac Plains Mine (IPM), approximately 15 km southeast of Moranbah, in the Bowen Basin. Mining of ROM (run of mine) coal at IDM is expected to ramp down between 2026 and 2028.

The Project will be comprised of an open cut coal mine pit and associated infrastructure and will primarily mine metallurgical (steel making) coal. Approximately 46 million tonnes (Mt) of run of mine (ROM) coal will be mined over 15 years, with approximately 2 – 4.5 million tonnes (mined) per annum (Mtpa). Project construction is intended to commence late 2027 / early 2028 with ROM coal extraction commencing in 2029.

The Project adjoins IDM and will be integrated into IPC, with shared mine infrastructure area (MIA) at IDM, including connecting infrastructure such as water management infrastructure and power supply, and ROM coal will be washed at the IPM coal handling and preparation plant (CHPP).

The open cut mining methods for the Project will include:

- clearing of vegetation, stripping, and stockpiling of topsoil
- drilling and blasting of pre-strip overburden
- removing the pre-strip overburden using mining equipment at IDM being a dragline and / or truck and shovel fleets and / or dozers
- drilling and blasting of overburden
- drilling and blasting of pit floor for geotechnical stability to allow for in-pit dumping
- overburden removal using the existing dragline at IDM and / or truck and shovel fleets
- coal mining using excavators
- formation of out of pit and in-pit overburden dumps as mining progresses
- progressive rehabilitation of overburden dump areas.

Power for the dragline will be supplied via connections to IDM's existing power supply.

The Project has been determined to be a controlled action (EPBC2025/10183) under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). ID Extension will prepare an environmental impact statement (EIS) under the *Environment Protection Act 1994* that will be assessed by the Queensland and Commonwealth governments.

The GHG assessment requirements are provided in the Terms of Reference (section 2).

2. TERMS OF REFERENCE

The final Terms of Reference (ToR) for the Project have the requirements outlined in Table 1.

Table 1 Sections of the GHG assessment addressing the requirements of the ToR

Requirement		Section
9.5	**To assess emissions to demonstrate that the project can meet the environmental objectives and performance outcomes in Schedule 8 of the EP Reg and meet the department's Guideline—Greenhouse gas emissions (ESR/2024/6819- version 1.02) (DETSI 2026)[1]. Broadly this guideline requires:**	
	a) **Details of likely direct (Scope 1) and indirect (Scope 2) emissions to inform:** i. **assessment against regulatory requirements and the standard criteria; and considerations under the *Human Rights Act 2019* by the delegate of the administering authority.**	Section 5 Table 7 Section 7.2
	b) **Details of the mitigation and management measures/practices and how they align with the GHG abatement hierarchy.**	Section 6.6 and Table 14
	c) **A risk assessment that outlines the scale of expected GHG emissions from the project and how it is expected to contribute to climate change impacts on Queensland's environmental values.**	Section 7
9.6	**To provide information regarding emissions and energy production and consumption consistent with the Commonwealth *National Greenhouse and Energy Reporting Act 2007* (NGER Act) and subordinate legislation including the methodology, emissions factors, and calculations used.**	Section 4.3
9.7	**Undertake an assessment of emissions, including:**	
	a) **An estimate of annual and cumulative Scope 1 and Scope 2 CO_2 equivalent emissions (abated and unabated) over the life of the project.**	Section 5.2 and Table 9
	b) **An estimate of annual and cumulative Scope 3 emissions over the life of the project, identifying whether these occur domestically or internationally and whether they are expected to be generated in a country that is a signatory to the Paris Agreement or has other equivalent policies.**	Section 5.3 and Table 10
	c) **Where relevant, include land-clearing emission estimates using the Full Carbon Accounting Model (FullCAM) in accordance with the ACCU scheme methods and the FullCAM guideline with all assumptions and inputs provided.**	Sections 4.3.1.3, 5.2 and Table 8
9.8	**Justify how the project will influence Queensland's GHG emission reduction targets for the life of the project by:**	
	a) **Demonstrating support for the legislated targets in the *Clean Economy Jobs Act 2024*.**	Section 7.2
	b) **Meeting the requirements of the NGER Act and, where triggered, the emission reduction targets and trajectory under the commonwealth's Safeguard Mechanism.**	
9.9	**Provide the following information:**	

[1] Note that TOR refer to GHG guideline 2024, this was updated by DETSI in January 2026 however there are no material impacts of the update to this assessment.

	a)	**Scope 1 and 2 emissions reduction targets and trajectory over the life of the project. For Safeguard facilities, provide the estimated baselines representing the Scope 1 emissions reduction trajectory.**	Section 6.5 and Table 12
	b)	**Planned ongoing mitigation and management measures to progressively reduce emissions, stated as specific, measurable, achievable, realistic, and time-bound (SMART principals).**	Section 6.6, Table 13 and Table 14
	c)	**The estimated volume of carbon offsets required to achieve reduction targets and how offset requirements under the department's Guideline and/or the Commonwealth Safeguard Mechanism will be met if applicable.**	
9.10	**In addition to addressing the requirements of the department's Guideline—Greenhouse gas emissions (ESR/2024/6819), the EIS must also:**		
	a)	**Describe and compare feasible project alternatives (conceptual, technological, locality, configuration, scale or component changes) considered to avoid or reduce the project's emissions.**	Sections 6.5 and 6.10
	b)	**Compare and detail preferred GHG controls and energy consumption measures against best practice and leading international environmental management, including developing technologies.**	Sections 6.8, 6.10, 6.11 and Table 14
	c)	**Describe assumptions and data inputs applied to develop emissions estimates and the emissions reduction targets. For Safeguard facilities, calculate baselines using methodology in the National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015 (Safeguard rule).**	Section 4
	d)	**Detail processes for continuous improvement, including identification of new technologies, management practices and personnel training over the life of the project.**	Sections 6.10 and 6.11
	e)	**For coal mining projects, investigate methane drainage feasibility. If not feasible, the feasibility assessment must be reviewed and endorsed by an appropriately qualified person.**	Section 4.3.1.1
	f)	**Demonstrate that measures have been factored into the economic feasibility of the project**	Section 6 Table 12
	g)	**Identify any voluntary initiatives or research to reduce the lifecycle and embodied energy carbon intensity of the project's processes or products.**	Section 6.7
	h)	**Identify opportunities to reduce Scope 3 emissions and detail measurable commitments where appropriate.**	
	i)	**Compare expected cumulative project GHG emissions with the remaining global, national and state emission budgets[2], considering all Scope 3 emissions at the relevant scale.**	Section 7.1 and Table 15
	j)	**Where offsets are the only remaining option for abatement, develop a comprehensive carbon offsets management plan, including market supply considerations.**	Section 6.6.4
	k)	**Develop an annual reporting program demonstrating progress towards the project's emissions reduction targets. Where facilities are already reporting emissions under another framework, refer to that reporting.**	Section 6.9

[2] Remaining global carbon budgets should be based on the latest Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) and the latest Global Carbon Budget updates (2025, Friedlingstein et al), using 50% probability budgets for limiting warming to 1.5°C and 2°C and adjusting these to the project's commencement year. National and state budgets should also align with the project's commencement year and may be derived either by allocating the global budget to Australia and Queensland (e.g. per-capita or emissions-share approaches) or by estimating budgets from historical emissions and legislated targets, applying a linear reduction pathway between those targets. All assumptions and adjustment methods should be clearly stated.

3. REGULATORY ENVIRONMENT

3.1 International Agreements

3.1.1 Paris Agreement

The Australian Government signed the legally binding Paris Agreement (UNFCCC, 2015) to take actions to keep global warming to ‘well below’ 2°C above pre-industrial levels and pursue efforts to limit warming to 1.5°C above pre-industrial levels.

The current Australian target (Nationally Determined Contribution) is to reduce emissions to 43% below 2005 levels by 2030, and 62 – 70% by 2035, including land use, land use change and forestry (LULUCF). The legislated target is to have net zero GHG emissions by 2050.

3.2 Legislation and Regulation

3.2.1 *Climate Change Act 2022* (Cwlth)

The *Climate Change Act 2022* (CC Act) provides the legislative framework to implement Australia’s net-zero commitments and codifies Australia’s 2030, 2035, and 2050 net GHG emissions reductions targets under the Paris Agreement.

3.2.2 *Climate Change (Consequential Amendments) Act 2022* (Cwlth)

The *Climate Change (Consequential Amendments) Act 2022* (CCCA Act) embeds the GHG emissions reduction targets into fourteen Commonwealth acts, including the *Clean Energy Regulator Act 2011*, *Infrastructure Australia Act 2008*, *National Greenhouse and Energy Reporting Act 2007*, and the *Renewable Energy (Electricity) Act 2000*.

3.2.3 *National Greenhouse and Energy Reporting Act 2007* (Cwlth)

The *National Greenhouse and Energy Reporting Act 2007* (NGER Act) established a national framework for corporations to report GHG emissions and energy consumption.

Under the National Greenhouse and Energy Reporting (NGER) scheme, corporations or facilities must register and report if they meet one or more of the following thresholds in a financial year:

- 25,000 tonnes or more of carbon dioxide equivalent (CO_2-e) emissions (scope 1 and scope 2),
- production of 100 terajoules (TJ) or more of energy, or
- consumption of 100 TJ or more of energy.

These entities are required to report on their Scope 1 and Scope 2 emissions. Scope 3 emissions are not included in NGER reporting due to the potential for double counting.

3.2.4 *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (Cwlth)

The *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (NGER Determination) provides methods, criteria, and measurement standards for calculating greenhouse gas emissions and energy data under the NGER Act. It covers Scope 1 and Scope 2 emissions and energy production and consumption.

3.2.5 *Safeguard Mechanism (Crediting) Amendment Act 2023* (Cwlth)

The *Safeguard Mechanism (Crediting) Amendment Act 2023* (Cwlth) (Safeguard Mechanism) provides a framework for Australia's largest emitters to measure, report and manage their emissions and is administered through the NGER scheme. It does this by requiring large facilities, whose net emissions exceed the Safeguard threshold of 100,000 tCO_2-e per year, to keep their emissions at or below an emissions baseline determined by the Safeguard Mechanism under the Clean Energy Regulator (CER). The CER is the government body responsible for accelerating carbon abatement for Australia through the administration of the National Greenhouse and Energy Reporting scheme, Renewable Energy Target, and the Emissions Reduction Fund.

3.2.6 *Clean Economy Jobs Act 2024 (Qld)*

The *Clean Economy Jobs Act 2024* (CEJ Act) establishes the following emissions reduction targets:

- by 30 June 2030, net greenhouse gas emissions in Queensland are reduced to an amount that is at least 30% below the net greenhouse gas emissions in Queensland for 2005
- by 30 June 2035, net greenhouse gas emissions in Queensland are reduced to an amount that is at least 75% below the net greenhouse gas emissions in Queensland for 2005
- by 30 June 2050, net greenhouse gas emissions in Queensland are reduced to zero (Queensland Treasury, 2026).

3.2.7 Energy (Infrastructure Facilitation) Act 2024 (Qld)

The *Energy Roadmap Amendment Act 2025* repealed the *Energy (Renewable Transformation and Jobs) Act 2024*, replacing it with the *Energy (Infrastructure Facilitation) Act 2024* (Energy Act). The Energy Act aims to ensure a safe, secure, and affordable electricity supply by facilitating the coordinated development of energy infrastructure, including transmission, storage, and generation. It removed fixed renewable energy targets and establishes Regional Energy Hubs.

3.2.8 Environmental Protection Act 1994 (Qld)

The *Environmental Protection Act 1994* (EP Act) seeks to protect Queensland's environment while allowing for development that improves the total quality of life, both now and in the future, in a way that maintains the ecological processes on which life depends.

The EP Act does not explicitly regulate the emission of GHG. However:

- Regarding air emissions, a contaminant can be a gas (11(a))
- GHG emissions may constitute an environmental harm (14(1)(2)), i.e., "… any adverse effect, or potential adverse effect (whether temporary or permanent and of whatever magnitude, duration or frequency) on an environmental value …" "whether the harm is a direct or indirect result of the activity; or whether the harm results from the activity alone or from the combined effects of the activity and other activities or factors".

3.3 Policy and Guidelines

3.3.1 Guideline Greenhouse gas emissions

The *Guideline Greenhouse gas emissions ESR/2024/6819* (GHG Guideline) describes requirements under the EP Act and provides information about how to meet these requirements in relation to GHG emissions for new and amended environmental authority (EA) applications and EISs.

The GHG Guideline sets out the minimum expectations for GHG emissions information to be provided with applications and supports rigorous, defensible, and transparent decision making in relation to these emissions. The required information includes:

- An inventory of expected GHG emissions resulting from the Project including the stage at which the emissions will occur and a breakdown by source
- An estimate of projected Scope 1 and Scope 2 CO_2-e emissions over the life of the project, including an unabated and abated emissions scenario
- An estimate of annual Scope 3 emissions and total Scope 3 emissions over the life of the Project
- A description of the method used for estimating GHG emissions
- A GHG abatement (decarbonisation) plan in alignment with recommendations made in Appendix A of the GHG Guideline
- A description of risks and the likely magnitude of impacts on environmental values resulting from the Project, including qualitatively describing the impacts of climate change on environmental values and the likely magnitude of such impacts based on the relative scale of the Project's net GHG emissions.

The GHG Guideline identifies expected GHG emission rates for activities as:

- **Low emitters** if expected annual GHG emissions are less than 25,000 t CO_2-e.
- **Medium to high emitters** if expected annual GHG emissions are 25,000 t CO_2-e or more at any time during the life of the project.

3.3.2 Corporate Value Chain (Scope 3) Accounting and Reporting Standard

The Greenhouse Gas Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard (Scope 3 Standard) (GHG Protocol, 2011) is the only internationally accepted method for Scope 3 emissions accounting and is applied here.

Scope 3 emissions refer to all indirect emissions occurring in the value chain of a reporting company, including upstream and downstream emissions, that are not included in the reporting company's Scope 1 and 2 inventory. Examples of Scope 3 emissions include emissions resulting from the production and transport of purchased goods, processing and use of sold products, and purchased services such as fuel-intensive activities or transportation.

Scope 3 emissions may be 'double-counted', when two companies account for the same emissions – this is recognised as a beneficial scenario because each company may have different and mutually exclusive opportunities to influence the sources of emissions. While a reporting company has no direct control over its Scope 3 emissions, it may exert influence over its Scope 3 inventory through strategic partnerships, policy-setting, and procurement decisions.

4. METHOD

4.1 Definitions of Scope 1, Scope 2 and Scope 3

GHG emissions are classified into three Scopes for monitoring, reporting, and management purposes. In Australia, these are defined in the NGER Act as:

- Scope 1. GHG emissions released to the atmosphere as a direct result of an activity or series of activities that are controlled by a company, and which are reported at a facility level. This would include emissions from combustion of diesel during construction or operation of the Project. These direct emissions are reported annually if the emissions exceed a legislated threshold (section 3.2.3).
- Scope 2. GHG emissions released to the atmosphere because of the generation of electricity that has been purchased by a company for use at a facility such as the Project. These are considered indirect emissions and are reported annually if the facility exceeds a legislated threshold (section 3.2.3).
- Scope 3. GHG emissions released to the atmosphere upstream or downstream in an organisation's supply or value chain. These indirect emissions are not reported under the NGER Act as they are another company or organisation's Scope 1 or Scope 2 emissions (section 3.3.2). This assessment considers the Scope 3 emissions from:
    - Purchased goods and services and capital goods,
    - Upstream production and transportation (well-to-pump) of diesel, and petroleum-based oils and greases (PBOGS)
    - Upstream production of electricity
    - Upstream transportation of diesel, explosives and materials to site required during operations
    - Downstream transportation and processing of waste generated in operations,
    - Business travel and employee commuting,
    - Downstream by rail (within Australia) and shipping (outside Australia), and
    - Processing / use of product coal

The purpose of monitoring and reporting GHG emissions is threefold:

- Allow Queensland and Australian governments to determine an annual inventory of GHG emissions against international agreements and legislated emissions reduction targets.
- Allow a company or organisation to manage or offset its Scope 1 and Scope 2 emissions to meet corporate or regulatory targets.
- Allow a company or organisation to influence Scope 3 emissions reduction through procurement or supply decisions.

4.2 Project activities that cause GHG emissions

Project activities that will lead to GHG emissions are presented in Table 2. These are differentiated by their scope and the Project phase in which they occur.

Table 2 Project activities that result in GHG emissions

Phase	Scope 1 and Scope 2	Scope 3
Operation	Diesel combustion by mine plant Diesel combusted in explosives Diesel combustion for generation of electricity Fugitive emissions from mining of coal Combustion of fugitive methane through flaring (where applicable) Electricity usage for the dragline and amenities Vegetation clearing Combustion of petroleum-based oils and greases	Diesel combustion for transport of materials and products Upstream fuel extraction and processing Workforce commute and business related road and air travel Handling of Project waste End use of sold product coal Upstream production of electricity consumed. Production of purchased goods and services, and capital goods
Decommissioning	Diesel combustion for rehabilitation activities Electricity usage	Upstream fuel extraction and processing

4.3 Calculation of GHG emissions

Projected annual Scope 1, Scope 2, and Scope 3 GHG emissions for the Project during construction and operation are calculated from projected activity data provided by Stanmore by applying the methods, fuel consumption and emissions factors described in the following resources:

- NGER Determination
- The National Greenhouse Accounts Factors (to date)
- The Greenhouse Gas Protocol (WRI/WBCSD, 2004)

4.3.1 Scope 1 and Scope 2

Scope 1 and Scope 2 emissions (t CO_2-e) are calculated with Method 1, as outlined in the NGER Determination.

The formulae are:

Scope 1: $$\frac{\mathbf{Q \times ECF \times EF}}{\mathbf{1000}}$$

Scope 2: $$\frac{\mathbf{Q \times EF}}{\mathbf{1000}}$$

where Q is the quantity of the emission source (e.g., with units kilolitres or kilowatts, kL, kWh), ECF is the energy content factor of the emission source (e.g., with units GJ/kL) (Table 3), EF is the emission factor that describes the total amount of equivalent carbon dioxide emissions associated with the emission source (i.e., with units kg CO_2-e/GJ) (Table 3), and the 1000 returns the correct units for the emissions (Table 3).

Table 3 Energy contents and emissions factors used in Scope 1 and Scope 2 calculations

Emission source	Energy content	Units	Emission factor		
			Scope 1	Scope 2	Units
Diesel (transport) [1]	38.6	GJ/kL	70.4	-	kg CO_2-e/GJ
Diesel (stationary) [1]	38.6	GJ/kL	70.2	-	kg CO_2-e/GJ
Land Clearing - Eucalyptus woodland [2]	-	-	51.35	-	t C / ha
Land Clearing - Eucalyptus open woodland [2]	-	-	48.81	-	t C / ha
Land Clearing - Acacia Forest and woodlands [2]	-	-	48.53	-	t C / ha
Land Clearing – Hummock shrubland [2]	-	-	51.82	-	t C / ha
Electricity usage [1]	-	-	-	0.67	kg CO_2-e/kWh
Petroleum based oils (other than petroleum-based oil used as fuel) [1]	38.8	GJ/kL	13.9	-	kg CO_2-e/GJ
Petroleum based greases [1]	38.8	GJ/kL	3.5	-	kg CO_2-e/GJ

[1] (DCCEEW, 2025)
[2] Full Carbon Accounting Model (FullCAM) (Richards, 2001)

4.3.1.1 Scope 1 fugitive emissions resulting from the extraction of coal

Fugitive GHG emissions resulting from the extraction of coal have been estimated in alignment with Method 2 as per Subdivision 3.2.3.2, Subsection 3.21 of the NGER Measurement Determination. The formula for Method 2 is:

$$E_j = y_j \times E_z(S_{j,z})$$

Where:

E_j is the fugitive emissions of gas type (*j*) that result from the extraction of coal from the mine during the year, measured in CO_2-e tonnes

y_j is the factor for converting a quantity of gas type (***j***) from cubic metres (m^3) at standard conditions of pressure and temperature to CO_2-e tonnes, as follows:

for methane : $6.784 \times 10^{-4} \times GWP_{methane}$.

for carbon dioxide: 1.861×10^{-3}.

$E_z(S_{j,z})$ is the total of gas type (*j*) in all gas bearing strata (z) under the extraction area of the mine during the year, measured in cubic metres, where the gas in each strata is estimated under section 3.22 of the NGER determination.

The method requires each gas in a gas bearing stratum (z) to be analysed in accordance with the requirements in sections 3.24, 3.25 and 3.25A of the NGER determination.

A coal seam gas report for the IDE was completed in November 2025 (Thomson and Thomson, 2025a, Appendix B). The result is a calculated gas content and gas composition for zoned depth intervals that then can be used to determine a CO_2-e value for seams that are mined from the corresponding zone. The respective CO_2-e values multiplied by the *in-situ* tonnes of run of the mine (ROM) coal of a particular zone determines emissions. Emissions originating from within 20m of the final pit floor horizon are assigned a release factor of 50% for gas bearing strata.

ROM coal projections by seam depth were estimated by Stanmore using the total coal mined from each seam across production years (2029 to 2043). The quantity of coal projected to be extracted from each depth was multiplied by the depth-dependent CO_2-e emission factor produced in the fugitive emissions report (table 2, Thomson and Thomson, 2025a and Thomson and Thomson, 2025b). The results of this approach have been included in this assessment to estimate fugitive emissions for the Project.

This calculation approach excludes gas bearing strata located beneath the final pit floor, as these will be progressively excavated over the remaining life of mine. At the completion of mining, there will be no strata classified as gas bearing affecting fugitive emission assessment located within 20m of the final pit floor (see sections 3.1 and 3.2 of Appendix B Thomson and Thomson, 2025a).

4.3.1.2 Scope 1 emissions from diesel used in explosives

The ANFO explosives used contain approximately 6% diesel by mass. The quantity of diesel combusted was calculated by multiplying the total explosives usage by 0.06. Emissions were then estimated using Method 1 as described in the NGER Determination and in section 4.3.1.

4.3.1.3 Scope 1 emissions from vegetation clearance

The Full Carbon Accounting Model (FullCAM) (Richards, 2001) is used to assess the carbon stock (tonnes carbon per hectare (t C / ha)) of vegetation within the proposed areas for land clearing resulting from the Project. FullCAM estimates the carbon stock change in ecosystems at a grid scale of 25 m x 25 m including:

- above and belowground biomass
- standing and decomposing debris
- soil carbon resulting from land use and management activities.

The carbon stock is multiplied by an emissions factor to give the t CO_2-e that would be emitted if all the carbon was converted to carbon dioxide at a single point in time.

The vegetation to be cleared was identified by regional ecosystem (RE) type. RE were matched to the applicable FullCAM vegetation type (Table 4). Areas identified as non-remnant or grassland were excluded from assessment.

Emissions were calculated by running FullCAM simulations of 100% clearing for each FullCAM vegetation type. FullCAM returns the total tonnes of carbon per hectare (t C / ha) for the vegetation type (Table 2). The t C values are converted to t CO_2-e by dividing the ratio of the molecular weight of carbon dioxide to that of carbon (44/12). The t CO_2-e is then multiplied by the vegetation type area (in hectares) cleared. Land clearing is assumed and modelled as occurring entirely in Year 2, with all pre-clearing carbon stock accounted as emitted in the same reporting year.

