APPENDIX O

Appendix O - Greenhouse Gas Assessment

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Tahmoor South Project

Greenhouse Gas Assessment

23 November 2018

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The business of sustainability

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November 2018

Tahmoor South Project

Greenhouse Gas Assessment

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1. INTRODUCTION

ERM has been commissioned by Tahmoor Coal Pty Ltd (Tahmoor), a wholly owned subsidiary of SIMEC (Australia) Mining Pty Ltd, to complete a Greenhouse Gas (GHG) assessment for the Tahmoor South Project (the Project). The GHG assessment will form a component of the Environmental Impact Statement (EIS) for the Project under Part 4 the Environmental Planning and Assessment Act 1979 (EP&A Act).

1.1 Background

Tahmoor Coal owns and operates the Tahmoor Mine; an underground coal mine located approximately 80 km south-west of Sydney, in the Southern Coalfields of NSW. Tahmoor currently extracts approximately 3 million tonnes per annum (Mtpa) of Run-of-Mine (ROM) coal from its existing operations at the Tahmoor Mine, and undertakes underground mining under existing development consents, licences and the conditions of relevant mining leases.

The proposed development seeks to extend the life of underground mining at Tahmoor Mine until approximately 2035 and increase production to 4 Mtpa. The proposal will enable mining to be undertaken within the southern portion of Tahmoor Coal's existing lease areas and for operations and employment of the current workforce to continue for a further 13 years.

The proposed development will extend mining at Tahmoor Mine within the Project Area, using longwall methods, with the continued use of ancillary infrastructure at the existing Tahmoor Mine surface facilities area. The Project Area is adjacent and to the south of the existing Tahmoor Approved Mining Area. It also overlaps a small area of the existing Tahmoor Approved Mining Area comprising the surface facilities area, historical workings and other existing mine infrastructure.

It is noted that the currently operating longwall mining at Tahmoor North, is anticipated to be completed in 2022.

1.1.1 Mine ventilation

The Tahmoor South Project will utilise the existing mine's ventilation system. In addition the Project will require the construction of two new ventilation shafts to provide reliable and adequate supply of ventilation air to personnel in the mine to ensure a safe working environment is maintained.

1.1.2 Gas drainage operations

Pre-gas drainage activities are undertaken underground, via drilling and drainage from the roadways developed for longwall panels. Gas will be drawn from the coal seam by vacuum and piped to the onsite gas plant at the surface facilities area via the underground pipe network. Underground gas drainage of the coal seam will continue ahead of longwall development for the life of mining.

Energy Developments Limited (EDL) operates a Waste Coal Mine Gas (WCMG) Power Plant at Tahmoor Mine, on land leased from Tahmoor Coal.

Gas management at Tahmoor Mine consists of the following infrastructure:

- Tahmoor Mine Gas Plant;
- Tahmoor Mine Gas Plant Vent;
- Tahmoor Mine Flare Plant; and
- WCMG Power Plant, if available.

Commercial agreements are in place between Tahmoor Coal and EDL for the WCMG Power Plant to operate until 2020. If the WCMG Power Plant is not operated, the gas will be diverted to the Tahmoor Mine Flare Plant, which has sufficient design capacity to accommodate this additional gas.

At the gas plant, the collected gas is tested to determine its composition and processed via one of the three possible options available at Tahmoor Mine:

- If the gas has sufficient methane, it will be used to generate electricity at the existing WCMG Power Plant, while the WCMG Power Plant is operational at Tahmoor Mine.
- If the gas composition does not meet the specification for electricity generation or in the circumstances where the WCMG Power Plant is not operational at Tahmoor Mine, it will be sent to the onsite gas flare plant where the methane will be flared.
- If the gas does not have sufficient methane for the operation of the flare plant, it will be vented to the atmosphere at gas vent stack at the gas plant.

The existing gas plant, WCMG Power Plant and gas flare plant will continue to be utilised and will be upgraded as required.