Table 4 Mapping of Regional Ecosystems to FullCAM Vegetation Types and Areas to be Cleared

Regional Ecosystem	FullCam Vegetation Type	Area Cleared (ha)
Non remnant modified grassland	-	1,749
RE 11.5.3 *Eucalyptus populnea* ± *E. melanophloia* ± *Corymbia clarksoniana* on Cainozoic sand plains/remnant surfaces	Eucalyptus woodland	178
RE 11.3.3 / 11.3.1 *E. coolabah* woodland on alluvial plains	Eucalyptus woodland	42
RE 11.3.2 *E. populnea* woodland on alluvial plains	Eucalyptus woodland	34
RE 11.3.25 *E. tereticornis* or *E. camaldulensis* woodland fringing drainage lines	Eucalyptus woodland	27
RE 11.3.1 / 11.3.3 *Acacia harpophylla* and/or *Casuarina cristata* open forest on alluvial plains	Acacia forest and woodlands	18
RE 11.4.9 *A. harpophylla* shrubby woodland with *Terminalia oblongata* on Cainozoic clay plains	Acacia forest and woodlands	9
RE 11.5.3 / 11.3.2 *E. populnea* ± *E. melanophloia* ± *C. clarksoniana* on Cainozoic sand plains/remnant surfaces	Eucalyptus woodland	7
RE 11.4.9 / 11.5.3 *A. harpophylla* shrubby woodland with *T. oblongata* on Cainozoic clay plains	Acacia forest and woodlands	5
RE 11.3.1 *A. harpophylla* and/or *C. cristata* open forest on alluvial plains	Acacia forest and woodlands	5
RE 11.8.5 *E. orgadophila* open woodland on Cainozoic igneous rocks	Eucalyptus open woodland	4
RE 11.3.3 *E. coolabah* woodland on alluvial plains	Eucalyptus woodland	3
RE 11.4.13 *E. orgadophila* open woodland on Cainozoic clay plains	Hummock shrubland - High Rainfall	2
RE 11.3.27b Sedgelands to grasslands on Quaternary deposits. Often occurs as an *Eleocharis dulcis* sedgeland	Hummock shrubland - High Rainfall	1
Total		**2,083**

4.3.1.4 Scope 1 emissions intensity of production

The Scope 1 emission intensity of production is calculated by the total t CO_2-e from NGER emission sources divided by the tonnes of run-of-mine (ROM) coal produced. This is a benchmark that can be used to assess operational efficiency, compare performance across different scales, and guide decarbonisation efforts.

4.3.1.5 Scope 2 emissions

Scope 2 emissions include CO_2 emissions from the production of electricity purchased from the NEM. These emissions have the smallest emissions of scope 1, 2 and 3. These emissions are calculated using the formula in section 4.3.1.

4.3.2 Scope 3

Scope 3 emissions were determined in accordance with the *The Greenhouse Gas Protocol* (WRI/WBCSD, 2004) where applicable. Where this was not possible, values were derived from established and recognised sources consistent with industry practice. Scope 3 energy contents and emission factors used in this assessment are summarised in Table 5.

Table 5 Energy contents and emission factors used in Scope 3 calculations

Emission source	Energy Content	Units	Scope 3 emission factor	Units
Diesel [1]	38.6	GJ/kL	17.3	kgCO_2-e/GJ
Purchased Queensland Electricity [1]	-	-	0.09	kg CO_2-e/kWh
PBOGS [1]	38.8		18.0	kg CO_2-e/GJ
Transport - HGV Articulated >33 t [2]	-	-	0.0599	kg CO_2-e /t.km
Transport - HGV Articulated >3.5 – 33 t [2]	-	-	0.0767	kg CO_2-e /t.km
Bulk Carrier Shipping Average [2]	-	-	0.00353	kg CO_2-e/t.km
Coking Coal [1]	30	GJ/t	92.0	kg CO_2-e/GJ
Bituminous Coal [1]	27	GJ/t	90.24	kg CO_2-e/GJ
Waste to Landfill - Industrial solid waste [1]	-	-	1.3	t CO_2-e/t
Wastewater treatment - Unmanaged Aerobic treatment [1]	-	-	0.1229	t CO_2-e/t
Waste Incineration - Industrial Waste [1]	-	-	1.649	t CO_2-e/t
Aurizon rail transport [3]	-	-	0.01462	kg CO_2-e/t.km

[1] DCCEEW, 2025
[2] Department for Energy Security and Net Zero, 2025
[3] Aurizon 2024 Sustainability Report

4.3.2.1 Scope 3 emissions from coal distribution

The Project will produce 60% metallurgical and 40% thermal coal, exporting to markets across Asia, India, Europe, and South America via the DBCT, south of Mackay and the NQXT, north of Bowen.

The distribution of coal involves the transport of coal product to DBCT or NQXT via Aurizon owned trains and then shipping to international markets. The distribution of coal from receiving ports to the point of final use is not included in this assessment due to limited data availability and Stanmore’s limited influence over these emissions.

Emissions from rail freight are calculated by multiplying the total tonnage railed by the distance railed. The resulting tonne-kilometres are then multiplied by the operational GHG emissions intensity as per the Aurizon 2024 Sustainability Report (Aurizon 2024), (Table 5). Data on rail and shipping locations (Table 6) along with the respective tonnage of product coal transported to each destination (Appendix A, Table A1).

Table 6 **Coal Distribution by destination, distance, and attributable percentage of product coal**

Transport type	Destination Port	Distance (km)	Percentage of product coal distributed
Rail	DBCT	172	88%
	NQXT	248	12%[2]
Ship	Japan - Kashima	9,008	45%
	Europe – Rotterdam	20,707	25%
	India – Visakhapatnam [1]	9,599	15%
	Vietnam – Haiphong [1]	9,390	10%
	Brazil	15,109	5%

[1] Shipping routes sourced through seadistances.org. Where the nearest port was unavailable the next closest ports for India and Vietnam were chosen

[2] Railing to NQXT could be between 10 – 15% of total product coal railed. This assessment has used a reasonable estimate of 12%, and overall scope 3 estimates would be immaterially changed if a slightly lesser or higher percentage was used.

Emissions resulting from shipping of coal used The Department of Energy Security and Net Zero UK (DSENZ, 2025) average bulk carrier emission factor (Table 5). The respective tonnage and of coal and distance per destination was multiplied by the EF. All shipping was conservatively assumed to occur via DBCT (furthest Port from destination ports) due to limited information on export port allocation by destination.

4.3.2.2 Scope 3 emissions from upstream processing of fuel and energy

EFs in the National Greenhouse Accounts Factors (Table 5) for the upstream extraction and processing of liquid fuels (diesel oil and PBOGS) are applied to diesel consumption data provided by Stanmore to evaluate total Scope 3 GHG emissions resulting from the production of liquid fuels for the Project.

Similarly, the Queensland Scope 3 electricity EF (Table 5) is applied to the provided electricity consumption to estimate total upstream emissions associated with generation and delivery of purchased electricity.

4.3.2.3 Scope 3 emissions from upstream transportation

Upstream transport emissions were estimated by multiplying Stanmore supplied tonnage and distance travelled for each transport task to calculate tonne kilometres, then applying the relevant articulated heavy goods vehicle emission factors (DESNZ, 2025).

4.3.2.4 Scope 3 emissions from downstream waste

The Project's waste sources are categorised as either:

- Municipal solid waste to landfill
- Industrial waste incineration
- Wastewater for unmanaged aerobic treatment

The total tonnage of each waste category is then multiplied the respective EF (Table 5). The downstream emissions of waste do not include transportation to the waste processing facility due to data unavailability and relative immateriality.

4.3.2.5 Scope 3 emissions from end use of coal

Emissions resulting from the end use (combustion) of coal are estimated using the emissions factors provided in the NGER Determination. Bituminous and coking coal EF (Table 5) were applied to thermal and metallurgical coal, respectively, with all product coal assumed to be combusted. All emissions from the combustion of coal are assumed to be emitted to the atmosphere without mitigation measures applied.

The quantity of coal projected to be sold by country along with the percentage of total LOM coal is shown in Appendix A (Table A1). Specific end user companies are not disclosed in this report due to commercial sensitivity; however, these may be supplied by Stanmore upon request. Japan is the destination country expected to receive the highest quantity of coal (45%), followed by Europe (25%), India (15%), Vietnam (10%) and Brazil (5%). The Nationally Determined Contributions (NDCs) for Paris Agreement commitments of end user countries are shown in Appendix A (Table A2).

4.3.2.6 Scope 3 emissions from purchased goods and services

Emissions from purchased goods and services are estimated using an average emission factor derived from 2024 IPC expenditure data within the Planet Price platform, a database that links financial expenditure to GHG emissions[3]. This emission factor represents the average carbon intensity (t CO_2-e per dollar spent) for expenditure categories not otherwise captured in the inventory, including infrastructure maintenance and repairs, pipeline services, electrical power transmission engineering, and construction materials for roads and rail.

The resulting average emission factor was applied to forecasted expenditure for future years. Multiplying the factor by predicted annual spend provided year-on-year estimates emissions attributable to purchased goods and services.

4.3.2.7 Scope 3 emissions from capital goods

Emissions from capital goods were estimated using the spend based method described in section 4.3.2.6. Where specific expenditure data was available for key construction materials or infrastructure items, these were estimated separately, with corresponding expenditure excluded from the spend based dataset to avoid double counting. The majority of capital goods are expected to be purchased within the first year of the Project.

4.3.2.8 Scope 3 emissions from travel and employee commuting

Worker commuting for the Project involves both road and air travel. Road travel encompasses local driving and bus transport. The proportion of workers using each mode of commute was provided by Stanmore. These proportions were subsequently applied to the projected workforce for each year of the Project to estimate the annual number of workers using each commuting method.

There are three modes of transportation involved in worker commute:

Personal vehicle travel (road):

- Workers living locally (e.g. in Moranbah) travel with personal light vehicles approximately 27 km between Moranbah and the site,
- Drive in drive out (DIDO) workers travel 176 km between Mackay and the site on shift roster changeover.
- Fly-in fly-out (FIFO) workers travelled 30 km to and from their ‘home’ airport for each flight, on shift roster changeover.

[3] https://planetprice.io/

Bus travel:

- DIDO and FIFO workers use Volvo buses to transport workers approximately 40 km from worker accommodation villages to site on a daily basis.
- FIFO workers travel approximately 152 km between Mackay and worker accommodation villages on shift roster changeover[4].

Air travel:

- ~70% of FIFO workers are expected to fly between Brisbane and Moranbah, whilst the remaining are expected to fly between Brisbane and Mackay.

4.3.2.8.1 *Road Travel*

Emissions from road commuting of workers were estimated based on fuel consumption of the vehicle:

- Light vehicles: The most sold vehicle in Australia in 2024 was the Ford Ranger, with an average fuel consumption of 7.8 L/100 km (based on the 2.0 L and 3.0 L variants).
- Buses: Volvo reports that hybrid models are approximately 37% more fuel efficient than their diesel counterparts, equating to 25.7 L/100 km. As diesel buses are assumed for this assessment, a fuel consumption rate of 35.2 L/100 km was applied.

Fuel consumptions were then multiplied by projected annual trips. Bus activity was assumed to be constant for each year and estimated at 944 trips per year between Mackay and worker accommodation villages, and approximately 2,000 trips per year (number of trips per annum varies as workforce numbers change) between worker accommodation villages and the site. Emissions factors in Schedule 1, NGER Determination (Table 3) were then applied to the relative fuel consumptions to evaluate total GHG emissions per year.

4.3.2.8.2 *Air travel*

Emissions from FIFO workers are estimated based on an emission factor provided by Stanmore's Corporate Travel Management service (Table 3) that outlines CO_2-e emissions per seat per flight between Brisbane and Moranbah or Mackay. The emission factor was then multiplied by the projected number of seats occupied per year based on an assumption of two flights per week over 48 weeks.

4.4 Limitations and assumptions

The assessment has been conducted using activity data provided by Stanmore. Katestone makes no claim as to the accuracy of this data. The following assumptions were applied due to data limitations:

- All PBOGs were considered to be used for lubricating purposes in this assessment, hence energy consumption and emissions are reported.
- Scope 3 emissions do not include return trips of ships or trains
- Rail freight services and shipping services are not purchased by Stanmore (Scope 3 category 9)
- Downstream combustion emissions for coal were estimated using Australian emission factors for coking coal and bituminous coal, irrespective of destination country. These were based upon total tonnes for the LOM of 17.81 Mt coking coal (60%) and 12.16 Mt bituminous coal (40%).

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[4] This is a conservative overestimate as a proportion of workers will fly to Moranbah, which is closer to worker accommodation villages than Mackay

5. RESULTS

5.1 Summary

The GHG emissions associated with the Project for Scope 1, Scope 2, and Scope 3 emissions over the construction, operational and rehabilitation phases of the mine are presented in Table 7. The Project is considered a medium to high emitter under the GHG Guideline and is required to consider all Scope 3 emissions and develop a GHG abatement plan.

Table 7 Summary of GHG Emissions associated with the Project

Category	Measure	Emissions (Mt CO_2-e)			
		Construction (1 year)	Operation (15 years)	Rehab (10 years)	Total LOM (26 years)
Scope 1	Average annual emissions	0.008	0.084	0.00022	0.049
	Total emissions	0.008	1.26	0.0022	1.27
Scope 2	Average annual emissions	-	0.012		0.0070
	Total emissions	-	0.18		0.18
Scope 3	Average annual emissions (within Australia)	0.039	0.057	0.00041	0.034
	Average annual emissions (outside Australia)	-	5.34		3.08
	Total emissions (within Australia only)	0.039	0.85	0.0041	0.89
	Total emissions (outside Australia only)	-	80.10		80.10
Total (scope 1, 2 and 3)	Total GHG Emissions	0.047	82.40	0.0063	82.45
	Average annual emissions (within Australia)	0.047	0.15	0.00063	0.09
	Average annual emissions (within and outside Australia)	0.047	5.49	0.00063	3.17

The total LOM GHG emissions are estimated to be 82.45 Mt CO_2-e. Of this:

- LOM Scope 1 emissions are estimated at 1.27 Mt CO_2-e, with an annual average of 0.049 Mt CO_2-e.
- LOM Scope 2 emissions are estimated at 0.18 Mt CO_2-e, with an annual average of 0.007 Mt CO_2-e.

- LOM Scope 3 emissions are estimated at 0.89 Mt CO_2-e within Australia and 80.10 Mt CO_2-e outside Australia.

5.2 NGER Category Energy and Emissions

The total energy consumed for the LOM is estimated at 13,068,288 GJ (Table 8). Diesel used in stationary plant and machinery is the dominant energy source, accounting for ~82% of LOM energy consumption, followed by electricity consumption (~8%), and diesel used in explosives (~4%). The Project will not generate electricity, as electricity will be purchased from the national electricity market (NEM).

Table 8 Energy Consumed by NGER category for LOM of Project

Source	Energy Consumed (GJ)
Diesel – stationary	10,715,104
Diesel – transport	563,953
Oils	222,854
Greases	30,492
Diesel – explosives	563,884
Electricity	972,000
Total	**13,068,288**

The NGER reportable (combined Scope 1 and 2) LOM emissions are estimated at 1,353,095 t CO_2-e (Table 9):

- Diesel combustion for stationary plant is expected to be the largest contributor to the NGER reportable inventory with 752,200 t CO_2-e (~56%) to Scope 1 and 2 emissions
- Fugitive methane emissions are expected to be the second largest contributor of Scope 1 emissions, totalling 377,066 t CO_2-e (28%)
- Diesel combustion for transport vehicles is expected to contribute 39,708t CO_2-e (~3%) to Scope 1 emissions
- PBOGs contribute 3,220 t CO_2-e (~0%) to Scope 1 emissions
- Scope 2 emissions from electricity purchased from the Queensland grid are estimated to result in 180,900 t CO_2-e (~13%)
- The maximum annual NGER reportable Scope 1 and Scope 2 GHG emissions are estimated at 109,984 t CO_2-e in 2034

The NGER reportable emission inventory contributes ~93% to the Project's total LOM Scope 1 and 2 emissions of 1,454,925 t CO_2-e (Table 9). The Scope 1 sources not reported to the NGER Scheme include:

- Land clearing, estimated to result in 62,449 t CO_2-e and contribute ~4% to the Project's total LOM Scope 1 and 2 emissions inventory.
- Diesel used in explosives, estimated to result in 39,381 t CO_2-e and contribute ~3% to the LOM Scope 1 and 2 emissions inventory.

Table 9 Scope 1 and Scope 2 emissions from the Project (t CO_2-e) by year and emissions source

Year	Scope 1							Scope 2	Total	Total Reportable to NGER Scheme
	Diesel – stationary	Diesel – transport	Oils	Greases	Fugitives	Land clearing [1]	Explosives [1]	Electricity		
2028	7,723	408	32	1	0	0	0	0	**8,163**	**8,163**
2029	40,636	2,145	168	6	9,272	62,449	1,904	12,060	**128,641**	**64,288**
2030	61,892	3,267	256	9	15,699	-	2,234	12,060	**95,418**	**93,184**
2031	59,921	3,163	248	9	18,361	-	2,368	12,060	**96,130**	**93,762**
2032	62,861	3,318	260	9	19,830	-	3,017	12,060	**101,356**	**98,339**
2033	63,510	3,353	263	9	21,358	-	3,580	12,060	**104,133**	**100,552**
2034	69,578	3,673	288	10	24,375	-	3,739	12,060	**113,723**	**109,984**
2035	55,056	2,906	228	8	22,118	-	3,472	12,060	**95,848**	**92,376**
2036	52,623	2,778	218	7	22,906	-	2,656	12,060	**93,248**	**90,593**
2037	46,873	2,474	194	7	23,894	-	3,087	12,060	**88,590**	**85,503**
2038	51,064	2,696	211	7	28,906	-	2,671	12,060	**97,616**	**94,944**
2039	42,713	2,255	177	6	33,411	-	2,344	12,060	**92,966**	**90,622**
2040	48,255	2,547	200	7	41,119	-	2,840	12,060	**107,028**	**104,188**
2041	40,617	2,144	168	6	44,160	-	2,280	12,060	**101,435**	**99,155**
2042	40,762	2,152	169	6	44,486	-	2,263	12,060	**101,899**	**99,635**
2043	6,056	320	25	1	7,168	-	925	12,060	**26,555**	**25,630**
2044	515	27	2	-	-	-	-	-	**544**	**544**
2045	515	27	2	-	-	-	-	-	**544**	**544**
2046	129	7	1	-	-	-	-	-	**136**	**136**
2047	129	7	1	-	-	-	-	-	**136**	**136**
2048	129	7	1	-	-	-	-	-	**136**	**136**
2049	129	7	1	-	-	-	-	-	**136**	**136**
2050	129	7	1	-	-	-	-	-	**136**	**136**
2051	129	7	1	-	-	-	-	-	**136**	**136**
2052	129	7	1	-	-	-	-	-	**136**	**136**
2053	129	7	1	-	-	-	-	-	**136**	**136**
Total	**752,200**	**39,708**	**3,114**	**107**	**377,066**	**62,449**	**39,381**	**180,900**	**1,454,925**	**1,353,095**

[1] *Not reported under NGER*

5.2.1 Emissions Intensity of Production

The projected average Scope 1 emission intensity (EI) (excluding land clearing) is estimated at 0.0272 t CO_2-e / t ROM coal. This benchmark is used to determine the effectiveness of decarbonisation measures (section 6).

5.3 Scope 3 emissions

The total LOM Scope 3 emissions are estimated to be 80,995,551 t CO_2-e (Table 10). End use of sold products is the highest Scope 3 emission category for the LOM estimated to be 78,794,422 t CO_2-e (~97% of total), followed by downstream transport with 1,387,359 t CO_2-e, ~2% of total) and purchased goods and services (436,036 t CO_2-e, ~1% of total).

Table 10 LOM Scope 3 emissions by category

Category	Emissions (t CO_2-e)
Category 1 Purchased Goods and Services	436,036
Category 2 Capital Goods	68,700
Category 3 Fuel & Energy related activities	224,009
Category 4 Upstream Transport	21,462
Category 5 Waste Generated in operations	31,351
Category 6 Business Travel	15,453
Category 7 Employee Commuting	16,759
Category 9 Downstream Transport - including rail within Australia and shipping overseas	1,387,359
Category 10/11 Processing / Use of Sold Products	78,794,422
TOTAL	**80,995,551**

Annual estimates of Scope 3 emissions per category are provided in Table 11. The end use of sold product coal represents the most significant source of Scope 3 emissions for the Project. Combustion of coal overseas is projected to result in 78,794,422 t CO_2-e. This value has been obtained using the default emission factors for thermal and metallurgical coal (NGER Determination). No coal from the Project will be combusted within Australia.

Table 11 Scope 3 emissions (t CO2-e) by year and Scope 3 category

Phase	Category	1	2	3	4	5	6	7	9	10|11	Total
	Year	Emissions t CO2-e									
Construction	2028	0	35,619	2,050	45	0	717	823	0	0	39,255
Operations	2029	16,011	37,163	12,409	1,256	2,090	897	1,075	64,739	3,613,538	3,749,177
	2030	32,619	2,958	18,052	1,397	2,090	883	1,050	124,040	7,016,712	7,199,801
	2031	36,825	3,159	17,529	1,416	2,090	883	1,047	132,495	7,592,003	7,787,446
	2032	39,635	3,258	18,310	1,551	2,090	910	1,089	136,625	7,813,332	8,016,799
	2033	41,761	3,233	18,482	1,662	2,090	910	1,093	135,594	7,722,219	7,927,044
	2034	44,150	3,233	20,093	1,714	2,090	938	1,125	135,586	7,701,403	7,910,333
	2035	34,510	2,576	16,237	1,610	2,090	841	990	108,021	6,156,889	6,323,764
	2036	31,802	2,113	15,591	1,444	2,090	841	976	88,625	5,049,501	5,192,985
	2037	27,433	1,909	14,065	1,506	2,090	814	940	80,049	4,547,745	4,676,551
	2038	30,668	1,854	15,177	1,442	2,090	855	1,001	77,743	4,416,568	4,547,399
	2039	24,055	1,670	12,960	1,348	2,090	800	926	70,024	3,980,610	4,094,483
	2040	27,708	1,750	14,432	1,464	2,090	828	955	73,406	4,158,169	4,280,802
	2041	24,472	1,734	12,404	1,329	2,090	786	894	72,739	4,086,088	4,202,537
	2042	24,387	1,729	12,442	1,326	2,090	786	888	72,511	4,081,784	4,197,943
	2043	0	362	3,228	943	2,090	551	574	15,162	857,861	880,771
Rehab	2044	0	0	137	2	0	234	153	0	0	526
	2045	0	0	137	2	0	234	153	0	0	526
	2046	0	0	34	1	0	234	153	0	0	421
	2047	0	0	34	1	0	234	153	0	0	421
	2048	0	0	34	1	0	234	153	0	0	421
	2049	0	0	34	1	0	220	121	0	0	375
	2050	0	0	34	1	0	220	121	0	0	375
	2051	0	0	34	1	0	220	121	0	0	375
	2052	0	0	34	1	0	192	92	0	0	319
	2053	0	0	34	1	0	192	92	0	0	319
	Total	**436,036**	**68,700**	**224,009**	**21,462**	**31,351**	**15,453**	**16,759**	**1,387,359**	**78,794,422**	**80,995,551**

6. DECARBONISATION PLAN

6.1 Introduction

This Decarbonisation Plan addresses requirements of the Terms of Reference (section 2) and the GHG Guidelines.

The Project is considered a medium to high emitter, with average Scope 1 GHG emissions of 0.049 Mt CO_2-e per year (Table 7) over the life of the Project including the rehabilitation and closure period and 0.084 Mt CO_2-e per year (Table 7) over the operational period (15 years). The Project is therefore required to identify emissions mitigation and management practices and provide a GHG abatement plan.

6.2 Stanmore's Sustainability Policy

Stanmore acknowledge Australia's commitment to net zero emissions by 2050 and will continue aligning its decarbonisation efforts with the Australian Government's commitments to contribute to the goal of the Paris Agreement.

"Stanmore recognises the broad ranging implications of its operations in terms of actual and potential environmental, social, and economic impacts. As a result, to improve and enhance environmental, social, and economic outcomes for all of its stakeholders, Stanmore is committed to embedding sustainability across the entire organisation and operations[5].