1.1.3 Post gas drainage

Post gas drainage will be required as strata relaxation caused by the retreating underground longwall face will liberate volumes of gas into the mine workings from the underlying Wongawilli seam and from overlying strata, which is released due to fracturing of the goaf. At the conclusion of mining from each panel, the panel will be sealed and gas drawn from the sealed areas as part of the post gas drainage operations. Additionally, boreholes are proposed to be drilled from the mine workings into the Wongawilli seam. These boreholes will be designed to collect the gas at its source or to intercept gas before it migrates into the mine workings.

The gas collected from the in-seam and cross-measure boreholes will be drawn by vacuum via the underground pipe network to the on-site gas plant located at the surface facilities area.

1.1.4 Mine ventilation return air

The ventilation system will deliver fresh air into the mine from the existing and proposed downcast vent shafts and will extract stale air from the mine via the proposed upcast vent shaft.

Some methane is contained within the mine ventilation return air, and this is vented to the atmosphere at the upcast shaft.

2. RELEVANT LEGISLATION

2.1 International framework

2.1.1 Intergovernmental Panel on Climate Change

The Intergovernmental Panel on Climate Change (IPCC) is a panel established in 1988 by the World Meteorological Organisation (WMO) and the United Nations Environment Programme (UNEP) to provide independent scientific advice on climate change. The panel was originally asked to prepare a report, based on available scientific information, on all aspects relevant to climate change and its impacts and to formulate realistic response strategies. This first assessment report of the IPCC served as the basis for negotiating the United Nations Framework Convention on Climate Change (UNFCCC).

The IPCC also produce a variety of guidance documents and recommended methodologies for GHG emissions inventories, including (for example):

- 2006 IPCC Guidelines for National GHG Inventories; and
- Good Practice Guidance and Uncertainty Management in National GHG Inventories (2000).

Since the UNFCCC entered into force in 1994, the IPCC remains the pivotal source for scientific and technical information relevant to GHG emissions and climate change science.

The IPCC operates under the following mandate: “to provide the decision-makers and others interested in climate change with an objective source of information about climate change”. The IPCC does not conduct any research nor does it monitor climate-related data or parameters. Its role is to assess on a comprehensive, objective, open and transparent basis the latest scientific, technical and socio-economic literature produced worldwide, relevant to the understanding of the risk of human-induced climate change, its observed and projected impacts and options for adaptation and mitigation. IPCC reports should be neutral with respect to policy, although they need to deal objectively with policy relevant scientific, technical and socio economic factors. They should be of high scientific and technical standards, and aim to reflect a range of views, expertise and wide geographical coverage” (IPCC, 2011).

The stated aims of the IPCC are to assess scientific information relevant to:

- Human-induced climate change;
- The impacts of human-induced climate change; and
- Options for adaptation and mitigation.

IPCC reports are widely cited within international literature, and are generally regarded as authoritative.

2.1.2 United Nations Framework Convention on Climate Change

The UNFCCC sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. It recognises that the climate system is a shared resource, the stability of which can be affected by industrial and other emissions of CO_2 and other GHGs. The convention has near-universal membership, with 172 countries (parties) having ratified the treaty, the Kyoto Protocol.

Under the UNFCCC, governments:

- Gather and share information on GHG emissions, national policies and best practices.
- Launch national strategies for addressing GHG emissions and adapting to expected impacts, including the provision of financial and technological support to developing countries.
- Cooperate in preparing for adaptation to the impacts of climate change.

2.1.3 Kyoto Protocol

The Kyoto Protocol entered into force on 16 February 2005. The Kyoto Protocol built upon the UNFCCC by committing to individual, legally binding targets to limit or reduce GHG emissions. Annex I Parties (which includes Australia) are countries that were members of the Organisation for Economic Co-operation and Development (OECD) in 1992, plus countries with economies in transition such as Russia. The GHGs included in the Kyoto Protocol were:

- Carbon dioxide (CO_2);
- Methane (CH_4);
- Nitrous oxide (N_2O);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride (SF_6)