This is given effect in decision making by the following principles:

- "Reducing the greenhouse gas emissions intensity of our operations to contribute to the global transition to a lower carbon economy and mitigate overall impacts of climate change
- Reporting in a transparent and honest manner with respect to our ESG and sustainability commitments, activities, and performance; and
- Establishing systems and processes for the continual improvement of sustainability practices and performance"

6.3 Goals and Objectives

Stanmore intends to meet the Safeguard Mechanism emission reduction requirements for IPC, inclusive of the Project, through activities that reduce, substitute, and/or offset emissions from the Project.

The Project will be one of several of Stanmore's Safeguards facilities and decarbonisation will be applied at the facility or facilities where it makes the most economic sense.

The Project will make a negligible contribution to Australia's emissions in 2050, as it will be in the rehabilitation and closure period.

6.4 Reference Point

Two Project reference points are provided: the projected Scope 1 emissions intensity of production during operation (section 5.2.1), and the maximum annual Scope 1 emissions projected during operations.

The projected average Scope 1 emission intensity (EI) is estimated at 0.0272 t CO_2-e / t ROM coal.

[5] https://stanmore.au/wp-content/uploads/2025/11/Stanmore-Sustainability-Policy.pdf

The projected maximum annual scope 1 emissions is 116,581 t CO_2-e which occurs in 2029 and includes land clearing. The projected annual maximum that includes operations only is 101,663 t CO_2-e and occurs in 2034.

6.5 Economic assessment of potential decarbonisation measures

Stanmore commissioned an economic cost-benefit review of potential decarbonisation technology and processes for application in its operations and has made a commitment for application of these technologies in the Project and/or trials of these technologies and/or further feasibility assessment of these technologies. These are summarised below in Table 12. The 'net present cost' of various technologies was evaluated where net present cost considers, for each technology, the capital investment cost, operational costs and savings and the savings in carbon credit (e.g. ACCU) costs. Where net present cost is positive, this demonstrates that the technology has not reached suitable technical or economic feasibility for implementation at the Project.

Table 12 Economic feasibility assessment of potential decarbonisation measures

Assessed Technology or Process	Comments and Findings	Benefit
Committed		
Electric dragline	The Project will utilise an electric dragline rather than diesel excavators for the removal of overburden.	Avoidance of 155 kt CO_2-e for LOM
Power purchase agreement (PPA)	Tender process for PPA to be undertaken in 2026 for supply of carbon neutral or renewably generated electricity	Reduction in Scope 2 emissions up to 100%
Premium diesel used	Use of premium diesel increases fuel use efficiency. IDE mine plan and GHG assessment based on use of premium diesel.	Avoidance of 29 kt CO_2-e for LOM
Replace light vehicles with battery electric vehicle (BEV) or Hybrid	Stanmore is trialling a mine-ready BEV Ute – availability on the market is currently limited	TBC
Solar Powered Crib Hut	Replacement of diesel genset with solar PV and battery in crib hut and site/Project office design	Avoidance of 870 t CO_2-e for LOM
Not currently technically and / or commercially feasible – further feasibility assessment required		
Electric Excavator	Increased CAPEX for electrical infrastructure and restriction in operating envelope means only one of two major excavators could be 'electrified'. Plan to be revisited before FID decisions are made regarding equipment sourcing. Medium positive net present cost	Potential avoidance of 34 kt CO_2-e for LOM.
Dual fuel with dynamic gas blending	Dual fuel engine retrofitted to utilise CSG-diesel blend. Diesel cost savings offset CAPEX for upgrade. Engine reliability and maintenance cost impact requires assessment. Option not economic if purchase price of gas is $12/MJ, i.e. market rate. Stanmore considering trial at another mine site with CAT trucks using coal seam gas from that mine site (option not available for the Project due to low coal seam gas content). High positive net present cost of depending on source of gas.	Potential avoidance of 36 kt CO_2-e for LOM
Pre-drainage and flaring CSG before mining	CSG domains quantified for NGER system reporting. Gas content too low for all areas <100 m (i.e. all areas to be mined for the project) for pre-drainage and flaring or capture for use (Appendix C, Thomson and Thomson, 2025b).	Nil
BEV Haul Trucks	Stanmore has joined CAT Pathways Project to assess the two Early Learner CAT793XE trucks delivered to the Pilbara for BHP/Rio pilot trial.	Potential avoidance of 311 kt CO_2 -e for LOM

	Developing technology not commercially available in Australia	
D11 XE Dozer	Electric Drive D11 dozers being released by Caterpillar in 2027. Developing technology requiring further assessment. Potential for half dozer fleet being electric if technically and commercially feasible.	Potential avoidance of 33 kt CO_2-e for LOM
Behind the Meter (BTM) solar farm	Stanmore is assessing the connection requirements with ERGON to build a 4.9MW behind the meter (BTM) solar farm for IPC to provide renewable electricity to the operations.	Reduction in Scope 2 emissions up to 100%
LNG or CNG Powered Road Haul Trucks	Stanmore is investigating the production of LNG from CSG at another mine site. This could be used as a diesel substitute for road haul trucks used to transport ROM coal to IPC CHPP.	TBC
Retirement of old plant	Retirement of inefficient ROM Coal feed system at IPC CHPP.	TBC
Soil carbon amelioration	Stanmore will investigate the RemoraCarbon exhaust capture system and apply CO_2 as feedstock for algae production and soil carbon sequestration.	TBC
Technology considered but rejected		
Haul Truck Automation	High cost of capital with some OPEX savings, but little carbon reduction.	Minimal
Diesel Electric trucks with 'trolley assist'	High CAPEX. Very high net present cost. Site unsuitable for required infrastructure	Potential avoidance of 18 kt CO_2-e for LOM
Coal conveyor to link IDE with IPC CHPP	Significant CAPEX with low carbon reduction. Very high net present cost.	Potential avoidance of 29 kt CO_2-e for LOM
In-pit crushing and conveying (IPCC) system for coal moved out of the pit	High CAPEX and significant pit redesign required, not feasible for the Project.	n/a
IPCC system for waste moved out of the pit	Very high CAPEX and OPEX demonstrated at RioTinto/Glencore Clermont Mine, not feasible for the Project.	n/a
Hydrogen addition to diesel engines	Trial by Theiss demonstrates thermodynamic inefficiency.	TBC
Carbon mineralisation	Still in R&D stages	n/a

6.6 Management Controls to Reduce GHG Emissions

The following management controls will be applied for the Project by Stanmore, where practicable and cost-effective, to achieve the objectives and key result areas (Table 13).

6.6.1 Avoid

Stanmore is unable to avoid GHG emissions in carrying out the activities associated with the Project, other than by avoiding the unnecessary clearance of vegetation to avoid Scope 1 emissions from land clearing. The option of not proceeding with the Project is not considered economically viable.

6.6.2 Reduce

Stanmore's priority is to reduce Scope 1 emissions through diesel use efficiency on site and, if technically and economically viable, abatement of fugitive methane emissions.

Stanmore is continually investigating and testing feasible options for emissions reduction through increased diesel use efficiency and electrical efficiency across all of its facilities. The main areas of focus include investigating the business case of:

- Premium diesel (3.9% fuel burn benefit, reducing diesel consumption by 3.9%)
- Electric shovels or excavators
- Electric haul trucks
- Electric road trains
- Use of electric conveyors
- Use of electric trolley assist haul trucks

Implementation of these options will occur if and when the business case demonstrates that they are technically and commercially feasible.

6.6.3 Substitute

Stanmore will commission an electric dragline at Project commencement as the preferred operating case for overburden removal, supporting Project feasibility. This will displace Scope 1 diesel emissions with Scope 2 electricity emissions. Relative to a diesel mobile equipment case, this is expected to reduce emissions by 155,000 t CO_2-e over the LOM.

Stanmore will evaluate the cost-effectiveness of engaging in a Power Purchase Agreement (PPA) with a supplier of renewably generated electricity, for use by the Project. A PPA for renewably generated electricity would both support investment in renewably generated electricity in Queensland, helping to meet Queensland's targets for renewable energy, and provide for significantly reduced Scope 2 emissions for the Project. Purchasing (or producing) renewably generated electricity will incur zero (0) GHG emissions for that proportion of electricity purchased or produced.

Stanmore is currently trialling a mine-ready BEV Ute and will investigate replacement of light vehicles with electric vehicles once they are more commercially available and financially feasible. This would displace Scope 1 diesel emissions with Scope 2 electricity emissions to reduce CO_2-e emissions over the LOM.

Stanmore proposes to replace a diesel genset with a solar PV and battery system at the Project's crib hut. This would displace an estimated 870 t CO_2-e of diesel emissions for the LOM.

Stanmore is continually investigating and testing feasible options for emissions reduction through the substitution of diesel equipment with electric equipment. This includes the potential electrification of conveyors, excavators, haul trucks, road trains and other machinery that uses diesel as fuel. Implementation of these options will occur if and when the business case demonstrates that they are technically and commercially feasible.

6.6.4 Offset

The Project would be part of the IPC facility for the purposes of the Safeguard Mechanism. The Project, as part of the IPC facility, would be required to purchase and surrender ACCUs or use SMCs if it becomes subject to the Safeguard Mechanism emissions reduction requirements. Stanmore commits to implementing all technically and commercially feasible decarbonisation options before seeking to offset residual emissions with ACCUs or SMCs. Stanmore will purchase ACCUs that are produced in Queensland (DETSI, 2026) where they are available and cost-effective. Where offsets are proposed for carbon abatement Stanmore will monitor the offset market using internally sourced information and reputable third party market analysts to identify any market constraints.

Table 13 **Key result areas and management controls for the Project by GHG abatement hierarchy**

Priority	Key Result Area	Management Controls and Timing
Avoid	KRA 1: Avoid unnecessary clearance of woody vegetation	Map and identify woody vegetation to be excluded from damage or clearance prior to construction
Reduce	KRA 2: Mobile and stationary plant emissions are reduced from the base case to support emissions reductions as required under the Safeguard Mechanism and Queensland's emission reduction targets	Mine layout and run of mine will be optimised for diesel use efficiency through explicit planning and scheduling from Project Year 1 Emissions reduction in plant will be realised through ongoing process monitoring and optimisation Use of premium diesel in all transport and stationary plant will be reviewed before commencement and implemented where economically feasible Research and evaluation of dual fuel technologies in heavy diesel vehicles and implementation if economically feasible and if sources of gas supply prove favourable Right sized machinery and load optimisation on commissioning to reduce fleet hours
Substitute	KRA 3: Substitute diesel mobile equipment used for overburden removal with an electric dragline	Commission electric dragline at commencement of operations (Project Year 1)
	KRA 4: Emissions due to electricity usage are reduced where cost effective and technically feasible by using renewable electricity	Purchase renewably generated electricity where it is cost effective for Project operation Install onsite renewable electricity generation where a positive business case exists (e.g. replacing diesel genset with renewable electricity to power the crib hut.)
Offset	KRA 5: Apply cost-effective options to offset balance of annual emissions against production adjusted baseline after decarbonisation and abatement	Purchase ACCUs produced in Queensland where available and cost effective and surrender as required, otherwise ACCU/SMCs purchased in rest of Australia. Identify best management practices to increase post mining land use (PMLU) carbon stock in soil and vegetation, for application in progressive rehabilitation

6.7 Mitigating Scope 3 emissions

The majority of Scope 3 emissions will be due to the combustion of the product coal in client countries (Appendix A). These countries are signatories to the Paris Agreement and are responsible for reducing their own GHG emissions and becoming net zero by their specified timeframes.

The measures that Stanmore are undertaking to reduce diesel use through efficiency measures will be reflected in a reduction in both scope 1 and scope 3 emissions.

Stanmore will investigate the business case and implement where appropriate, targeted policy interventions to mitigate emissions associated with their supply chain. This may include:

- Voluntary provision of consumer's GHG and decarbonisation disclosures
- Collaboration with low carbon consumer end users including steel manufacturers, research groups and industry organisations.

Within Australia, Stanmore will regularly review options to reduce GHG emissions across its supply and value chain such as distribution of coal product via low emission transportation providers, and utilisation of low emissions bus fleets to transport workers. Stanmore currently contracts a rail freight provider which is seeking to have 25% of their electricity requirements from renewable sources. Stanmore has partnered with a bus fleet supply company to introduce zero-emission, battery-electric buses for workforce transportation in the Bowen Basin near Moranbah, Queensland.

6.8 Assessment of proposed GHG mitigation measures

An assessment of proposed GHG abatement measures for the Project is provided in Table 14, which considers the timeframe for implementation, key risks, a comparison with relevant best practice environmental management standards, an estimate of emissions reductions resulting from the abatement measure, and consideration of whether the inclusion of an ongoing monitoring program for the abatement measure is necessary.

The timeframes for implementation are presented as Immediate, Near, Medium, and Long-term. These timeframes are defined as:

- short-term = 0 – 2 years
- medium-term 3 - 5 years
- long-term 5+ years

'Approaching best practice' indicates the abatement measure is dependent on the degree of implementation. An 'embedded' monitoring program requirement indicates the abatement measure should become standard operating procedure once implemented.

Table 14 Project GHG abatement hierarchy including key result areas and management controls

Priority	Mitigation measure	Timeframe	Risks	Opportunities	Industry Standard	Emissions reduction estimate for LOM ($t\ CO_2$-e)
Avoid (KRA 1)	Avoid unnecessary vegetation clearance	Short term with regular evaluation	• Unauthorised clearance	• Reduced rehabilitation requirements leads to shorter land management obligations and cost savings • Ability to improve carbon sequestration of existing land to support broader sustainability commitments	Best	TBD
Reduce (KRA 2 & 3)	Reduce mobile and stationary plant emissions in the base case	Short term with regular evaluation over medium and long term	• Optimising mine layout, scheduling and fleet size may constrain operational flexibility • High capital and operational costs associated with premium diesel, dual fuel technologies and process operations may lead to cost overruns and underestimated emission reductions • Dependence on gas availability and quality (KRA 3) as well as emerging dual fuel technologies may limit long term viability of abatement	• Reduced diesel usage reduces operating costs and exposure to volatile fuel markets • Optimised layout, fleets and loading increase productivity and reduce maintenance requirements • Reductions support Safeguard Mechanism compliance and Queensland's emission reduction goals	Best	TBD
Substitute (KRA 3 & 4)	Substitute diesel mobile equipment used for overburden removal with an electric dragline	Short term	• Reliance on a single dragline increases downtime risk and require fallback to diesel machinery.	• Electrified equipment leads to further decarbonisation as grid decarbonises and offers the potential to couple dragline with onsite renewable electricity generation	Best	155,000

				• Reduced diesel usage reduces operating costs and exposure to volatile fuel markets		
	Reduce emissions from electricity usage through substitution where cost effective and technically possible	Short term with regular evaluation over medium term	• Costly PPAs and / or no availability • Cost overruns, installation delays and intermittent generation for onsite renewable electricity generation	• Renewable PPAs allow for an immediate reduction of emissions, without significant capital or planning • Long term electricity security with potential of grid connections allowing for new business models	Best	Up to 180,900
Offset (KRA – 5)	Purchasing of offsets (>30%) after decarbonisation KRAs to meet emissions against production adjusted baseline	Annually	• Reliance on offsets exposes Stanmore to carbon markets, resulting in economic losses • Offsets may discourage investments from stakeholders	• Potentially cost-effective way to manage difficult residual emissions and support meeting interim targets as technology advances	Established	TBD

6.9 Monitoring, Evaluation, and Reporting

Stanmore will monitor and record all energy use and production within the IPC facility boundary (inclusive of the Project) consistent with NGER requirements and methods. This data and the methods for monitoring will be available and subject to periodic internal validation and independent audit.

IPC is subject to the Safeguard Mechanism therefore Stanmore will be required to demonstrate year-on-year proportional reduction in emissions relative to its production-adjusted baseline when its emissions are above the threshold.

Stanmore will report its progress in emissions reduction and minimisation of Safeguard Mechanism liabilities to the Board and report its progress in annual emissions reduction in the Sustainability Report published on its website. Stanmore provides public reporting on GHG emissions and reductions in its annual Sustainability Report and through annual reporting under the NGERS Act and Safeguard Mechansim, including for the Isaac Plains Complex.

Progress against the decarbonisation objective and key result areas (Table 13) will be periodically audited and reviewed.

6.10 Advancing technologies and opportunities

Stanmore will annually review the technological and commercial readiness of options that may result in improved efficiency or reduced GHG emissions in the operation of the Project.

Stanmore is committed to a process of continuous improvement to meet its decarbonisation goal and objective. It will scope new technologies and processes that may be implemented cost-effectively to improve efficiency and reduce GHG emissions. Stanmore will also continue to support the Australian Coal Industry Research Program (ACARP) in research to develop best practice environmental management measures.

Feasibility assessments will be conducted regarding options according to their technology readiness level (TRL) and their commercial readiness level (CRL). These terms were first developed by NASA (Kimmel, 2020) and are used by firms such as KPMG. Typical satisfactory adopted levels for proceeding include a TRL of 6 or above and a CRL of 5 or above. These values or similar methods may be used by Stanmore to help guide their decision making process when recommendations for investment are to be made to senior management.

6.11 Assessment of proposed GHG mitigation measures

Decarbonisation of the mining sector is a rapidly changing space, driven in large part by the Safeguard Mechanism requirements. Expected best practice is planning, designing, constructing, and operating mine sites for the efficient use of diesel (Crittenden *et al*. 2016). Electrification of plant and equipment is emerging as best practice however there are still limitations in market availability, technical feasibility, operational constraints and cost-competitiveness against traditional diesel options.

Stanmore is continually investigating a range of improved diesel-use efficiency and electrification options, and these will be implemented where feasible for the Project.

Practicable and economically feasible emission reduction, abatement, or offsetting options will be implemented when the business case is met. Each option will have its effectiveness monitored and reported (section 6.9).

7. RISKS AND LIKELY MAGNITUDE OF IMPACTS ON ENVIRONMENTAL VALUES

7.1 Impacts of GHG emissions on environmental values

The increasing concentration of greenhouse gases in the atmosphere, primarily due to the combustion of fossil fuels and deforestation, is leading to the warming of oceans, land, and atmosphere. This warming increases the heat energy available in the climate system leading to changed weather patterns including more frequent and intense extreme weather events. Australia is required to provide the United Nations Framework Convention on Climate Change (UNFCCC) with National Inventory Reports annually, biennial reports every 2 years, and National Communications every 4 years. These reports include details on total and sectoral GHG emissions, progress against reduction targets, and mitigation actions.

The Project is located in the Isaac region, Queensland. Key climate risks for this region include (DETSI, 2025)

- increased frequency of hot days (>35 ºC) and very hot days (>40 ºC)
- increased likelihood of bushfire weather
- increased likelihood of short duration high intensity rainfall
- increased pan evaporation rates
- increased frequency and severity of drought
- less frequent but more intense tropical cyclones
- warmer and more acidic ocean
- rising sea levels and more frequent coastal and open ocean extreme events.

Consequently, there is a need to reduce emissions at a state, national, and global level.

Queensland and Australia have legally committed to achieving a net zero GHG emissions economy by 2050 as their contribution to the Paris agreement goal to preferably limit warming to 1.5°C or at least well below 2°C (section 3.1.1). The relative carbon budgets (Gt CO2-e) remaining between 2025 and 2050 (Friedlingstein, 2025) to achieve these goals and the relative proportion of these budgets occupied by the Project's expected emissions are presented in Table 15.

For state and national contributions, only regulated emissions (Scope 1 and 2) that occur within Australia are included (0.0015 Gt Co2-e). Whilst the global contribution includes all expected GHG emissions across the LOM occurring both within and outside Australia (0.082 Gt CO_2-e).

Table 15 Remaining Queensland, Australian and global carbon budgets (Gt CO2-e) aligned with Paris Agreement temperature goals, and the Project life of mine emissions expressed as a share of each budget (%) (Scope 1 and 2 for Queensland and Australia; total Scopes 1 to 3 for the global budget).

Limit Degree of Warming	Project Emissions	Contributions to Emission Budgets					
		Queensland		Australia		Global	
°C	(Gt CO2-e)	Budget (Gt CO2-e)	Project %	Budget (Gt CO2-e)	Project %	Budget (Gt CO2-e)	Project %
1.5	0.0015 [1]	1.68	0.087 %	7.25	0.020 %		
	0.082 [2]					531	0.016 %
2	0.0015 [1]	2.78	0.052 %	11.91	0.012 %		
	0.082 [2]					869	0.009 %

Table Notes:
[1] Total LOM Scope 1 and 2 GHG emissions
[2] All LOM Emissions (Scope 1, 2 and 3)

The Project will contribute an insignificant fraction to the drawdown on Queensland's remaining carbon budget to achieve a net zero emissions economy by 2050 and the Project will have commenced rehabilitation and revegetation before this time. The Project's contribution to remaining national and global budgets is also insignificant.

7.2 Contribution to Queensland's Emissions Reduction and Renewable Energy Targets

Queensland has committed to three emissions reduction targets in legislation. The targets are:

i. 30% reduction in GHG emissions on 2005 levels by 2030
ii. 75% reduction in GHG emissions on 2005 levels by 2035
iii. A net zero emissions economy will be achieved by 2050

The Queensland Government has flagged that these targets will be amended and are likely to be reduced.

The Project's contribution to Queensland's emission reduction targets as included in the CEJ Act are shown in Table 16Table 16.

Table 16 Project Contribution to Queensland's emissions and renewable energy targets

Queensland Targets	Project Contribution
75% on 2005 levels by 2035	Progressive emissions reduction as per Safeguard Mechanism requirements and GHG Abatement Plan This will also contribute to meeting the 2030 target of 30% on 2005 levels
Zero net emissions economy by 2050	Progressive reduction in production-adjusted baseline emissions under Safeguard Mechanism Implementation of GHG Abatement Plan Potential purchases of renewable electricity through a PPA, or onsite electricity generation Project operational phase is projected to end in 2043, after which emissions are negligible.

8. SUMMARY

Katestone Environmental Australia Pty Ltd (Katestone) was commissioned by Stanmore ID Extension Pty Ltd (ID Extension), a subsidiary of Stanmore Resources Ltd (Stanmore), to conduct a Greenhouse Gas (GHG) assessment for the proposed Isaac Downs Extension (IDE) Project (the Project). The Project will be integrated into the Isaac Plains Complex (IPC), comprising Isaac Downs Mine (IDM) and Isaac Plains Mine (IPM). The Project will extend the life of mining activities at IDM in the Bowen Basin, approximately 15 km southeast of Moranbah.

The Project will comprise of an open cut coal mine pit and associated infrastructure, primarily mining metallurgical (steel making) coal. Approximately 46 million tonnes (Mt) of run of mine (ROM) coal will be mined over 15 years starting from 2029, with approximately 2 – 4.5 million tonnes (mined) per annum (Mtpa).

The Project requires an environmental impact statement (EIS) that will be assessed by the Queensland and Commonwealth governments. This GHG assessment has been completed in accordance with the requirements of the terms of reference (TOR) for the EIS and has been informed by Project information supplied by Stanmore, including Stanmore's in-house resources for the management of GHG.

The assessment shows the total life of mine (LOM) emissions are estimated to be 82.45 Mt CO_2-e.

Of this 26 year total:

- Scope 1 emissions contribute 1.27 Mt CO_2-e with average annual emissions of 0.049 Mt CO_2-e
    - Stationary diesel combustion and fugitive methane emissions are the largest contributors to total LOM Scope 1 emissions at 752,200 t CO_2-e and 377,066 t CO_2-e respectively
- Scope 2 emissions contribute 0.18 Mt CO_2-e, with average annual emissions of 0.0070 Mt CO_2-e
- Scope 3 emissions contribute 81.00 Mt CO_2-e with average annual emissions of 3.12 Mt CO_2-e with:
    - Emissions within Australia of 0.89 Mt CO_2-e and outside Australia of 80.10 Mt CO_2-e

The Project's combined total Scope 1 and 2 emissions are estimated to represent 0.087% and 0.020% of the remaining Queensland and Australian carbon budgets, respectively, under a pathway consistent with limiting warming to 1.5°C. Under a 2°C pathway, the corresponding contributions are 0.052% and 0.012%. The Project's total LOM emissions (Scopes 1, 2 and 3) are estimated to represent 0.016% of the remaining global carbon budget for 1.5°C, and 0.009% for 2°C.

Stanmore acknowledge Australia's commitment to net zero emissions by 2050 and will continue aligning its decarbonisation efforts with the Australian Government's commitments to contribute to the goal of the Paris Agreement. Consequently, Stanmore is developing a decarbonisation strategy and is investing in decarbonisation projects that include capturing coal seam methane and converting it to electricity at its South Walker Creek Mine. Solar projects are also being evaluated at IPC and other Stanmore facilities and connection applications have commenced. These projects will reduce Scope 1 and Scope 2 emissions and may result in Safeguard Mechanism Credits (SMC) that can be used to offset emissions from other Stanmore facilities.

The Project will produce Scope 1 and Scope 2 emissions and based upon the Queensland Greenhouse Gas Emissions guideline ESR/2024/6819 is a medium to high emitter (greater than 25 000 t $CO_{2\text{-eq/year}}$). The option to avoid emissions production through not progressing with the Project is considered economically undesirable. Stanmore intends to meet the Safeguard Mechanism reduction requirements for the IPC facility, inclusive of the Project, through the following activities to avoid, reduce, substitute, and/or offset emissions where practicable and cost-effective:

Avoid

- Minimising unnecessary clearance of vegetation to minimise emissions during land clearing activities

Reduce

- Mobile and stationary plant emissions are reduced from the base case through:
  - Optimisation of mine layout and operations
  - Optimisation of vehicles and processes for energy efficiency
  - Replacement of diesel with premium diesel
- Pre-drainage of CSG and flaring or combustion to produce electricity if technically and economically feasible
- Staff are engaged in energy efficiency and emissions reduction

Substitute

- Use of an electrically powered dragline as preferred option for overburden removal, thereby reducing diesel consumption for equipment that would otherwise be used for overburden removal
- Emissions due to electricity usage will be minimised through:
  - Purchase of renewably generated electricity through a Power Purchase Agreement where this is cost effective
  - Onsite renewable electricity generation or through electricity generation by combusting drained CSG, where technically and economically feasible

Offset

- SMC will be surrendered against Project emissions above baseline where this is the most economic use of them
- Purchase and surrender of Australian Carbon Credit Units (ACCU) generated in Queensland where feasible and cost-effective, and in the rest of Australia

The measures that Stanmore are undertaking to reduce diesel use through efficiency measures will be reflected in a reduction in both scope 1 and scope 3 emissions. Scope 3 GHG emissions associated with the transport of product coal, are expected to reduce as contracted companies meet their published emission reduction goals.

Stanmore commits to a process of continuous improvement informed by engaged staff, monitoring, evaluation, and research. They will continue to build on its current commitments including electric dragline, use of premium diesel, replace light vehicles with battery electric vehicles (BEV) or hybrid, and solar powered crib hut. Potentially feasible projects requiring further assessment include electric excavator, dual fuel technologies in haulage fleet and BEV haul trucks. New and emerging technologies will be considered as they evolve.

Stanmore will report on its emissions and emissions reduction targets through the annual NGER and Safeguard Mechanism process and through Stanmore's annual sustainability report.

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APPENDIX A END USERS OF PROJECT COAL AND LEVEL OF DECARBONISATION COMMITMENTS

Table A1 Summary ranking of destination country by quantity (%) of coal sold by the Project

Destination Country	Quantity of coal (t)	% of LOM coal
Japan	13,485,632	45%
Europe	7,492,018	25%
India	4,495,211	15%
Vietnam	2,996,807	10%
Brazil	1,498,404	5%
Total	29,968,071	100%

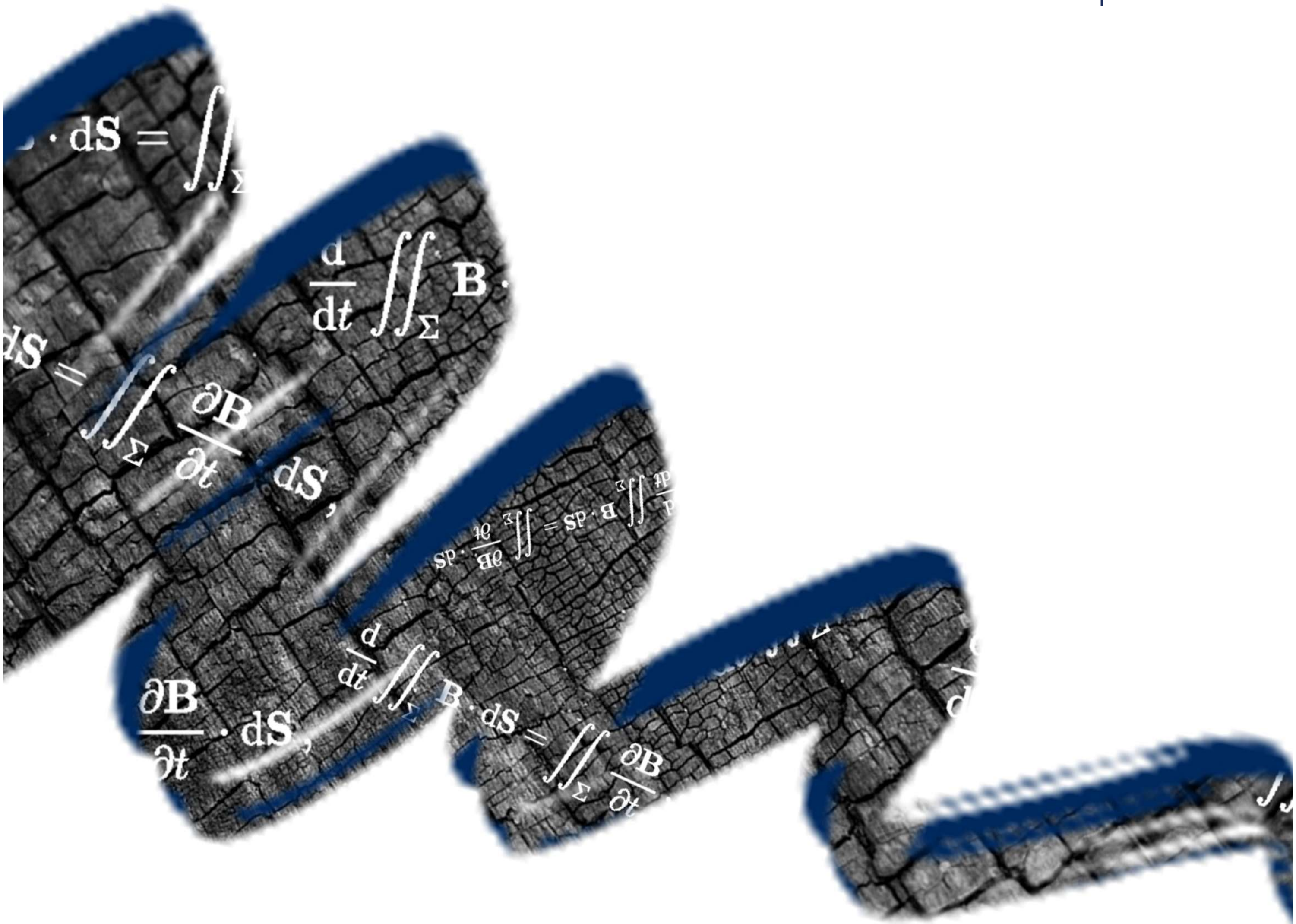
Table A2 Nationally determined contributions (NDC) by end user countries

Destination Country	Paris signatory (Y/N)	Nationally Determined Contribution
Japan	Y	Emissions reduction target of 40% from 2018 levels by 2030 and net zero by 2050. Plans to phase down coal-fired power, transition aged coal plants to LNG, increase solar and wind capacity, and use electric furnaces in steelmaking.
Europe	Y	Reduce net GHG by 55% below 1990 levels by 2030. Net zero by 2050
India	Y	Emissions intensity of GDP to be reduced by 45% by 2030 from 2005 levels. 50% of installed power capacity to come from non-fossil sources by 2030. Additional carbon sink of 2.5-3 billion tonnes CO_2 equivalent via afforestation. Seeks international support for technology transfer and financing. Net zero by 2070.
Vietnam	Y	An economy wide greenhouse gas reduction target of 15.8% by 2030 compared with the projected business as usual pathway using domestic resources, increasing to 43.5% by 2030 with international support, and an intention to achieve net zero emissions by 2050. Includes a commitment to reduce methane emissions by 30% by 2030 compared with 2020 levels, and to rapidly reduce fossil energy use, particularly coal fired power.
Brazil	Y	Targets a 43% reduction by 2030 and 59-67% by 2035, relative to 2005 levels. Net zero by 2050.

APPENDIX B FUGITIVE EMISSIONS COMPLIANCE ASSESSMENT: ISAAC PLAINS COMPLEX. COALBED ENERGY

FUGITIVE EMISSIONS COMPLIANCE ASSESSMENT

For Stanmore Resources Ltd – Isaac Plains Complex



FUGITIVE EMISSIONS COMPLIANCE ASSESSMENT

For Stanmore Resources Ltd – Isaac Plains Complex

PREPARED BY
Scott Thomson, B. Sc., M. Sc., M.B.A. (Tech. Man.)
Managing Director,
CoalBed Energy Consultants Pty Limited

Duncan Thomson, B. Sc., M. Eng.
Technical Director,
CoalBed Energy Consultants Pty Limited

TUESDAY, 25 NOVEMBER 2025

DRAFT REPORT

FUGITIVE EMISSIONS COMPLIANCE ASSESSMENT

For Stanmore Resources Ltd
Isaac Plains Complex

Coalbed Energy Consultants Pty Limited

ABN: 28 142 920 714F

Level 9, 1 York Street, Sydney, NSW, 2000

www.coalbed.com.au

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EXECUTIVE SUMMARY

Stanmore Resources Ltd (Stanmore), through wholly owned subsidiary entities, operates the open-cut coal mine Isaac Plains Complex (IPC) in the Bowen Basin, QLD. IPC comprises Isaac Plains Mine (IPM), Isaac Downs Mine (IDM) and the proposed Isaac Downs Extension (IDE) Project (the Project). IPC has undertaken coal seam gas studies at its open-cut operations to assess long-term fugitive emissions. The intent of this report is to review the existing database to ensure compliance with the National Greenhouse and Energy Reporting (NGER) guidelines and to identify any shortcomings. If non-compliance is identified, CoalBed Energy Consultants (CoalBed) will design a work program to address the outstanding issues. The reporting process aims to comply with the guiding principles set out by the Federal Government National Greenhouse and Energy Reporting (Measurement) Determination 2008 (No. 1).

A detailed guideline document for fugitive emissions reporting (designed to be an attachment to NGER) has been completed through ACARP project C20005. This document has provided a reference framework for this report.

To comply with the NGER determination, emissions estimates must be:

(a) transparent — emission estimates must be documented and verifiable;

(b) comparable — emission estimates using a particular method and produced by a registered corporation in an industry sector must be comparable with emission estimates produced by similar corporations;

(c) accurate — uncertainties in emission estimates must be minimised and any estimates must be reported 'at the 95% confidence interval'; and

(d) complete — all identifiable emission sources must be accounted (demonstrate lack of bias, sample sufficiency and uncertainty).

IPC has a total of 18 borehole sites, including five (5) within the IDE Project area, containing gas data available to complete this report. All work was conducted in accordance with industry standards (in particular, gas content and gas composition testing were undertaken in reference to Australian Standard 3980 and International Standard ASTM D1945-03/ISO6976).

The gas data underwent a systematic data validation process, and some data were removed due to:

- Leakage of the canister;
- Missing Q1 (lost gas) data;
- The presence of non-gas-bearing clastic rock types; and
- Abnormal volatiles, ash and/or density.

Investigations revealed the existence of a single distinct gas domain:

- **Domain 1**: The 'standard' for IPC – low gas to 100m depth, followed by a rapid ramp up in gas content from 100-200m, followed by a decreased gradient of increase from 200m+. Methane[1] dominates as the primary gas from 75m+. This domain was identified in all valid boreholes.

Sample sufficiency and uncertainty were found to be adequate for Domain 1. A total of three (3) boreholes, including at least one (1) 'Type' borehole, must be drilled for each gas domain to meet the minimum requirements as stated in the Guidelines.

Using the available datasets, gas content calculations for IPC were produced using a SAS LOESS procedure. SAS LOESS implements a nonparametric method for estimating depth-relevant regression surfaces. Gas composition (using the CH_4:CO_2 ratio after N_2 is removed – expressed as a percentage) was also calculated with the SAS LOESS method. The table below (for further context see Table 2, p42) outlines the key findings of this report[2,3]:

[1] *The terms methane and CH_4 are used interchangeably in this report.*
[2] *The calculated CO_2-e values should only be applied to a maximum depth of 300m for Domain 1.*
[3] *CO_2-e tonnes are calculated using a global warming potential value of 28 for methane and 1 for carbon dioxide.*

Table 2 (page 42): Summary of CO_2-e estimates for IPC[4,5].

Depth Interval	No. of Samples	Gas Content (m^3/t)	CH_4 (Ratio)	CO_2 (Ratio)	CO_2-e (kg/t) as a Function of CH_4	CO_2-e (kg/t) as a Function of CO_2	TOTAL CO_2-e (kg/t)	TOTAL CO_2-e (t/t)
0 to 25m	1	0.00	0.09	0.91	0.00	0.00	0.00	0.00000
25 to 50m	3	0.61	0.36	0.64	4.12	0.73	4.86	0.00486
50 to 75m	30	0.99	0.26	0.74	4.96	1.36	6.32	0.00632
75 to 100m	19	1.94	0.78	0.22	28.65	0.80	29.44	0.02944
100 to 125m	6	3.34	0.89	0.11	56.69	0.65	57.34	0.05734
125 to 150m	12	3.88	0.99	0.01	72.91	0.08	72.99	0.07299
150 to 175m	5	4.34	0.99	0.01	81.64	0.08	81.72	0.08172
175 to 200m	3	4.95	0.99	0.01	93.48	0.05	93.52	0.09352
200 to 225m	4	5.19	1.00	0.00	98.12	0.04	98.16	0.09816
225 to 250m	0	5.34	0.99	0.01	100.77	0.06	100.83	0.10083
250 to 275m	8	5.55	0.99	0.01	104.64	0.08	104.72	0.10472
275 to 300m	6	5.77	1.00	0.00	109.20	0.04	109.24	0.10924
300 to 325m	0	5.99	1.00	0.00	113.30	0.04	113.34	0.11334
325 to 350m	0	6.22	1.00	0.00	117.55	0.06	117.61	0.11761
350 to 375m	0	6.45	0.99	0.01	121.79	0.07	121.86	0.12186
375 to 400m	0	6.68	0.99	0.01	126.02	0.09	126.10	0.12610
400 to 425m	0	6.91	0.99	0.01	130.23	0.11	130.34	0.13034
425 to 450m	1	7.14	0.99	0.01	134.34	0.12	134.47	0.13447
450 to 475m	0	7.38	0.99	0.01	138.63	0.14	138.77	0.13877
475 to 500m	1	7.51	0.99	0.01	141.05	0.16	141.20	0.14120
500 to 525m	1	7.85	0.99	0.01	147.16	0.19	147.35	0.14735
525 to 550m	0	8.07	0.99	0.01	151.13	0.21	151.35	0.15135
550 to 575m	1	8.36	0.98	0.02	156.25	0.24	156.49	0.15649
575 to 600m	0	8.53	0.98	0.02	159.40	0.26	159.66	0.15966
600 to 625m	1	8.86	0.98	0.02	165.17	0.31	165.47	0.16547
625 to 650m	2	9.04	0.98	0.02	168.42	0.33	168.75	0.16875

The result is a calculated gas content and gas composition for zoned depth intervals, which can then be used to determine a CO_2-e value for seams mined from the

[4] *Columns 3-8 have been rounded to two decimal places for presentation purposes.*
[5] *m^3/t = cubic metres per tonne, kg/t = kilograms per tonne and t/t = tonne per tonne.*

corresponding zone. IPC may then multiply this CO_2-e value by the in-situ tonnes of a particular zone to calculate potential fugitive emissions on an annual basis using the mine model. This approach also enables IPC to predict future fugitive emissions by integrating mine shell profiles and the emissions model.

1. INTRODUCTION

This report is provided for the purposes of producing a coal mine gas assignment model and fugitive emissions estimation in accordance with the Federal Government's National Greenhouse and Energy Reporting framework.

The *National Greenhouse and Energy Reporting Act 2007* (the "NGER Act 2007"), establishes this framework with several supporting legislative instruments, including the *National Greenhouse and Energy Reporting Regulations 2007* and the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* (the "Determination"). Annual reporting of greenhouse gas emissions and energy use is required, including the estimation of fugitive emissions from coal mining operations.

For fugitive emissions from open-cut coal mining, several measurement methods are available, including statistically valid gas sampling of the gas reservoir in the mining area. In support of this method, the Australian Coal Association Research Program ("ACARP") published an industry guideline that provides a framework for measuring, estimating, and reporting fugitive emissions from open-cut mines.

The Determination now incorporates relevant parts of these ACARP Guidelines (titled "Project C20005: Guidelines for the Implementation of NGER Method 2 or 3 for Open Cut Coal Mine Fugitive GHG Emissions Reporting"[6]), including the requirement for a qualified Estimator to produce a statistically valid gas assignment model.

This report is based on unbiased, representative gas sampling of the gas-bearing strata in the IPC mining area. It is entirely based on robust, stringent gas sampling, together with a professional assessment of the mine's relevant geology. This is an evidence-based report for the purposes of assessing statutory reporting obligations.

The mine is situated near the town of Moranbah in the Bowen Basin, QLD (Figure 1).

[6] *ACARP C20005, Guidelines for the Implementation of NGER Method 2 and 3 for Open Cut Coal Mine Fugitive GHG Emissions Reporting, December 2011.*

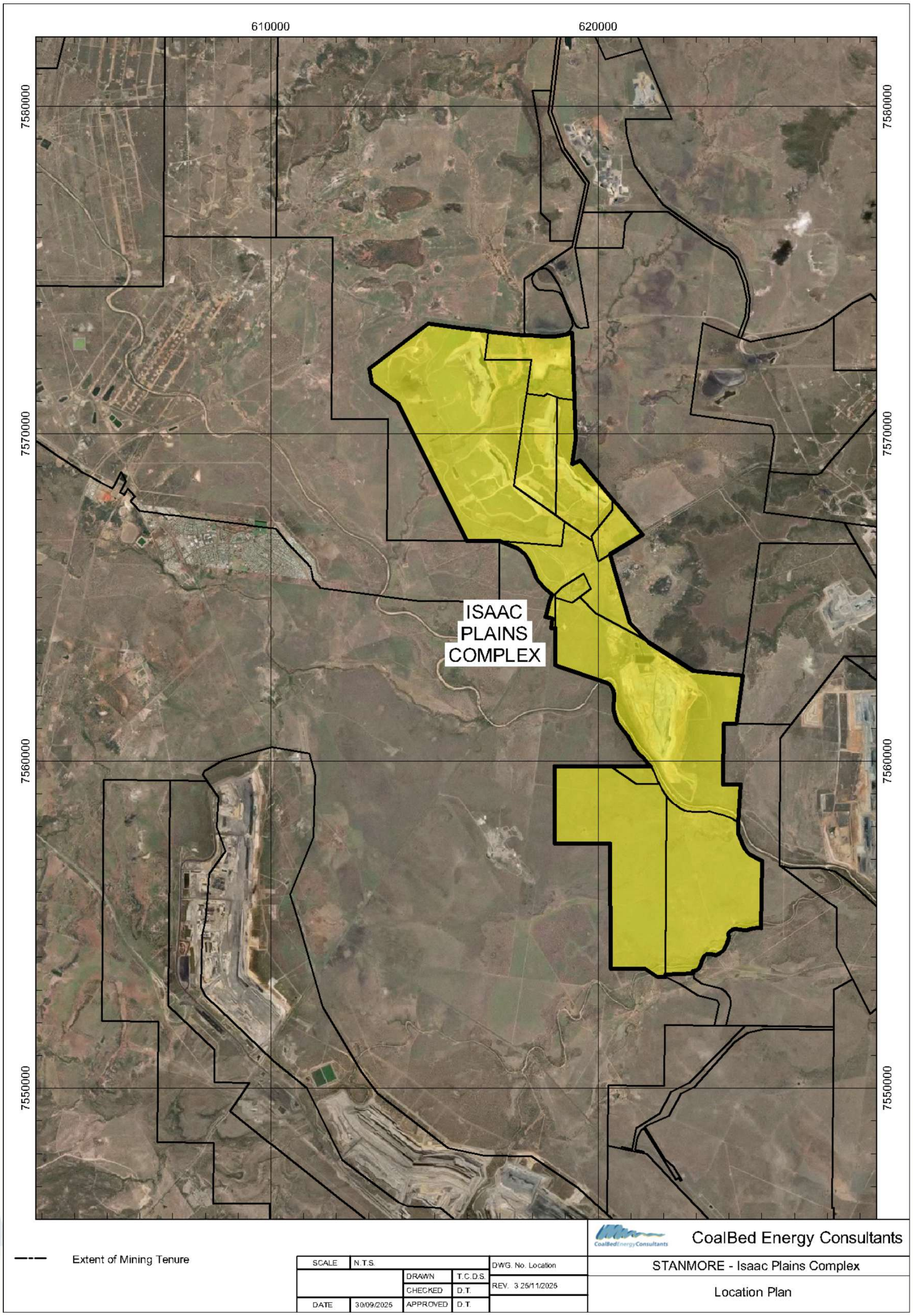
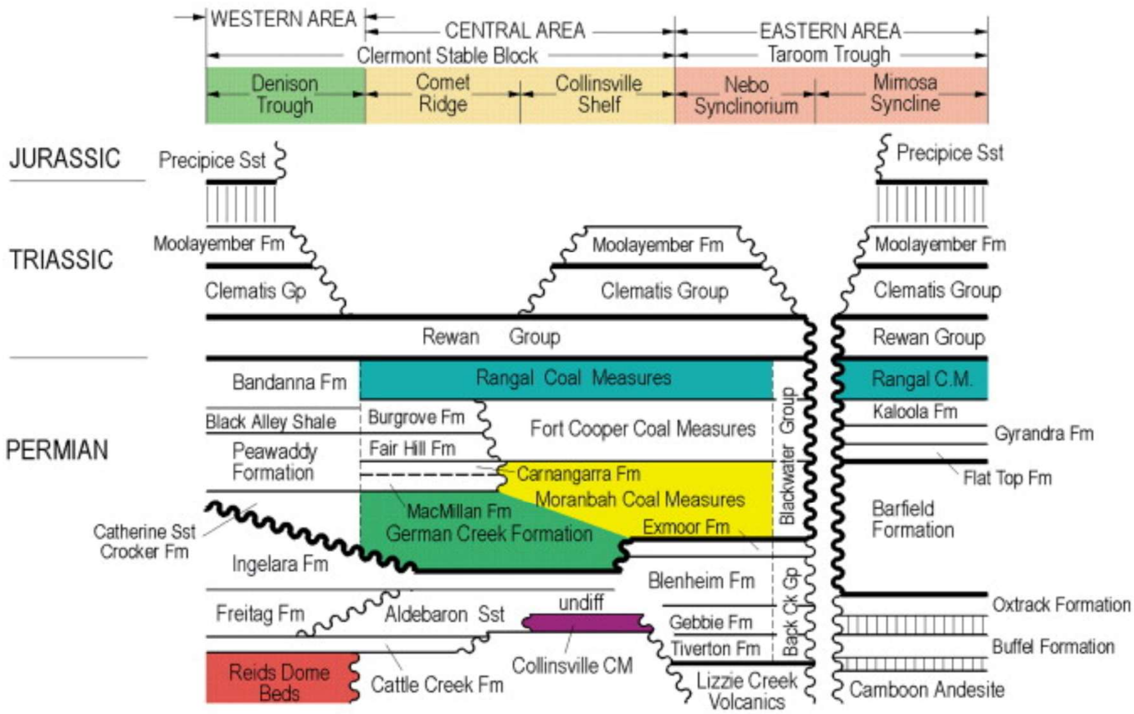


Figure 1: Location of IPC.