Each of the above gases has a different effect on the earth's warming and this is a function of radiative efficiency and lifetime in the atmosphere for each individual gas. To account for these variables, each gas is given a 'global warming potential' (GWP) that is normalised to CO_2. For example, CH_4 has a GWP of 28 over a 100 year lifetime (IPCC, 2014). This factor is multiplied by the total mass of gas to be released to provide a CO_2 equivalent mass, termed 'CO_2-equivalent'.The emission reduction targets were calculated based on a party's domestic GHG emission inventories (which included land use change and forestry clearing, transportation and stationary energy sectors). Domestic inventories required approval by the Kyoto Enforcement Branch. The Kyoto Protocol required developed countries to meet national targets for GHG emissions over a five year period between 2008 and 2012.

To achieve their targets, Annex I Parties had to implement domestic policies and measures. The Kyoto Protocol provided an indicative list of policies and measures that might help mitigate climate change and promote sustainable development.

Under the Kyoto Protocol, developed countries could use a number of flexible mechanisms to assist in meeting their targets. These market-based mechanisms include:

- Joint Implementation – where developed countries invest in GHG emission reduction projects in other developed countries.
- Clean Development Mechanism – where developed countries invest in GHG emission reduction projects in developing countries.

Annex I countries that failed to meet their emissions reduction targets during the 2008-2012 period were liable for a 30 per cent penalty (additional to the level of exceedance). A second commitment period was agreed in 2012 that spans from 2013 to 2020, whereby 37 countries, including Australia, were bound to emissions targets (DFAT, 2015).

2.1.4 Paris Agreement

In 2015, a historic global climate agreement was reached under the UNFCCC at the 21st Conference of the Parties (COP21) in Paris (known as the Paris Agreement). The Paris Agreement sets in place a durable and dynamic framework for all countries to take action on climate change from 2020 (that is, after the Kyoto period), building on existing efforts in the period up to 2020. Key outcomes of the Paris Agreement include:

- A global goal to hold average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels.
- All countries to set mitigation targets from 2020 and review targets every five years to build ambition over time, informed by a global stocktake.
- Robust transparency and accountability rules to provide confidence in countries' actions and track progress towards targets.
- Promoting action to adapt and build resilience to climate change.
- Financial, technological and capacity building support to help developing countries implement the Paris Agreement.

Australia ratified the Paris Agreement in November 2016. Australia's target under the Paris Agreement is to reduce emissions by 26-28 per cent below 2005 levels by the year 2030, progressing the levels of reduction required to meet the Kyoto Protocol targets.

2.2 Australian context

According to the Department of Environment and Energy (DoEE), Australia's GHG emissions have increased by 27.9% since 1990 reaching 534.7 Million tonnes of CO_2-equivalent ($MtCO_2$-e) in 2016 (excluding Land Use, Land Use Change and Forestry - LULUCF) (DoEE, 2016a). Stationary energy excluding electricity includes emissions from direct combustion of fuels, predominantly in the manufacturing, mining, residential and commercial sectors. In 2016, stationary energy excluding electricity accounted for 18% of Australia's national inventory (DoEE, 2016).

2.2.1 National greenhouse and energy reporting framework

The National Greenhouse and Energy Reporting Act 2007 (Cth) (the NGER Act) establishes a mandatory obligation on corporations which exceed defined thresholds to report GHG emissions, energy consumption, energy production and other related information.

Corporate and facility reporting thresholds for GHG emissions and energy consumption or energy production are provided in Table 2.1.

Table 2.1 NGER reporting thresholds per financial year

Parameter	Reporting Threshold	
	Corporate	Facility
GHG Emissions (Scope 1&2) (kt CO_2-e)	50	25
Energy production (TJ)	200	100
Energy consumption (TJ)	200	100

Source: CER, 2017

If a corporation has operational control over facilities whose GHG emissions or energy use in a given reporting year:

- Individually exceed the relevant facilities threshold; or
- When combined with other facilities under the corporation's operational control, exceed the relevant corporate thresholds.

That corporation must report the relevant GHG emissions or energy use (as the case may be) for that year under the NGER Act. This may include construction or other contractors, for example.