The project area is in the Bowen Basin, QLD. The general stratigraphy of the mine is summarised in Figure 2.



Source: Modified from Beeston, 1986

Figure 2: General stratigraphy at IPC.

The National Greenhouse and Energy Reporting Determination 2008 sets out the methods that may be used to estimate fugitive emissions from an open-cut coal mine. There are four (4) methods available, they are:

- Method 1 – The State (QLD) default emission factor of 0.031, which is multiplied by the run-of-mine (ROM) tonnes;
- Method 2 – Estimation of the gas in place using site-based gas data that has been collected according to industry standard methodologies;
- Method 3 – Estimation of the gas in place using site-based gas data that has been collected according to Australian and International standard methodologies; and
- Method 4 – Not applicable to open cut mining.

The question has been posed as to whether the historical gas sampling exploration program has the potential to estimate fugitive emission liability for IPC and enable annual reporting in line with National Greenhouse and Energy Reporting (NGER) guidelines using 'Method 2 / Method 3'[7]. The aim is that the sampling and reporting approaches (detailed herein) comply with the guiding principles set out by the National Greenhouse and Energy Reporting (Measurement) Determination 2008 (No. 1) under the NGER Act.

A detailed guideline document for fugitive emissions reporting (designed to be an attachment to NGER) has been published (through ACARP project C20005). This document provides a reference framework for this assessment.

Stanmore has provided detailed maps, geological data and all gas testing results from exploration drilling carried out as part of this assessment. A total of 18 boreholes constitutes the base information used for this study.

It is acknowledged that developing an emissions model is an iterative process, and that this report reflects the position as it stands at the time of reporting, consistent with the existing data. Additional information may be added as mining progresses, and the model will be updated accordingly.

[7] *The available methods include Method 1 (default) through to Method 4 (direct measurement). A selected method must be used for a minimum of four (4) reporting years, unless replaced by a 'higher' method.*

2. BACKGROUND TO NGER REPORTING PROCESS

2.1 GENERAL TENETS

The National Greenhouse and Energy Reporting (NGER) Act 2007 was introduced to establish a national reporting framework to assist with preparations for estimating and subsequently reducing CO_2 emissions in line with international commitments at the time.

To comply with the NGER determination, emissions estimates must be prepared in accordance with the following principles[8]:

(a) transparency — emission estimates must be documented and verifiable; (including sampling and testing procedures, interpretation and estimation methodology, and assumptions);

(b) comparability — emission estimates using a particular method and produced by a registered corporation in an industry sector must be comparable with emission estimates produced by similar corporations in that industry sector using the same method and consistent with the emission estimates published by the Department in the National Greenhouse Accounts; (document procedures and guidelines for sampling, testing and reporting with particular reference to reporting bases for coal and gas);

(c) accuracy — having regard to the availability of reasonable resources by a registered corporation and the requirements of this Determination, uncertainties in emission estimates must be minimised and any estimates must be reported 'at the 95% confidence interval' (document datasets and methods used to make the estimates); and

(d) completeness — all identifiable emission sources within the energy, industrial process and waste sectors as identified by the National Inventory Report must be accounted (demonstrate lack of bias, sample sufficiency and uncertainty).

The ACARP guidelines have been used as the basis for structuring this report and should be consulted for further background information (see ACARP Project C20005). In particular, the following flowchart (Figure 3) captures the key components of this process, which have been (in essence), adopted for this project. The exploration drilling process to collect gas data is presented in Figure 4.

[8] *Division 1.2.1.13 of NGER Determination- General principles for measuring emissions.*

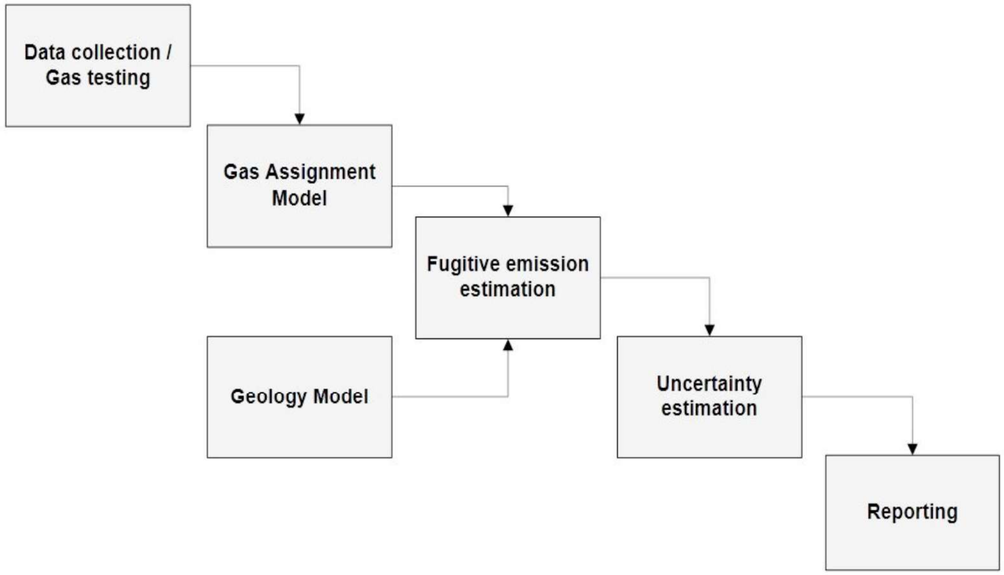


Figure 3: Emissions estimation flowchart (from ACARP Project C20005).

For NGER compliance, the following is deemed to be required:

- Validation of test results, QA / QC of all data;
- Characterise reservoir & determine spatial variability;
- Identification of domains, if present;
- Assess uncertainty levels;
- Develop database;
- Construct static reservoir model; and
- Report to the NGER officer.

The procedure detailed in this report conforms to "Method 2", namely, using site-specific measurement data collected and processed in line with industry-standard methodologies.

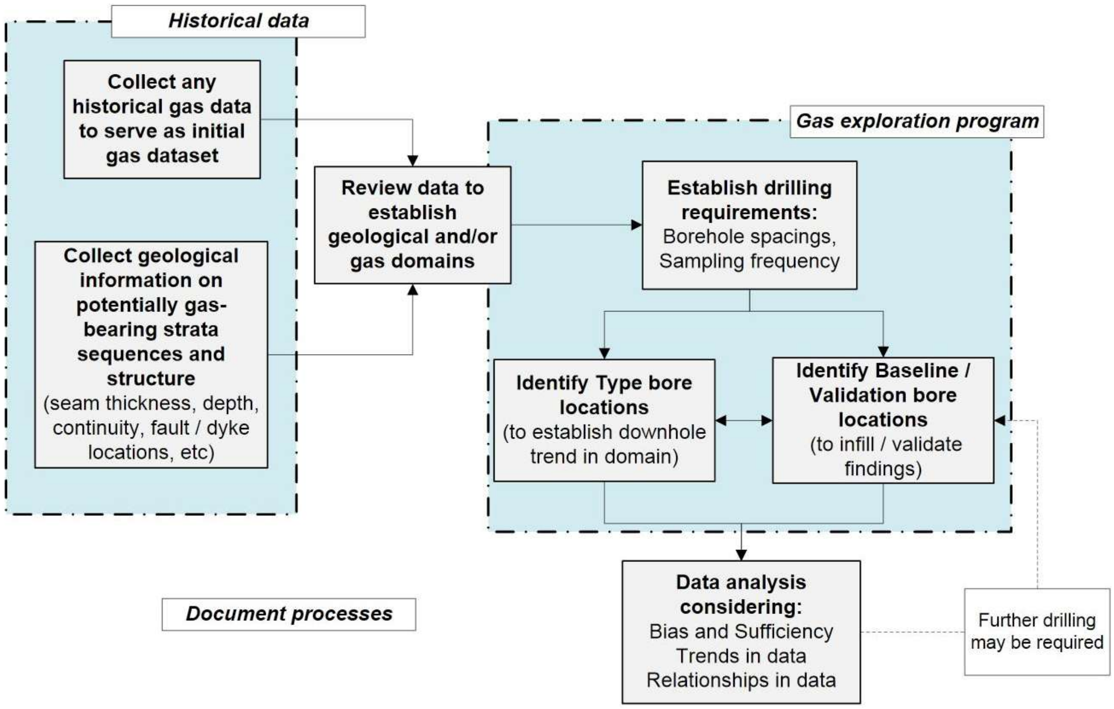


Figure 4: *Summary of the process for Gas in Place estimation (from ACARP Project C20005).*

2.2 QUALIFICATIONS OF ESTIMATOR

The Estimator is a person meeting the minimum qualifications described below. The Estimator is the individual who is appointed by the company to estimate the fugitive emissions from an open-cut coal mine.

The minimum qualifications of an Estimator are:

- Minimum of five (5) years' experience in the assessment of coal deposit continuity and dimensions, including the identification of geological features that affect coal seam geometry such as seam splitting, subcrop lines, washouts, and otherwise deterioration in thickness of the coal seams, including (but not limited to) the presence of any adverse structural features (for example faults, folds or igneous intrusions);
- Appropriate experience with coal seam gas parameters such as gas content, composition, saturation, and any other parameter as applicable, and how the distribution of these parameters relates to the geology at a mine site being assessed. It is expected that 'appropriate experience' comprises a minimum of one (1) year of practical coal seam gas interpretation experience and estimation of Gas in Place either for mine gas management or commercial extraction, and/or formal education in coal gas concepts via an industry recognised course provider; and

- Sufficient exposure to geological resource modelling or consideration of extrapolation concepts, particularly in determining the adequate number of boreholes and sampling intervals.

The Estimator can be internal or external to a company, but must possess the skill sets listed above. A transparent and auditable process must be put in place. The resulting estimation must demonstrate due diligence and independent peer review of process and data. Peer review may be undertaken by an employee of the same company[9].

In this case, CoalBed Energy Consultants (CoalBed) is acting as Estimators for Stanmore. CoalBed has considerable experience in Coal Seam Gas (CSG), Coal Mine Methane (CMM) and coal mining activities. The company has been at the forefront of developments in Australian gas drainage, advanced directional drilling practices and fugitive emission studies since its inception in 1998. CoalBed has project-managed and advised on CSG projects, as well as on surface and underground gas-gathering and utilisation programs for mining. The company has been involved in technical due diligence for clients in Australia and overseas, including major international corporations. In addition, CoalBed provides technical training in CSG and CMM to many companies and institutions.

CoalBed has been involved in fugitive emission studies for Australian coal mining companies since 2007. The principal author of this report (as well as the Managing Director of CoalBed) is Mr Scott Thomson (B.Sc., M.Sc., M.B.A.). Mr Thomson has more than 50 years' experience in the mining and energy sectors, including working as a mine geologist for major corporations involved in resource assessments and exploration management. He has worked as a private consultant in the resource industry since 1998, specialising in coal seam gas and technology development. Over the past 25 years, his focus has been on private consulting and research activities related to coal seam gas, geology, and drilling technology. Mr Thomson has authored many papers, conducted seminars on the subject, and has completed many Independent Expert Reports for ASX Release and due diligence studies on coal seam gas-related issues.

Duncan Thomson (B.Sc., M. Mining Eng.) is also a Director of CoalBed and a co-author of this report. Duncan has practical hands-on project management experience in CSG and mining and has specialised in drilling and gas for the last 25 years. Duncan joined CoalBed in 2008 and became a Director in 2010. He has project-managed CSG exploration and mining projects in the major Australian coal basins. Duncan has experience in coal seam geology, coal mining, exploration, coal seam gas, geotechnical engineering and project management. Duncan holds a BSc in Geology from the University of Newcastle and a Masters of Mining Engineering from the University of NSW.

[9] *In this case, CoalBed has completed an internal peer review between its directors.*

CoalBed runs public and in-house training courses in 'Coal Seam Gas Fundamentals', 'Drilling for Gas Projects', 'Production and Completion Methodologies' and 'Turning Resources into Reserves'. Attendees are drawn from major corporations, government agencies, the finance sector and junior explorers.

3. DATA COLLECTION GAS TESTING

3.1 GATHERED FUGITIVE EMISSIONS SPECIFIC DATA

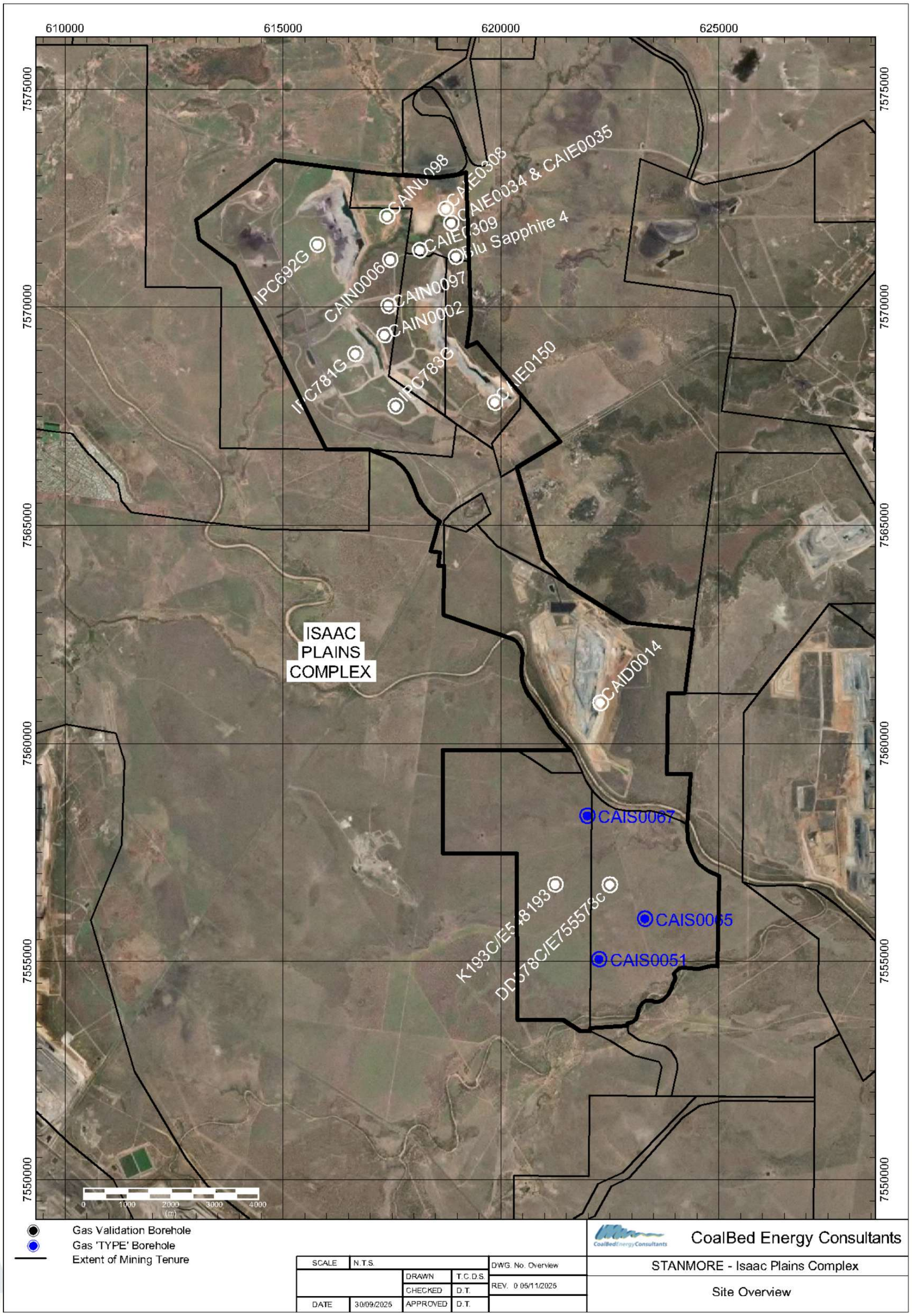
IPC has 18 borehole sites, of which five (5) are in the IDE Project area, with fugitive emission gas sampling data (Figure 5). Site-based staff planned and managed the assessment, which was implemented in association with several laboratories that independently completed the gas testing (Appendix I). The laboratory work was conducted according to industry standards (in particular, gas content and gas composition sampling were undertaken in accordance with Australian Standard 3980[10] and International Standards ASTM D1945-03/ISO6976, respectively).

These borehole sites were selected to representatively sample throughout the IPC mining leases, including the IDE Project mining lease application areas (spatial sampling designed to be regularly spaced and representative) and in accessible areas away from historic mining activities (where possible).

All three (3) of the recent 2025 gas exploration boreholes, which are located in the IDE Project area, are classified as 'Type' as per the definition in the ACARP Guidelines (Appendix II). Three (3) boreholes, including a 'Type', must be drilled for each gas domain to meet the minimum requirements as stated in the Guidelines. A 'Type' borehole must sample all potentially gas-bearing strata with a relative density (RD) of <1.95g/cc and a thickness of >0.5m[11].

The current dataset contains 17 valid gas boreholes (one (1) failed CoalBed's internal QA/QC and validation checks). Together, they comprise a single distinct gas domain at IPC. This gas sampling program identified Domain 1 with all 104 valid samples.

[10] *The Estimators assume that all laboratory work has been carried out as reported. The QA / QC methods of the laboratory are contained in their reports to Stanmore and not discussed herein.*
[11] *Gas bearing strata within the weathered zone were not considered to be part of the required testing interval for 'type' boreholes.*



<u>Figure 5</u>: The location of the 18 boreholes used in this study. Note that one (1) borehole (CAIN0098) failed CoalBed's QA/QC and validation process and was, therefore, removed from the dataset.

The average spacing between the gas boreholes in IPC is approximately one (1) km, which, in our estimation, is sufficient.

The commercial CSG industry provides an analogue. For example, in a typical CSG field, exploration wells are generally widespread, with approximately one (1) well per 30 km^2, depending on the area. If potential commercial quantities of gas are identified, additional drilling is undertaken in the area until full-scale production is established. Production wells are generally spaced at some 600m–1200m or more. Boreholes utilised for this reservoir assessment should align with these commercial CSG operation requirements (in many cases, they already exceed the spacing in a production field).

3.2 DATA VALIDATION

CoalBed investigated the relationship between gas distribution and geology, gas content, ash, and relative density. This data validation process requires a review of supplied information for internal consistency. Data may be rejected if the following occurs:

- Leakage of the canister;
- Inaccuracies in gas composition data;
- Evidence of coal with abnormal volatile matter;
- Sampling error, between sub-samples taken from the same seam;
- Abnormal gas content results (with reference to depth); and
- Identification of non-gas-bearing clastic rock types.

During our investigations, the following procedure was applied in our test validations:

- Check that reporting bases are consistent[12]:
  - Do they conform to Australian Standard 3980? Although it is beyond this assessment's scope to audit the laboratory's data procedures, all gas data has been reported to comply with the Australian Standard, and the issuing laboratories are reputable and experienced. On that basis, it is assumed that the data comply with the Guideline requirements.
  - All data have been reported at 20 degrees C and 101.3 kPa (atmospheric). Data has been subsequently converted to the preferred

[12] *"Sample corrected data" (as referenced herein) is sample data which has been adjusted to an average sample density; converted to international reporting standards for temperature / pressure; and corrected to insitu moisture (for gas content).*

NGER base of 15 degrees C and 101.3 kPa using the formula provided in the ACARP Guideline (see p27, Appendix 3, ACARP Report C20005).

- All data has been corrected to a common density (an average of all RD values in the database), namely 1.52g/cc[13].
- All boreholes were located in areas away from existing mining activities. Therefore, all depth data is based on pre-mining relative levels (RL's).
- All gas contents have been corrected from sample moisture to in-situ moisture. An in-situ moisture of 6.36% has been calculated by the Estimators for this report[14].

To complete the data validation process, the following steps have been undertaken, and suspect data has been excluded from the database:

- Leakage of the canister, which may be expressed in high (abnormal) N_2 values. When a canister leaks between the time of sealing and receipt of the desorption sample in the laboratory, a disproportionately high IDR_{30} (when compared to the corresponding value of Qm) can be identified. This method identified zero (0) samples that may have leaked.
- Inaccuracies in gas composition data. This is particularly problematic in low-gas-content measurements[15]. For all subsequent gas content calculations, CoalBed utilised a CH_4:CO_2 ratio, which removed all N_2 contamination from the results and is expressed as a relative percentage. The association of high N_2 with low gas content results is, in our view as Estimators, most likely due to air contamination of low-volume samples. The argument that N_2 is "real" is speculative at best, and a significant body of evidence suggests otherwise. We consider that treating N_2 as "real" risks underestimation of emissions, and we take the conservative view that a ratio of CH_4:CO_2 more accurately represents the true gas composition of the coal in-situ. Evidence supporting the rejection of N_2 in low gas content coals (as a consequence of air contamination) is not limited to, but includes:
    - In Australian underground coal mining and in CSG production very little N_2 (2-6% maximum by volume) is reported either in production gas or in samples from exploration or mining activities;

[13] *No density data was provided for the CSG Sapphire-4 borehole drilled by Blue Energy. Therefore, the average of 1.48g/cc was applied to this dataset.*

[14] *See ACARP Report C10041.*

[15] *The generic and subjective term 'low gas', is used commonly in coal mining, and pertains to gas contents that are usually less than ~2m^3/t. However, the 'Low Gas Zone' refers particularly to the strict definition applied in the ACARP Guidelines.*

- International CSG experience confirms this observation, for example see Moore, 2012[16], "… *in some cases, O_2 may react with the coal itself and be preferentially adsorbed, with the effect of leaving excess N_2 in the gas mixture (Creedy and Pritchard, 1983; Havton, 2003; Jin et al., 2010). It is important that this relic N_2 is not mistaken as being inherent within the seam*";
- The theoretical origin of N_2 in coal seams occurs through thermogenic processes (see Hunt 1979[17]). It is not plausible that N_2 from this source should occur in the shallow sub-surface and be absent at depth;
- CoalBed has a database of many thousands of gas content/composition samples from Australian and international coal basins. The relationship between high N_2 values and low gas content results is unequivocal and independent of depth (Figure 6). Samples at depths exceeding 300m may have high N_2 but only when accompanied by very low gas content results (e.g., <1m^3/t);
- The relative shapes of the isotherms for CH_4, CO_2, and N_2 imply that N_2 would be the first gas to escape during depressurisation. It is counterintuitive that N_2 remains in low gas content coals, whereas CH_4 has desorbed, and CO_2 is retained; and
- The possibility that N_2 is a product of biogenic activity in the shallow sub-surface is rejected as a) rarely does methane occur with the high N_2 (CH_4 is a known product of biogenic activity) and b) work by the CSIRO has established that N_2 is consumed rather than produced in biogenic activity in coals (Saghafi et al, 2012[18]).

[16] *Moore, T., 2012. Coalbed methane: A review, International Journal of Coal Geology 101 (2012) 36–81.*
[17] *Hunt, J.M., 1979. Petroleum Geochemistry and Geology. Freeman & Co., San Francisco, 617 pp.*
[18] *Saghafi, K. Pinetown, D. J. Midgley, A. S. Andrew, H. Javanmard, D. Liitrogencontent, CSIRO ePublish number EP124846 / 22 October 2012, ACARP Project C19003.*

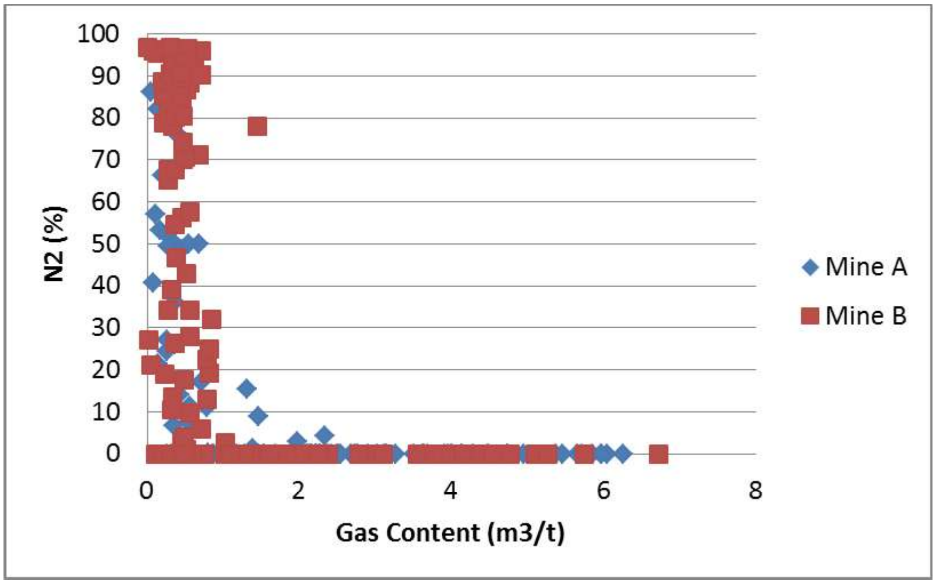


Figure 6: N_2 (%) versus raw gas content (m^3/t) at two (2) mine sites. Many of the high N_2 results shown above occur at depths exceeding 100m. The pattern illustrated is consistent with both Australian and international experience. It is likely that not enough gas is given off in low gas content results to complete laboratory purging processes, and therefore, high N_2 values are reported.

- Evidence of coal with abnormal volatile matter (possible devolatilisation). This is due to proximal igneous activity that has altered the coal's material properties. This local effect should be discounted from regional trends extrapolated from gas data. To identify possible devolatised coal, CoalBed compared volatile matter to ash, with zero (0) historic samples being recognised as abnormal.
- Evidence of sampling error emerges, including inconsistencies in gas content test results and proximate analysis results between sub-samples taken from the same seam. CoalBed also completed a seam-to-seam and borehole-to-borehole comparison of all samples. A total of five (5) samples were identified as abnormal and removed from the database (primarily for Q1 errors).
- Abnormal gas content results. This process involved trending gas contents measured with depth for each borehole. This investigation identified zero (0) results to be invalid.
- Samples from the 'weathered zone' do not represent virgin conditions and were removed from the dataset. No samples were identified as invalid due to moisture.

- A 1.95 g/cc density limit is applied (as per the ACARP guidelines[19]) as the 'boundary' between gas-bearing strata and non-gas-bearing clastic rock types. Samples with a density of >1.95 g/cc (i.e. 'stone') are not discarded from the dataset (as the results are justifiable and pass the validation testing process). However, these samples are irrelevant for fugitive emission estimates (i.e., they are assigned 'zero gas') and are therefore not included in subsequent figures, emission calculations, or this report. Additional samples are also removed if inconsistencies are observed in the density versus ash ratio. A total of 13 samples were removed from the dataset as 'stone' or invalid density/ash.

Table 1 (below) details the gas sample results and identifies the rejected samples and the reason why.

Table 1: Database validation summary for IPC.

Work Programs		*Errant Samples*						*Valid Results*
Laboratory	**Total Samples Collected**	**Devolatisation**	**Density Limit**	**Sample Error**	**Gas Content Sample Error**	**Canister Leakage**	**Weathered Zone**	**Content / Composition Samples**
See Reports	122	0	13	5	0	0	0	**104**

[19] *Technical Discussion of the Implementation of NGER Method 2 or 3 for Open Cut Coal Mine Fugitive GHG Emission Reporting, ACARP project C20005, Burra, A. and Esterle. J., December 2011.*

4. DATA ANALYSIS AND INTERPRETATION

4.1 SPATIAL TRENDS, IDENTIFICATION OF DOMAINS

Domains are defined as areas of common characteristics of "one or more parameters" (ACARP C20005 Guideline) in which gas relationships appear to follow a consistent pattern of gas content and/or composition.

Our work has identified one (1) distinct gas domain at IPC (Figure 7):

- **Domain 1**: The 'standard' for IPC – low gas to 100m depth, followed by a rapid ramp up in gas content from 100-200m, followed by a decreased gradient of increase from 200m+. Methane dominates as the primary gas from 75m+. This domain was identified in all valid boreholes.

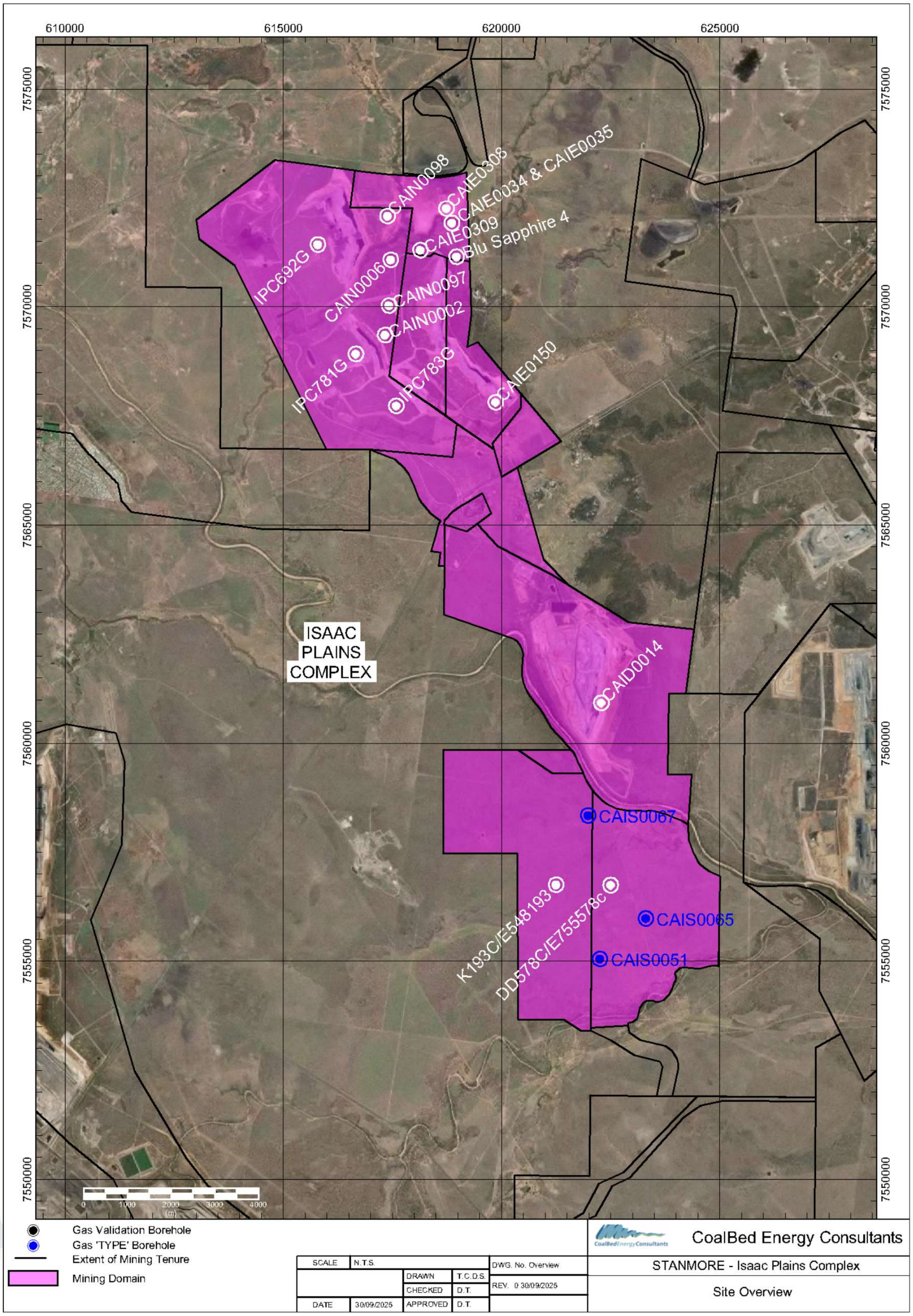


Figure 7: The extent of Domain 1, as identified at IPC.

4.2 DOMAIN 1 RESERVOIR CHARACTER

For IPC, the 'standard' gas profile versus depth is effectively 'low gas' to around 100m, followed by a rapid ramp-up from 100m to 200m, then a decreasing gradient of increase from 200m+. This is a common pattern for Bowen Basin coals (also the Sydney Basin); and has been documented elsewhere (see Thomson et al, 2008[20], and Thomson, 2010[21]).

The profile described above is the basis for designation as "**Domain 1**". It is a common trend and is effectively present in all 17 boreholes under investigation (Figure 8).

Domain 1 gas composition is dominated by methane with increasing depth. CO_2 was only found in the very shallow strata (Figure 9).

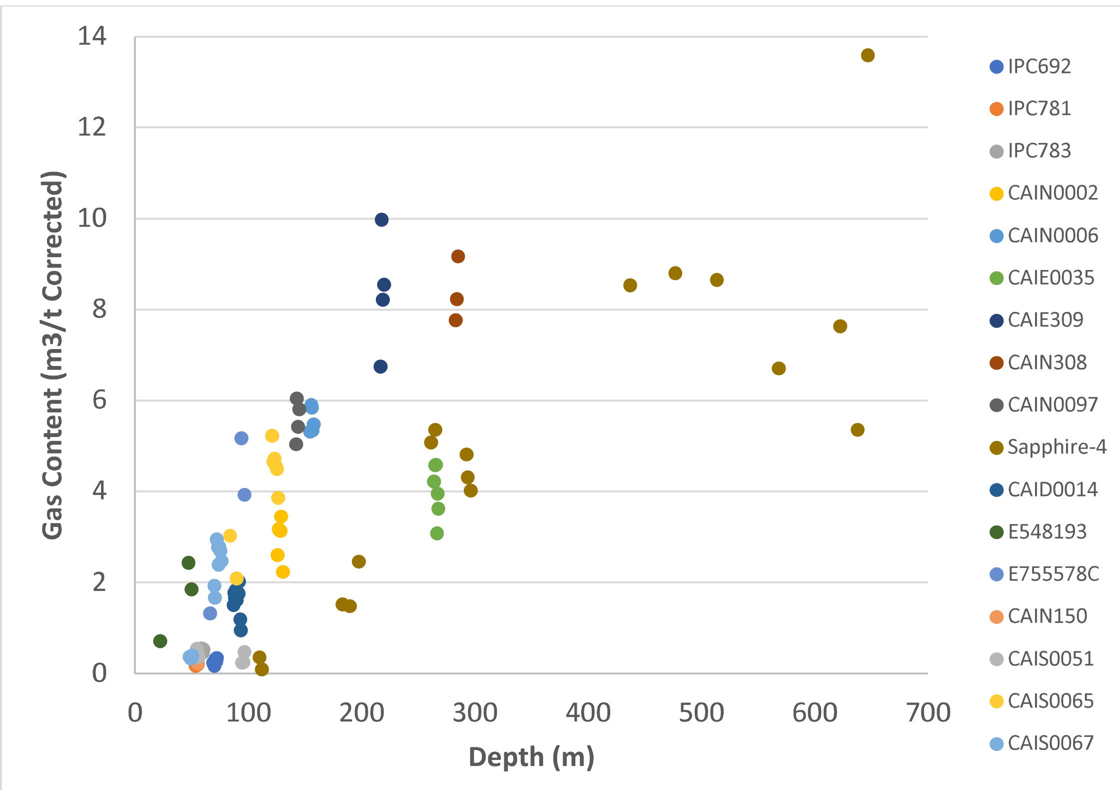
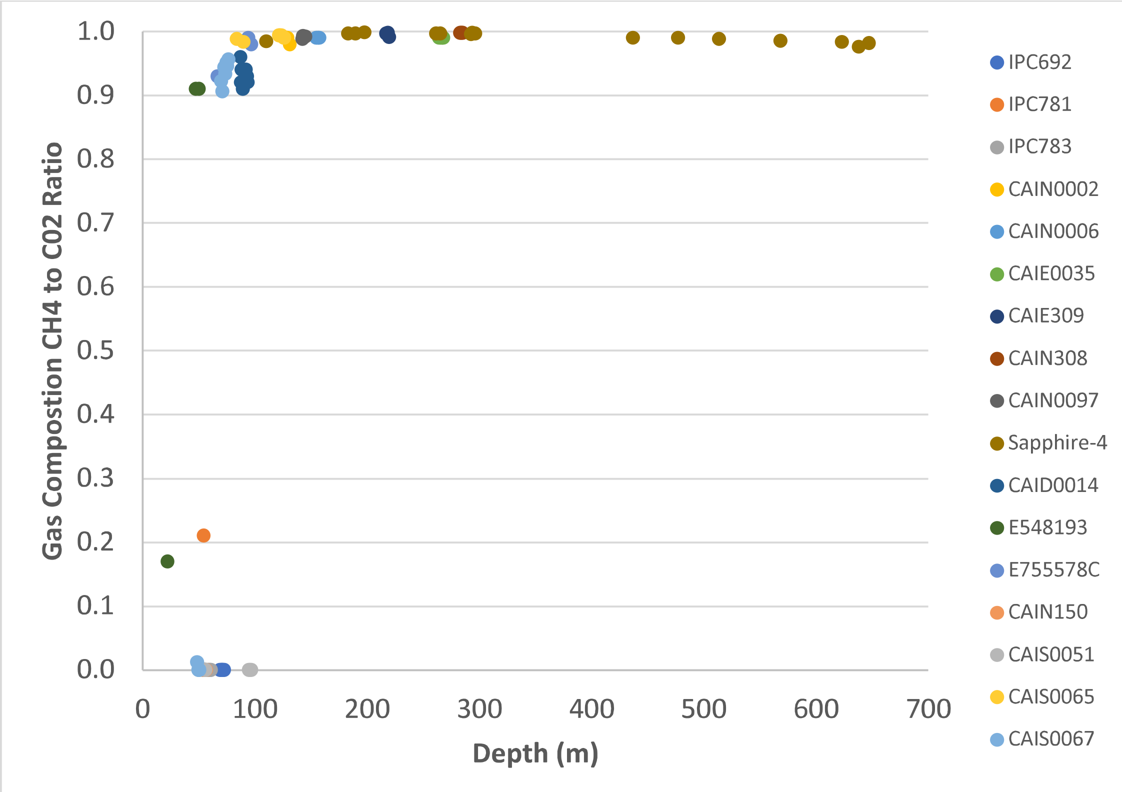


Figure 8: The 'standard' Domain 1 gas profile for IPC (sample corrected data – refer to Section 3.2).

[20] *Thomson, S., Hatherly, P., Hennings, S., and Sandford, J., 2008. A Model for Gas Distribution in coals of the Lower Hunter Sydney Basin, Eastern Australian Basins Symposium III Proceedings, Sydney, September 15-17 2008.*

[21] *Thomson, 2010. Gas Layering in the Subsurface: Implications for Greenhouse Gas Emissions, Bowen Basin Symposium Proceedings, Mackay, 2010.*



<u>Figure 9:</u> The Domain 1 gas composition profile, which occurs at IPC (sample corrected data – refer to Section 3.2).

4.3 'LOW GAS ZONE'

The Estimator reviewed all gas boreholes individually to determine the base of the 'Low Gas Zone' at IPC. The 'Low Gas Zone' is defined as strata lacking in quantifiable quantities of CSG (i.e. less than 0.5m^3/t (raw)). This assessment identified significant vertical variations in the trends observed for each borehole and what appears to be a random scatter spatially.

An alternative, more conservative, and recommended approach is to use the SAS LOESS-derived predictive values to estimate emissions in the shallow subsurface, thereby negating the need to produce an irregular 3D surface (which almost certainly does not reflect geological reality) as would otherwise be the case (refer to Table 2). In the authors' opinion, this approach more accurately honours the data, is more conservative and provides a truer representation of the 'Low Gas Zone' as intended by the Guidelines.

5. DATA SUFFICIENCY, UNCERTAINTY AND BIAS

5.1 BIAS

Sampling bias is a type of error that is due to the non-random sampling of the gas-bearing stratigraphy or depth ranges. This may cause some lithologies or areas of the subsurface to be over or underrepresented.

Sample bias analysis is carried out using expert judgement where the Estimator considers and comments on the adequacy of the collected data volumes in relation to the following observations:

- Borehole spacing targets virgin gas areas – i.e. there is no over/under-representation of the shallow or deep parts of the deposit, previously drained areas, or crop lines.

The boreholes at IPC provide an appropriate areal coverage of the lease (see Figure 5 and Figure 7).

- All potentially gas-bearing strata types have been sampled and considered.

Data sampling has been comprehensive and has included the drilling and sampling from several 'Type'[22] borehole.

- Sample frequency for the domain could be improved with the drilling of several new 'Type' boreholes. This will ensure no over/under-representation of the shallow or deep parts of the strata.

Sample frequency for Domain 1 is considered sufficient. There is no evidence that local geology has significantly impacted the IPC gas reservoir (e.g. faults / dykes etc.). It is important to note that additional sampling may be required in the future if any of the pit shells are extended beyond 300m depth or away from the existing dataset.

5.2 UNCERTAINTY

CoalBed has used t-tests to calculate uncertainty for the IPC dataset. A t-test assesses whether the means of groups of data are statistically different from each other or the same population. This type of analysis is appropriate for this assessment, as it allows statistical comparison between individual boreholes. The results of these calculations

[22] *'Type' status of the boreholes has been evaluated by checking the wireline log trace against the sampled intervals.*

(which include mean, standard deviation, degrees of freedom and probability) can be used to determine the uncertainty of a dataset.

Uncertainty analysis of Domain 1 produced an uncertainty figure (at 95% confidence) of 17.12% (based on 104 samples).

5.3 DATA SUFFICIENCY

Data sufficiency refers to the degree of over or under-representation. It is desirable that the range of possible gas-bearing lithologies, depths and domains be sampled, and each relevant subset be suitably represented. This needs to be demonstrated for NGER reporting purposes.

Data sufficiency is determined via the statistical analysis of the means and standard deviation of the dataset. This can be investigated using the following method; however, it is noted that other, more complex statistical approaches may also be utilised.

SAS PROC SURVEYSELECT was run iteratively on all data points to randomly select (using simple random sampling without replacement) and remove one observation at a time. Gas content values, standard deviations and a two-sided t-statistic (at 95% confidence) were calculated at each iteration. Uncertainty was then calculated using the formula:

- Uncertainty = (standard deviation * t-statistic) / SQRT(sample size)

This was then converted to a percentage by:

- Uncertainty Percentage = Uncertainty / Mean

Sample frequency for Domain 1 is considered sufficient, with an uncertainty of 22% achieved with only 80 samples (Figure 10). This is clearly enough samples given the small standard deviation in results.

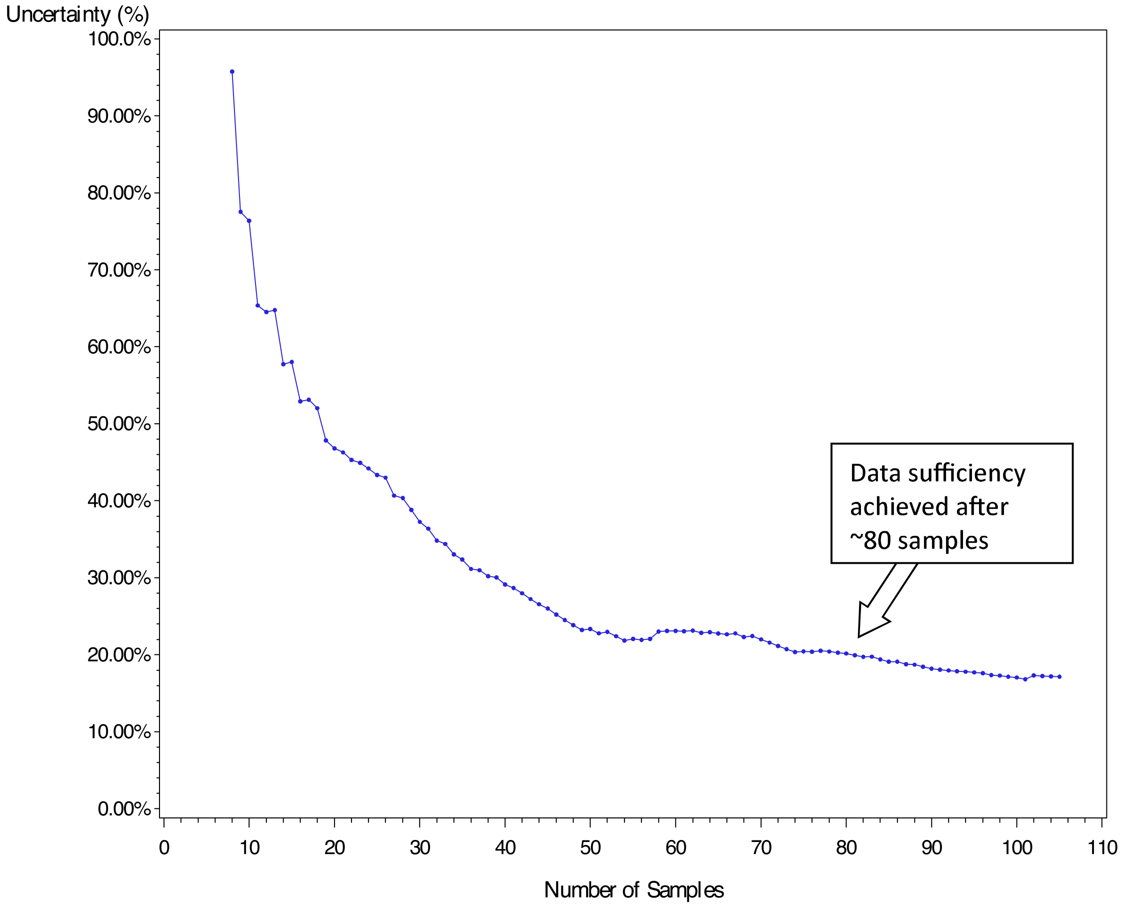


Figure 10: Data sufficiency analysis curve (at 95% confidence) for Domain 1.

6. METHOD FOR CALCULATING GAS CONTENT

6.1 THE METHOD

CoalBed has utilised the SAS LOESS procedure for this assessment to estimate the gas content of all potential gas-bearing strata, with depth. The SAS LOESS procedure implements a nonparametric method for estimating regression surfaces pioneered by Cleveland, Devlin, and Grosse (1988), Cleveland and Grosse (1991), and Cleveland, Grosse, and Shyu (1992)[23]. The SAS LOESS procedure offers great flexibility because it requires no assumptions about the parametric form of the regression surface.

The SAS LOESS procedure is appropriate for situations where you do not know a suitable parametric form of the regression surface. Furthermore, the SAS LOESS procedure is suitable when outliers are present, and a robust fitting method is required.

In the SAS LOESS method, weighted least squares are used to fit linear or quadratic functions of the predictors at the centres of neighbourhoods. The radius of each neighbourhood is chosen so that the neighbourhood contains a specified percentage of the data points. The fraction of the data, called the smoothing parameter, in each local neighbourhood controls the smoothness of the estimated surface. Data points in each local neighbourhood are weighted by a smooth, decreasing function of their distance from the neighbourhood's centre.

The result is an equation that can calculate gas content (Figures 11) and composition (Figure 12) for discrete depth intervals in the IPC geological model. For gas composition, CoalBed uses CH_4:CO_2 ratios (N_2-free, expressed as a percentage).