It is anticipated that during construction, there will be multiple parties with operational control over different aspects of the site development. For this reason, while it is anticipated that there is likely to be some reporting requirement under the NGER scheme, this is likely to be apportioned across the NGER reporting corresponding to several corporations.

Once operational, the Project's total Scope 1 and 2 GHG emissions are anticipated to exceed 25,000 tonnes CO_2-e in a financial year. Because of this, the reporting of emissions is expected to be required under the NGER scheme.

Tahmoor Coal already reports under the NGER scheme. During the 2015-16 financial year Tahmoor Coal reported a total Scope 1 emissions to be 1,118 ktCO_2-e and the Scope 2 emissions to be 196 ktCO_2-e, with total emissions equating to 1,314 ktCO_2-e (Clean Energy Regulator, 2017).

3. METHODOLOGY

Quantification of GHG emissions has been performed in accordance with the GHG Protocol (WRI & WBCSD, 2004), IPCC and Australian Government GHG accounting/classification systems.

This GHGA is also guided by the emission estimation methodologies endorsed under the National Greenhouse and Energy Reporting Regulations 2008 (the NGER Regulations). These describe the detailed requirements for reporting under the NGER framework and also provide a basis for estimating emissions from proposed activities.

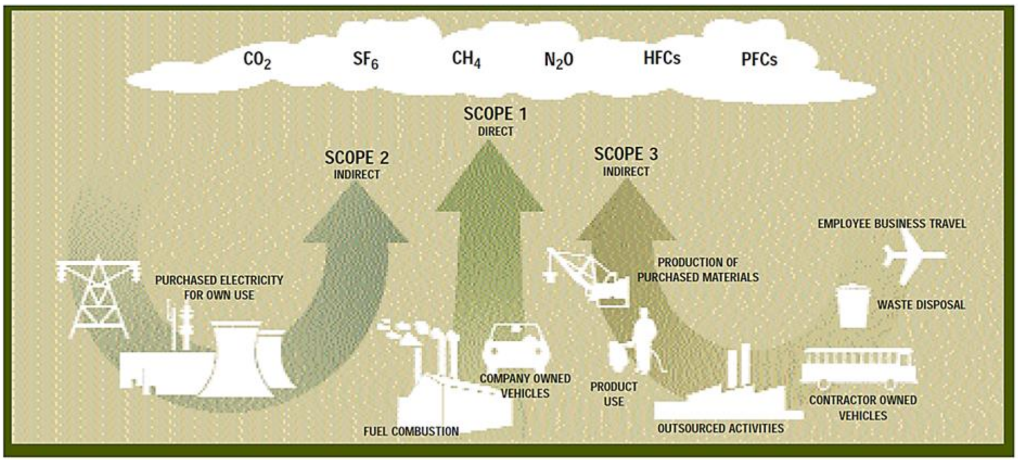
The Technical Guidelines for the Estimation of Greenhouse Gas Emissions by Facilities in Australia (the NGER Guidelines) (DoEE, 2016b) support reporting under the NGER Act. They have been designed to assist corporations in understanding and applying the NGER Measurement Determination.

The NGER Guidelines are reporting year specific, and outline calculation methods and criteria for determining GHG emissions, energy production, energy consumption and potential GHG emissions embodied in combusted fuels. The latest published NGER Guidelines (at the time of writing) have been referenced.

3.1 The GHG Protocol

The GHG Protocol establishes an international standard for accounting and reporting of GHG emissions. The GHG Protocol has been adopted by the International Organization for Standardisation, endorsed by GHG initiatives (such as the Carbon Disclosure Project) and is compatible with existing GHG trading schemes.

Under this protocol, three “scopes” of emissions (Scope 1, Scope 2 and Scope 3) are defined for GHG accounting and reporting purposes. This terminology has been adopted in Australian GHG reporting and measurement methods and has been employed in this assessment. The definitions for Scope 1, Scope 2 and Scope 3 emissions are provided in the following sections, with a visual representation provided in Figure 3.1.