[23] *Cleveland, W. S., Devlin, S. J., and Grosse, E. (1988), "Regression by Local Fitting," Journal of Econometrics, 37, 87–114. Cleveland, W. S. and Grosse, E. (1991), "Computational Methods for Local Regression," Statistics and Computing, 1, 47–62. Cleveland, W. S., Grosse, E., and Shyu, M.-J. (1992), "A Package of C and Fortran Routines for Fitting Local Regression Models," Unpublished.*

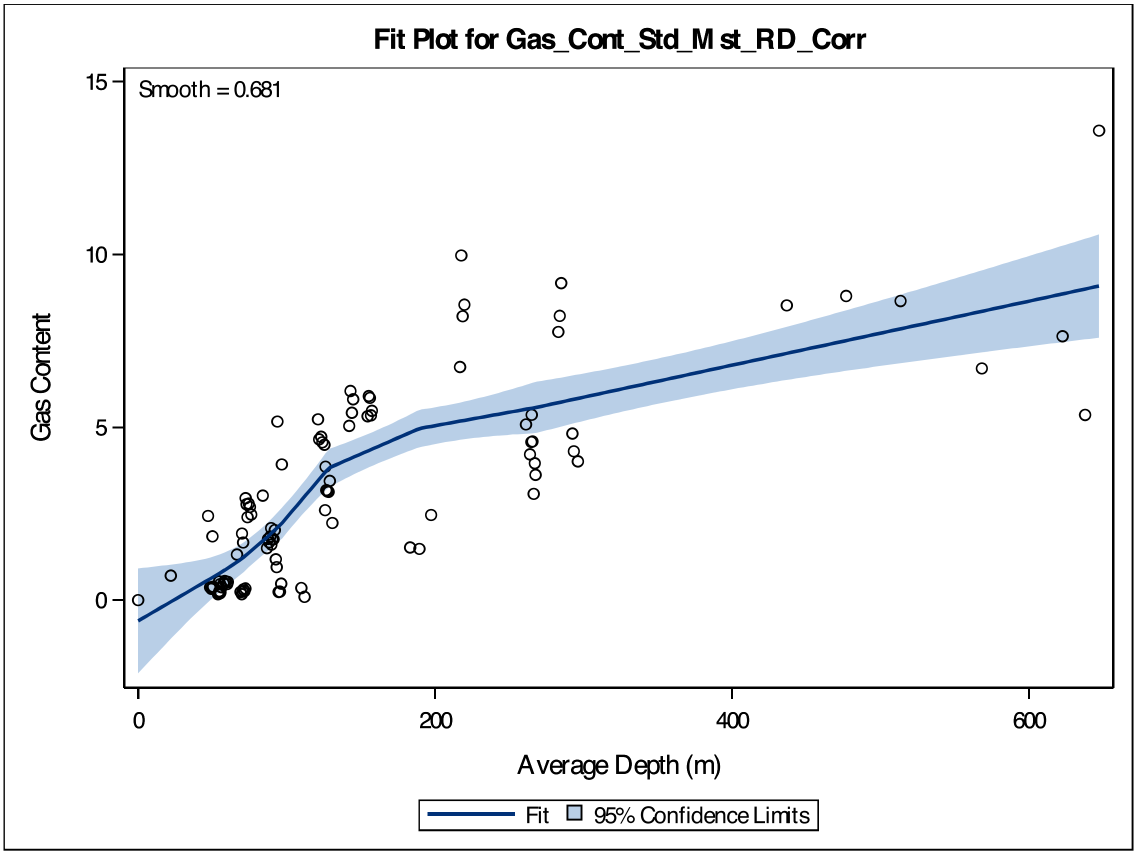


Figure 11: Fit plot for gas content LOESS regression model showing 95% prediction confidence limits for Domain 1.

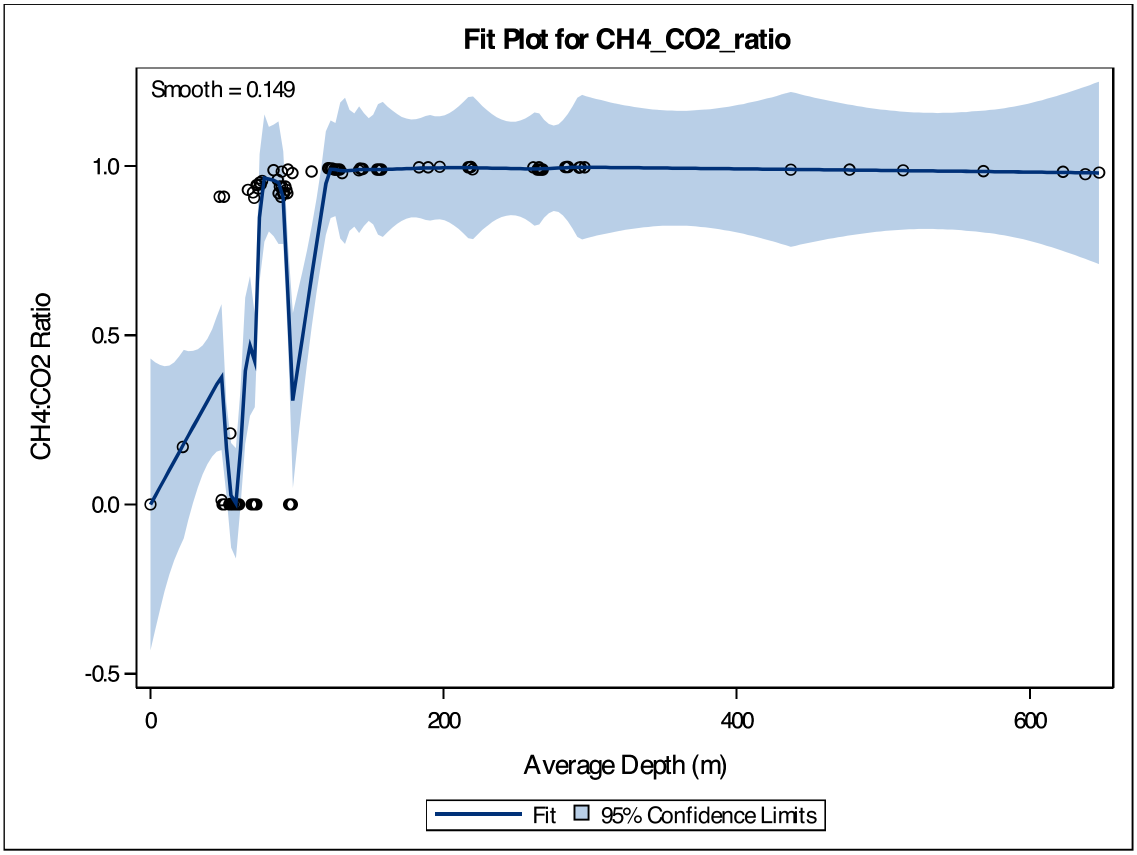


Figure 12: Fit plot of gas composition for LOESS regression model showing 95% prediction confidence limits for Domain 1.

6.2 CALCULATING BIAS

Bias is another type of error that can arise due to the improper use of equations and formulas to produce a particular outcome. The issue of bias has been assessed by calculating gas content residuals (i.e., the differences between each sample's measured and calculated results).

Residual analysis, both the residuals by depth and those predicted by the LOESS model, shows slight heteroscedasticity (non-constant variance). However, this may be attributed to data scarcity at greater average depths rather than to model misspecification. No obvious pattern in the residuals is evident.

This process was completed for gas content (Figures 13 and 14) and gas composition (Figures 15 and 16) predictions.

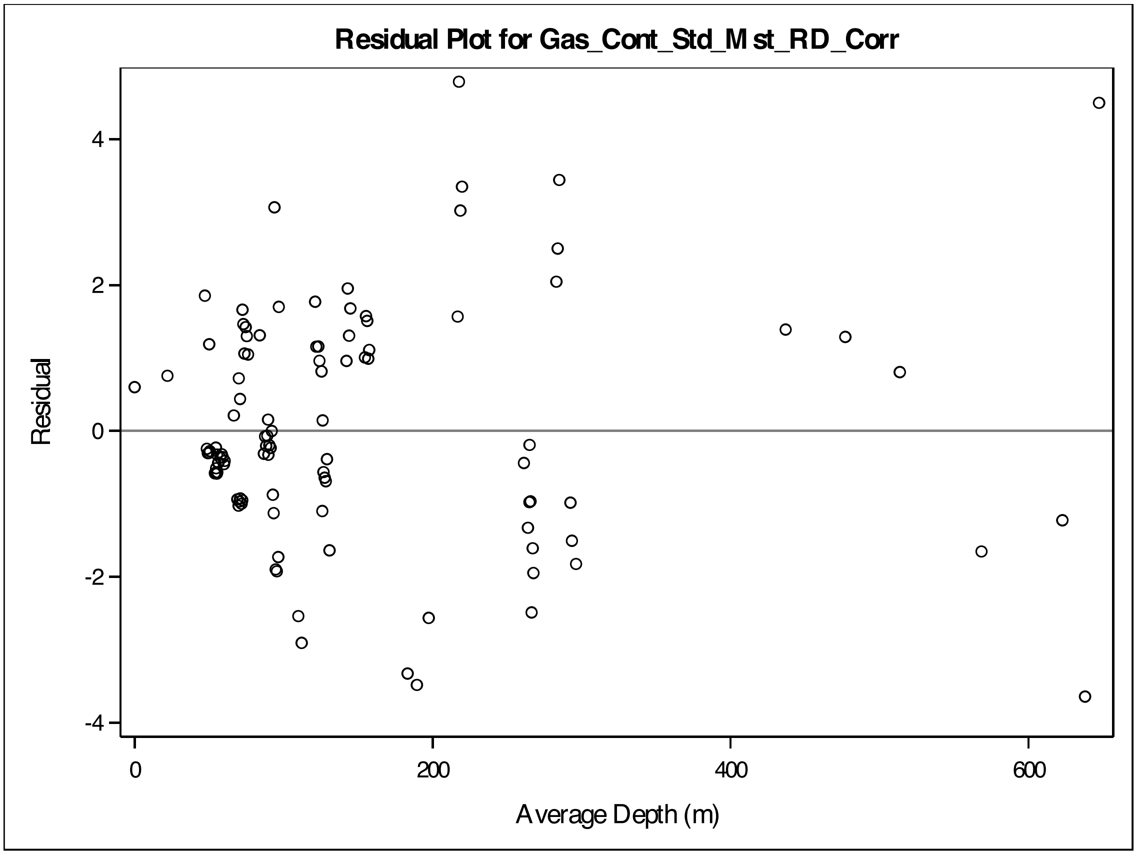


Figure 13: *IPC Domain 1 gas content residuals by depth.*

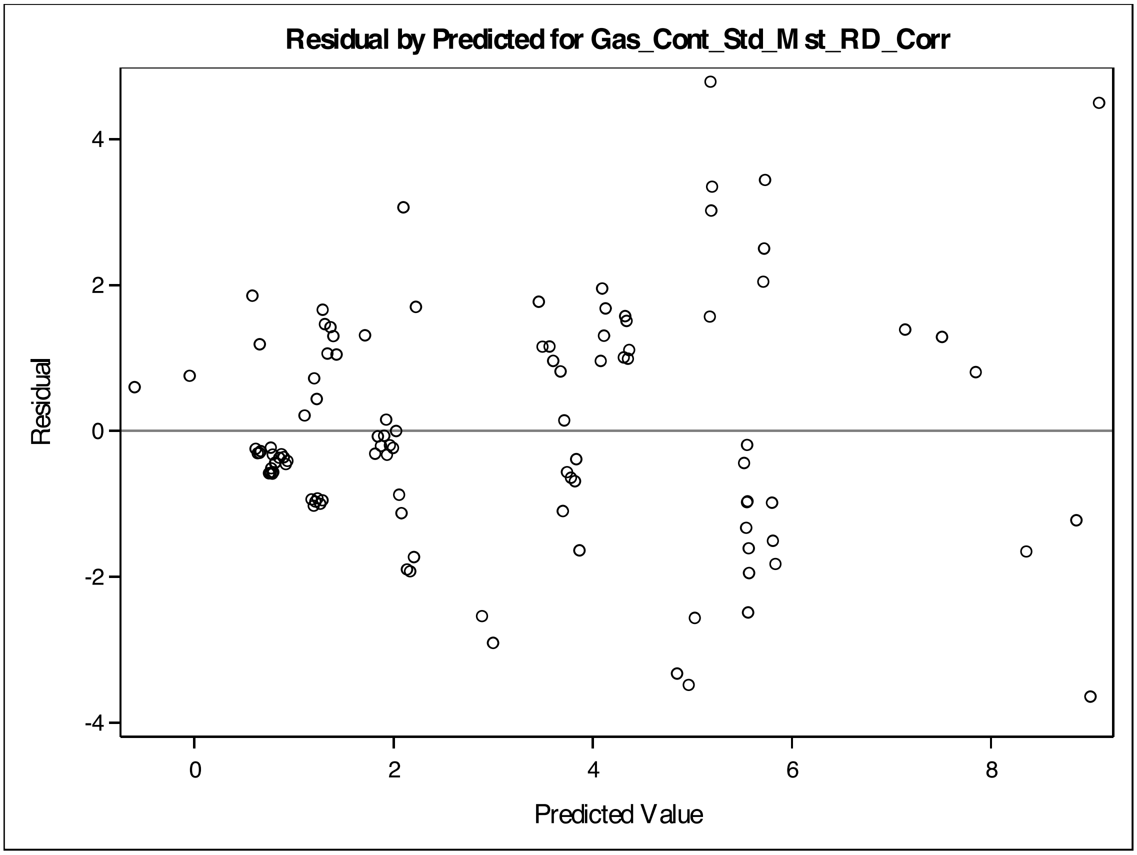


Figure 14: IPC Domain 1 gas content residuals by predicted values.

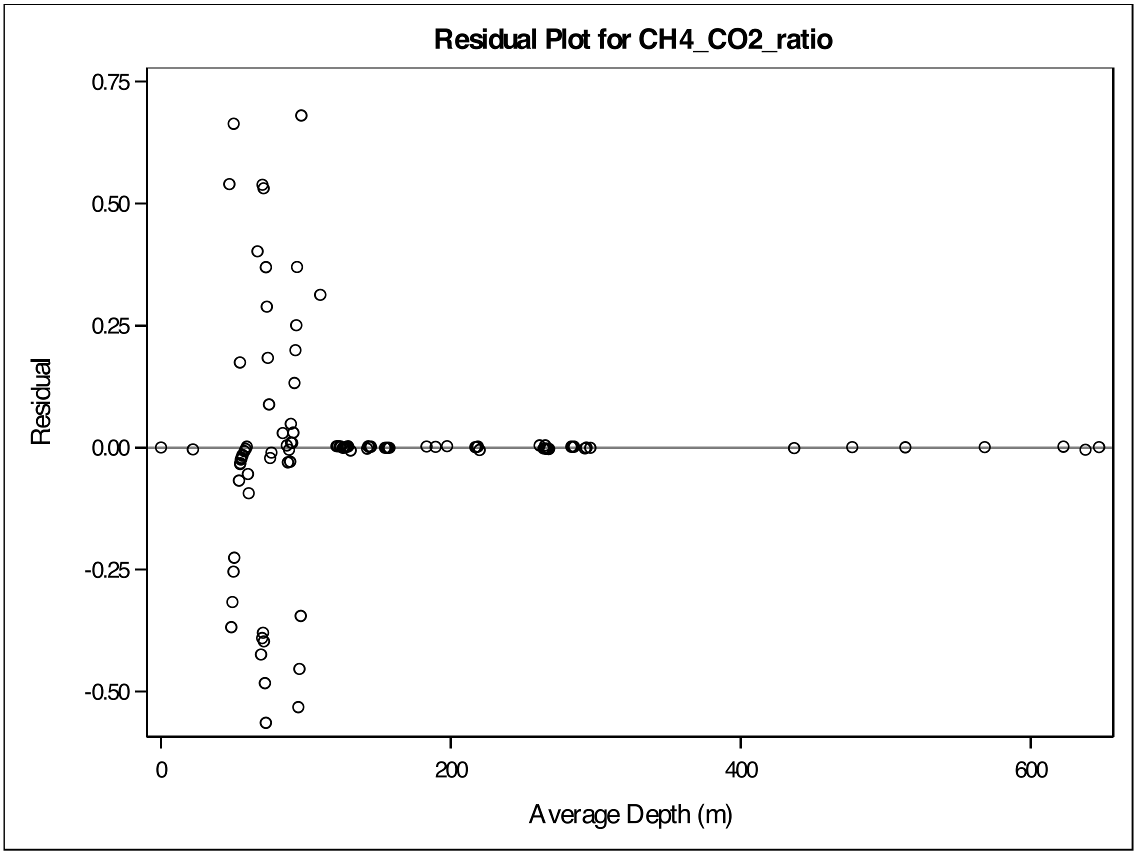


Figure 15: *IPC Domain 1 gas composition residuals by depth.*

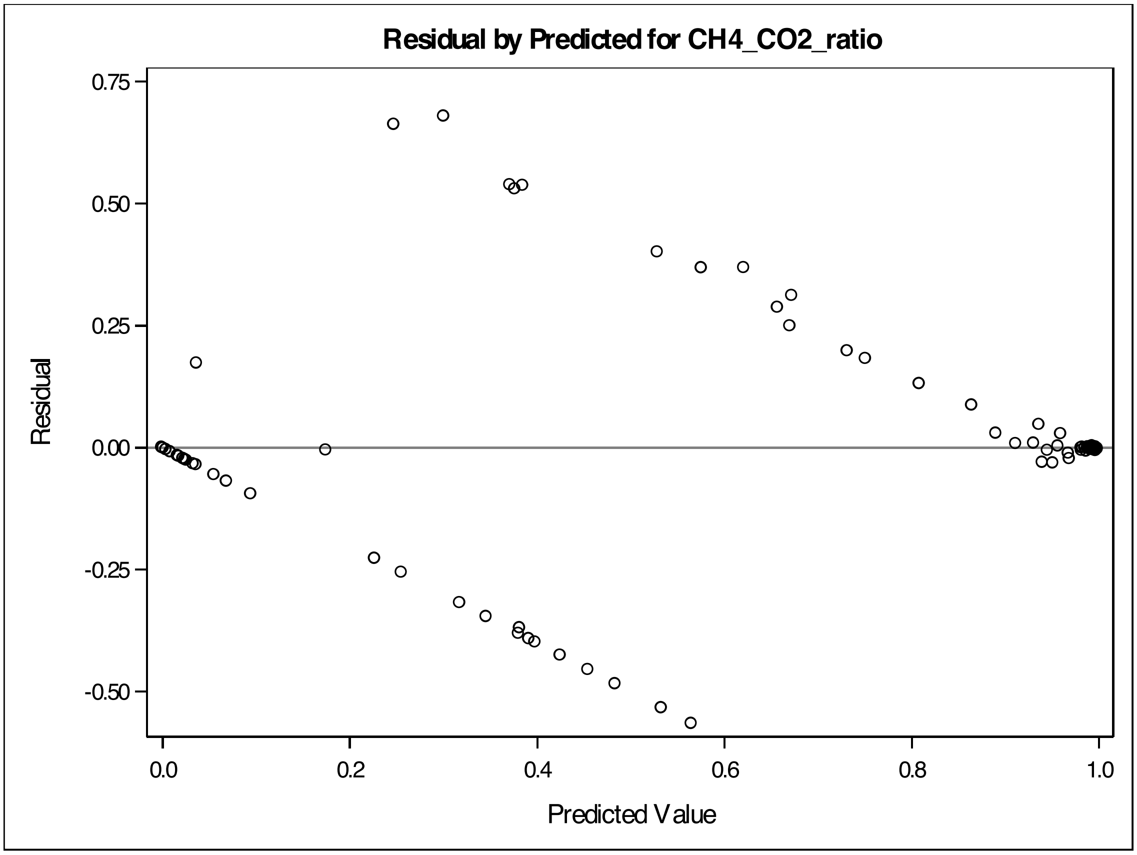


Figure 16: *IPC Domain 1 gas composition residuals by predicted values.*

7. GAS CONTENT ESTIMATE

Gas content and composition values for IPC have been produced using the SAS LOESS procedure to establish relationships with depth (Table 2). The result is a calculated gas content and composition for discrete depth intervals, which can then be used to determine a representative CO_2-e value. IPC can then multiply this CO_2-e value by the total in-situ tonnes of a particular depth interval to calculate fugitive emissions. This data can also be uploaded into the IPC geological model to aid in future fugitive emissions estimates.

Table 2: Summary of CO_2-e estimates for IPC Domain 1[24,25].

Depth Interval	No. of Samples	Gas Content (m^3/t)	CH_4 (Ratio)	CO_2 (Ratio)	CO_2-e (kg/t) as a Function of CH_4	CO_2-e (kg/t) as a Function of CO_2	TOTAL CO_2-e (kg/t)	TOTAL CO_2-e (t/t)
0 to 25m	1	0.00	0.09	0.91	0.00	0.00	0.00	0.00000
25 to 50m	3	0.61	0.36	0.64	4.12	0.73	4.86	0.00486
50 to 75m	30	0.99	0.26	0.74	4.96	1.36	6.32	0.00632
75 to 100m	19	1.94	0.78	0.22	28.65	0.80	29.44	0.02944
100 to 125m	6	3.34	0.89	0.11	56.69	0.65	57.34	0.05734
125 to 150m	12	3.88	0.99	0.01	72.91	0.08	72.99	0.07299
150 to 175m	5	4.34	0.99	0.01	81.64	0.08	81.72	0.08172
175 to 200m	3	4.95	0.99	0.01	93.48	0.05	93.52	0.09352
200 to 225m	4	5.19	1.00	0.00	98.12	0.04	98.16	0.09816
225 to 250m	0	5.34	0.99	0.01	100.77	0.06	100.83	0.10083
250 to 275m	8	5.55	0.99	0.01	104.64	0.08	104.72	0.10472
275 to 300m	6	5.77	1.00	0.00	109.20	0.04	109.24	0.10924
300 to 325m	0	5.99	1.00	0.00	113.30	0.04	113.34	0.11334
325 to 350m	0	6.22	1.00	0.00	117.55	0.06	117.61	0.11761
350 to 375m	0	6.45	0.99	0.01	121.79	0.07	121.86	0.12186
375 to 400m	0	6.68	0.99	0.01	126.02	0.09	126.10	0.12610
400 to 425m	0	6.91	0.99	0.01	130.23	0.11	130.34	0.13034
425 to 450m	1	7.14	0.99	0.01	134.34	0.12	134.47	0.13447
450 to 475m	0	7.38	0.99	0.01	138.63	0.14	138.77	0.13877
475 to 500m	1	7.51	0.99	0.01	141.05	0.16	141.20	0.14120
500 to 525m	1	7.85	0.99	0.01	147.16	0.19	147.35	0.14735
525 to 550m	0	8.07	0.99	0.01	151.13	0.21	151.35	0.15135
550 to 575m	1	8.36	0.98	0.02	156.25	0.24	156.49	0.15649
575 to 600m	0	8.53	0.98	0.02	159.40	0.26	159.66	0.15966
600 to 625m	1	8.86	0.98	0.02	165.17	0.31	165.47	0.16547
625 to 650m	2	9.04	0.98	0.02	168.42	0.33	168.75	0.16875

[24] *Columns 3-8 have been rounded to two decimal places for presentation purposes.*
[25] *m^3/t = cubic metres per tonne, kg/t = kilograms per tonne and t/t = tonne per tonne.*

It is important to note that gas emissions originating from within 20m of the **final pit floor horizon** are assigned a release factor of 50%. Therefore, all CO_2-e calculations for the floor must be halved to correctly report fugitive emission liabilities.