Source: WRI & WBCSD 2004

Figure 3.1 Overview of scopes and emissions across a reporting entity

3.1.1.1 Scope 1: Direct greenhouse gas emissions

Direct greenhouse gas emissions are defined as those emissions that occur from sources that are owned or controlled by the reporting entity. Direct greenhouse gas emissions are those emissions that are principally the result of the following types of activities undertaken by an entity:

- Generation of electricity, heat or steam. These emissions result from combustion of fuels in stationary sources;
- Physical or chemical processing. Most of these emissions result from manufacture or processing of chemicals and materials, e.g., the manufacture of cement, aluminium, etc;
- Transportation of materials, products, waste and employees. These emissions result from the combustion of fuels in entity owned/controlled mobile combustion sources, e.g., trucks, trains, ships, aeroplanes, buses and cars; and
- Fugitive emissions. These emissions result from intentional or unintentional releases, e.g., equipment leaks from joints, seals, packing, and gaskets; methane emissions from coal mines and venting; HFC emissions during the use of refrigeration and air conditioning equipment; and methane leakages from gas transport.

3.1.1.2 Scope 2: Energy product use indirect greenhouse gas emissions

Scope 2 emissions are a category of indirect emissions that accounts for greenhouse gas emissions from the generation of purchased energy products (principally, electricity, steam/heat and reduction materials used for smelting) by the entity.

Scope 2 covers purchased electricity defined as electricity that is purchased or otherwise brought into the organisational boundary of the entity. Scope 2 emissions physically occur at the facility where electricity is generated. Entities report the emissions from the generation of purchased electricity that is consumed in its owned or controlled equipment or operations as Scope 2.

3.1.1.3 Scope 3: Other indirect greenhouse gas emissions

Scope 3 emissions are defined as those emissions that are a consequence of the activities of an entity, but which arise from sources not owned or controlled by that entity. Some examples of Scope 3 activities provided in the GHG Protocol are extraction and production of purchased materials, transportation of purchased fuels, and use of sold products and services.

The GHG Protocol provides that reporting Scope 3 emissions is optional. If an organisation believes that Scope 3 emissions are a significant component of the total emissions inventory, these can be reported along with Scope 1 and Scope 2. However, the GHG Protocol notes that reporting Scope 3 emissions can result in double counting of emissions and can also make comparisons between organisations and/or products difficult because reporting is voluntary. Double counting needs to be avoided when compiling national (country) inventories under the Kyoto Protocol. The GHG Protocol also recognises that compliance regimes are more likely to focus on the “point of release” of emissions (i.e. direct emissions) and/or indirect emissions from the purchase of electricity.

Under the NGER Act, facilities triggering greenhouse emission and energy usage thresholds are required to report Scope 1 and Scope 2, but not Scope 3.

Scope 1 emissions from the Project comprise:

- Run-of-mine coal extracted from gassy underground mine;
- Collection and venting/flaring of pre-drained gas
- Collection and venting/flaring of goaf gas (post drainage);
- Venting of mine ventilation return air;
- Diesel oil combustion;

- Petrol combustion;
- Post-mining activities; and
- Use of sulfur hexafluoride (SF_6)

Scope 2 emissions from the Project are limited to electricity consumption.

3.2 National Greenhouse and Energy Reporting (Measurement) Determination 2008

The National Greenhouse and Energy Reporting (Measurement) Determination 2008 (the NGER Determination) commenced on 1 July 2008 and is made under subsection 10 (3) of the NGER Act. It provides a framework for the measurement of the following arising from the operation of facilities:

- Greenhouse gas emissions;
- The production of energy; and
- The consumption of energy.

The determination addresses Scope 1 and Scope 2 emissions. The methods are presented in a tiered structure with higher tiers producing less uncertain results but requiring more data to employ. In the NGER Determination there are 4 categories of Scope 1 emissions (the code for the IPCC classification is provided in brackets):

- Fuel combustion (UNFCCC Category 1.A);
- Fugitive emissions from fuels, which deals with emissions released from the extraction, production, flaring of fuel, processing and distribution of fossil fuels (UNFCCC Category 1.B);
- Industrial processes emissions (UNFCCC Category 2); and
- Waste emissions (UNFCCC Category 6).