8. CONCLUSIONS AND RECOMMENDATIONS

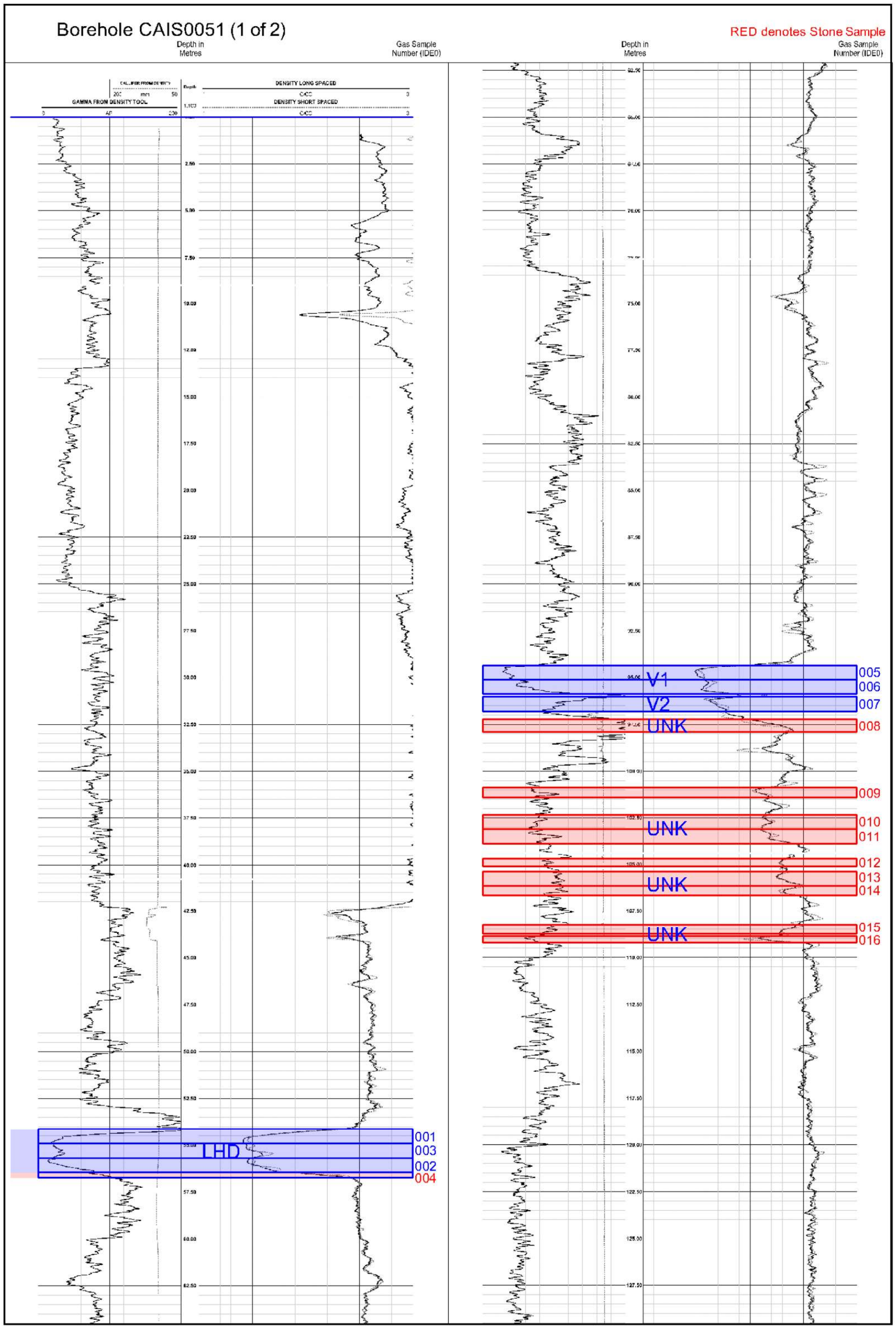
The following key points have emerged from the reservoir characterisation, analysis and compliance assessment:

1. A fugitive emission assessment satisfying Method 2 criteria has been completed at IPC for Domain 1.
2. A single distinct gas domain appears to be present at IPC (Domain 1).
3. Domain 1 shows low gas to 100m depth, followed by a rapid ramp-up in gas content from 100-200m, then a decrease in gradient of increase from 200m+. Methane dominates as the primary gas from 75m+. This domain was identified in all valid boreholes.
4. There is sufficient spatial coverage of the mining lease areas, and data sufficiency/uncertainty is adequate.

APPENDIX I – LABORATORIES REPORTS 2025

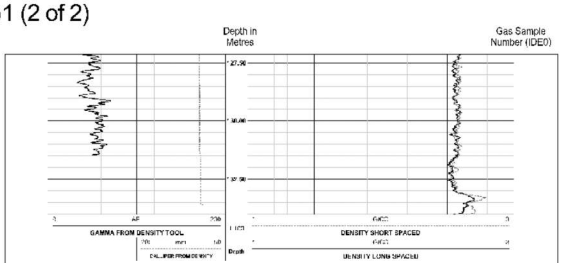
GeoGAS Pty Ltd
GAS CONTENT TESTING
ISAAC DOWNS EXTENSION
BOREHOLES CAIS0051, CAIS0065 & CAIS0067
Stanmore Resources Ltd
Report No.:2025-2151 / October 2025

APPENDIX II – NEW 2025 'TYPE' BOREHOLE ASSESSMENT



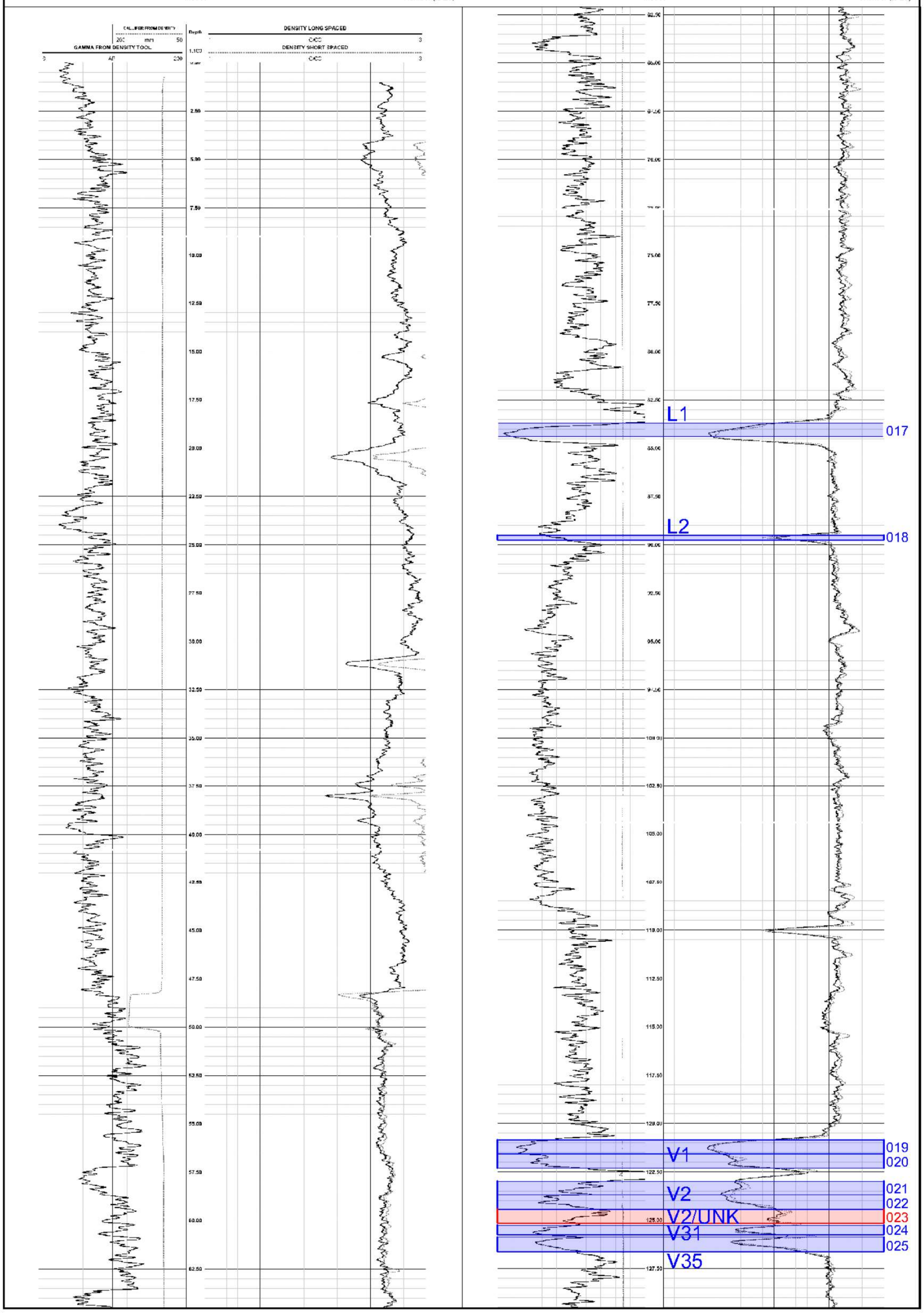
Borehole CAIS0051 (2 of 2)

RED denotes Stone Sample



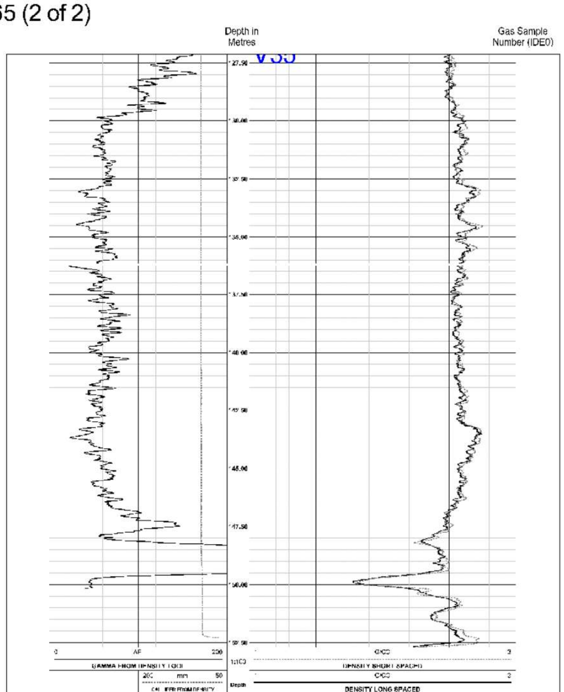
Borehole CAIS0065 (1 of 2)

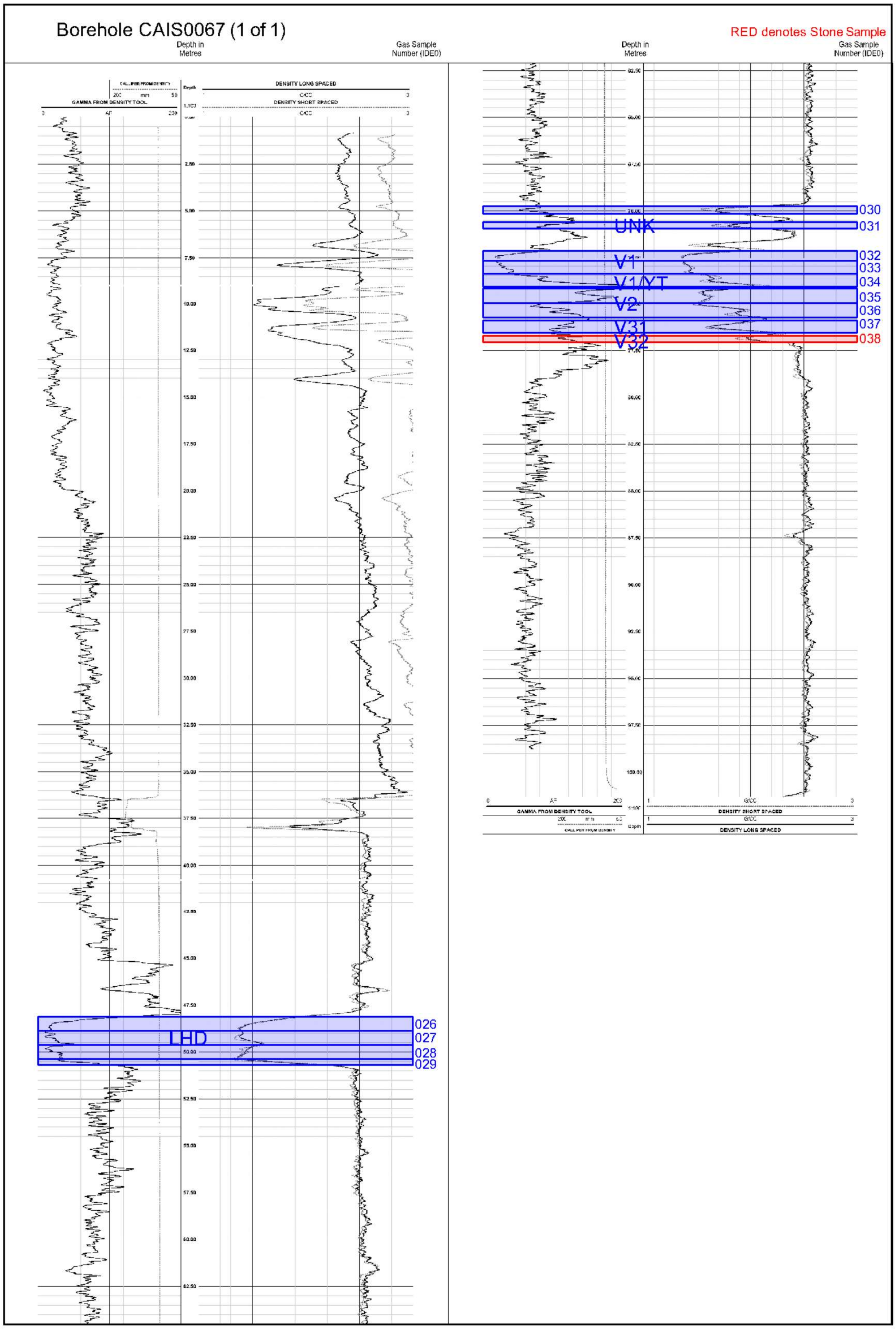
RED denotes Stone Sample



Borehole CAIS0065 (2 of 2)

RED denotes Stone Sample




Borehole CAIS0067 (1 of 1)
RED denotes Stone Sample
Depth in Metres
Gas Sample Number (IDE0)
GAMMA FROM DENSITY TOOL
CALIPER FROM DENSITY
DENSITY LONG SPACED
DENSITY SHORT SPACED
LHD
026
027
028
029
UNK
V1
V1/YT
V2
V31
V32
030
031
032
033
034
035
036
037
038

APPENDIX III – FINAL DATABASE

Borehole Number	Average Depth (m)	Gas Content 15 degrees C / Standard Density / Insitu Moisture	CH4/(CH4+CO2)
IPC692	69.02	0.24	0.00
IPC692	69.81	0.17	0.00
IPC692	70.39	0.25	0.00
IPC692	70.96	0.31	0.00
IPC692	71.71	0.27	0.00
IPC692	72.32	0.34	0.00
IPC781	53.83	0.17	0.00
IPC781	54.50	0.19	0.21
IPC781	55.17	0.20	0.00
IPC783	57.61	0.48	0.00
IPC783	58.39	0.56	0.00
IPC783	59.18	0.54	0.00
IPC783	59.96	0.46	0.00
IPC783	60.51	0.52	0.00
CAIN0002	125.97	2.60	0.99
CAIN0002	126.80	3.18	0.99
CAIN0002	127.58	3.14	0.99
CAIN0002	128.35	3.13	0.99
CAIN0002	129.11	3.45	0.99
CAIN0002	130.82	2.23	0.98
CAIN0006	154.59	5.32	0.99
CAIN0006	155.37	5.90	0.99
CAIN0006	156.11	5.85	0.99
CAIN0006	156.83	5.34	0.99
CAIN0006	157.50	5.48	0.99
CAIE0035	263.99	4.22	0.99
CAIE0035	264.91	4.57	0.99
CAIE0035	265.69	4.59	0.99
CAIE0035	266.47	3.07	0.99
CAIE0035	267.17	3.96	0.99
CAIE0035	267.69	3.62	0.99
CAIE309	216.82	6.74	1.00
CAIE309	217.69	9.97	1.00
CAIE309	218.64	8.21	1.00
CAIE309	219.77	8.55	0.99
CAIE308	283.06	7.76	1.00
CAIE308	283.99	8.22	1.00
CAIE308	284.99	9.17	1.00
CAIN0097	142.23	5.04	0.99
CAIN0097	143.04	6.05	0.99
CAIN0097	143.98	5.42	0.99
CAIN0097	144.84	5.81	0.99
Sapphire-4	109.92	0.35	0.98

Borehole Number	Average Depth (m)	Gas Content 15 degrees C / Standard Density / Insitu Moisture	CH4/(CH4+CO2)
Sapphire-4	112.12	0.09	
Sapphire-4	183.23	1.52	1.00
Sapphire-4	189.47	1.48	1.00
Sapphire-4	197.37	2.46	1.00
Sapphire-4	261.26	5.08	1.00
Sapphire-4	265.11	5.36	1.00
Sapphire-4	292.53	4.82	1.00
Sapphire-4	293.52	4.31	1.00
Sapphire-4	296.26	4.01	1.00
Sapphire-4	436.92	8.53	0.99
Sapphire-4	476.95	8.80	0.99
Sapphire-4	513.58	8.65	0.99
Sapphire-4	568.35	6.70	0.99
Sapphire-4	622.68	7.64	0.98
Sapphire-4	637.89	5.36	0.98
Sapphire-4	647.25	13.58	0.98
CAID0014	86.78	1.50	0.96
CAID0014	87.53	1.77	0.92
CAID0014	88.31	1.67	0.94
CAID0014	89.09	1.84	0.91
CAID0014	89.80	1.61	0.94
CAID0014	90.50	1.77	0.92
CAID0014	91.27	1.76	0.92
CAID0014	92.05	2.03	0.94
CAID0014	92.78	1.18	0.93
CAID0014	93.36	0.95	0.92
E548193	22.04	0.71	0.17
E548193	47.16	2.44	0.91
E548193	50.10	1.85	0.91
E755578C	66.58	1.32	0.93
E755578C	93.84	5.17	0.99
E755578C	96.82	3.93	0.98
CAIN150	54.73	0.26	0.00
CAIN150	55.49	0.23	0.00
CAIN150	56.26	0.38	0.00
CAIS0051	54.54	0.54	0.00
CAIS0051	55.32	0.46	0.00
CAIS0051	56.08	0.37	0.00
CAIS0051	94.71	0.24	0.00
CAIS0051	95.48	0.24	0.00
CAIS0051	96.42	0.48	0.00
CAIS0065	84.00	3.02	0.99
CAIS0065	89.60	2.08	0.98
CAIS0065	121.19	5.23	0.99
CAIS0065	121.92	4.65	0.99
CAIS0065	123.32	4.72	0.99
CAIS0065	124.05	4.57	0.99

Borehole Number	Average Depth (m)	Gas Content 15 degrees C / Standard Density / Insitu Moisture	CH4/(CH4+CO2)
CAIS0065	125.51	4.49	0.99
CAIS0065	126.25	3.86	0.99
CAIS0067	48.50	0.37	0.01
CAIS0067	49.26	0.33	0.00
CAIS0067	50.01	0.35	0.00
CAIS0067	50.53	0.39	0.00
CAIS0067	69.97	1.92	0.92
CAIS0067	70.77	1.67	0.91
CAIS0067	72.40	2.95	0.94
CAIS0067	73.01	2.78	0.94
CAIS0067	73.71	2.40	0.93
CAIS0067	74.55	2.79	0.95
CAIS0067	75.32	2.70	0.95
CAIS0067	76.21	2.48	0.96

APPENDIX C *FEASIBILITY OF PRE-DRAINAGE CAPTURE*: ISAAC PLAINS COMPLEX. COALBED ENERGY

FILE NOTE

FEASIBILITY OF PRE-DRAINAGE CAPTURE

For Stanmore Resources Ltd – Isaac Downs Extension

PREPARED BY

Scott Thomson, B. Sc., M. Sc., M.B.A. (Tech. Man.)
Managing Director,
CoalBed Energy Consultants Pty Limited

Duncan Thomson, B. Sc., M. Eng.
Technical Director,
CoalBed Energy Consultants Pty Limited

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FILE NOTE

Stanmore Resources Ltd (Stanmore), through wholly owned subsidiary entities, operates the open-cut coal mine Isaac Plains Complex (IPC) in the Bowen Basin, QLD. IPC comprises Isaac Plains Mine (IPM), Isaac Downs Mine (IDM) and the proposed Isaac Downs Extension (IDE) Project (the Project). IPC has undertaken coal seam gas studies at its open-cut operations to assess long-term fugitive emissions[1]. The intent of this File Note is to provide a high-level review of the pre-drainage capture potential for the future IDE mining areas. The information in this file note is intended to support the Environmental Impact Statement (EIS) for the Project.

The following fundamental characteristics of the reservoir are relevant to pre-drainage capture:

- Gas content (m^3/t).
- Gas composition (%).
- Gas saturation (%).
- Permeability (mD).
- Net coal (m).

For successful and commercially viable gas extraction from coal, all these factors must be favourable. From a Coal Seam Gas (CSG) producer's perspective, if any of these factors are unfavourable, the outcome will likely be a non-commercial project with unreasonable drilling and handling costs.

This review of geological and gas properties at IDE[2] reveals the following:

- Coal gas is contained in a multiple-seam environment.
- Coals generally have low gas content (< 2 m^3/t to a depth of ~100m, the planned mining limit).
- Coals are variably undersaturated.
- CO_2 is commonly found in parts of the proposed mining areas, and there are currently no commercially available methods to abate CO_2.
- Permeability is anticipated to be reasonable at these relatively shallow depths. However, recent fieldwork suggests that the shallow sub-surface is a "leaky" gas reservoir, which is problematic for established gas capture methods.

Given these gas reservoir properties, it will be challenging to produce meaningful gas (CH_4 or CO_2) at IDE through pre-drainage of the planned opencut mining area. Low gas content, a high CO_2 proportion, a "leaky" gas reservoir, and variable gas

[1] *CoalBed Energy Consultants – Fugitive Emissions Compliance Assessment, For Stanmore Resources Ltd, Isaac Plains Complex, 25th November 2025.*
[2] *CoalBed Energy Consultants – Fugitive Emissions Compliance Assessment, For Stanmore Resources Ltd, Isaac Plains Complex, 25th November 2025.*

undersaturation will limit successful pre-drainage. An added complication is the advancing highwall operation, which could increase drilling costs and risk.

Another technical issue for any attempted pre-drainage strategy at IDE is the overall gas recovery. Not all the gas will ever be obtainable. A percentage of the gas remains bonded to the coal (as residual gas). A production finishing point occurs in every pre-drainage well, at an 'abandonment pressure'. Potentially low gas recovery will also provide significant operational challenges for gas capture and render the overall feasibility of on-site mitigation unfeasible.

A final consideration is that current underground industry mitigation practices are associated with surface flaring of CH_4. CO_2, once extracted, cannot be abated by flaring and must be vented, thereby negating any emission-reduction potential by pre-draining. CO_2 storage options are extremely cost-prohibitive and will not provide a feasible emission management strategy for the Project.

In summary:

- IDE shows no realistic potential for pre-drainage due to its low gas content and other technical challenges (low gas saturation, 'leaky' reservoir character, gas composition) at target mining depths (<100m).
- No significant gas mitigation capacity exists until depths exceeding 200m (minimum). This is due to all the technical issues listed above (gas content, composition, saturation levels and a "leaky" gas reservoir).

Technical limitations similar to those discussed above have prevented successful long-term pre-drainage to date in existing open-cut operations in NSW and QLD.

At an operating depth of <100m, the Project faces significantly more challenges than other deeper NSW and QLD opencut mining projects, which offer greater potential for pre-drainage methodology. In addition, no project worldwide (CSG or otherwise) has ever successfully captured meaningful volumes of gas at this shallow depth.