It is acknowledged that as the NGER Guidelines are derived from the NGER Determination, where there is a perceived contradiction between the NGER Guidelines and NGER Determination, the NGER Determination has taken precedence.

3.3 Assessment approach

GHG emissions have been estimated for the Project and the existing TIPS facilities based upon the methods outlined in the following documents:

- The National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2008;
- Site specific information;
- The NGER Guidelines; and
- The NGA Factors.

4. GREENHOUSE GAS CALCULATIONS

4.1 Introduction

The following sections present the GHG calculations and resultant estimated emissions from each of the GHG scopes as described in Section 3.1. All GHG calculations have been made using the relevant equations and emissions factors given within the NGER Measurement Determination. Data provided by Tahmoor Coal has been used as input into these equations.

Consumption data (diesel use, electricity consumption etc.) for the Project has been provided by Tahmoor Coal for fiscal years 2009/2010, 2010/2011, 2011/2012 and 2012 to March 2013 in the form of NGER Scheme declarations.

ROM and product coal values for these years along with the projections for the Project years (2019 to 2035) have also been provided. As projections of future years' consumption data has not been provided, intensity factors of consumption per tonne of ROM coal have been calculated to estimate future consumption levels. A total of all year's consumption was taken and divided by the total ROM coal over the same period. These intensity factors are as listed in Table 4.1 below:

Table 4.1 Intensity factors for consumables used for future project year scenarios

Year	ROM Coal Mined (kt)	Diesel (kL)	Petrol (kL)	Oils (kL)	Lubricants (kL)	Electricity (MWh)	SF_6 (CO_2-et/t)
2009/2010	1,552	684	16	0	226	70,890	174
2010/2011	1,647	781	17	0	171	53,091	174
2011/2012	2,731	1,171	15	0.8	198	95,265	411
2012/2013	1,601	688	11	0	118	58,956	174
TOTAL	7,531	3,324	58	1	713	278,202	933
Intensity Factor (Usage/kt ROM)		0.44	0.008	0.0001	0.095	36.9	0.12

4.2 Fugitive emissions – Scope 1 emissions

Estimates of Scope 1 emissions from fugitive methane have been provided by Tahmoor Coal. Fugitive methane emissions will be generated from various sources at the Project site including the following:

- Mine ventilation air;
- Pre-drainage;
- Post-drainage;
- Flaring; and
- Third party power generation (WCMG Power Plant).

Emissions for Scope 1 fugitive emissions were calculated using the following method:

Method 4 – extraction of coal (Division 3.2.2 of the NGER Technical Guidelines).

Greenhouse gas emissions from diesel consumption were estimated using the following equation:

$$E_j = CO_{2-e_{j\,gen\,total}} - \left(Q_{ij,cap} + Q_{ij,flared} + Q_{ijtr}\right)$$

Ej = Fugitive emissions of gas type from extraction of coal ($t\ CO_2$-e)

$CO_{2\text{-}e\ j\ gen,total}$ = Mass of gas type before capture and flaring estimated

		using direct measurement.	(t CO_2-e)
Y_j	=	Factor to convert gas from m^3 at STP to t CO_2-e	
		For methane – $6.784 \times 10^{-4} \times 25$	
		For carbon dioxide – 1.861×10^{-3}	
$Q_{ij,cap}$	=	Quantity of gas captured for combustion	m^3
Qij,flared	=	Quantity of gas flared	m^3
Qijtr	=	Quantity of gas transferred	m^3

[1] GJ = giga joules

[2] kg CO_2-e/GJ = kilograms of carbon dioxide equivalents per gigajoule

The estimated GHG emissions from individual Scope 1 sources by year are presented in Table 4.2 for the scenario where the WCMG Power Plant is operating at Tahmoor.

Table 4.2 Estimated scope 1 emissions for the Project

Year	ROM (tpa)	Scope 1 Emissions from Mine Ventilation Air (t CO_2-e)	Scope 1 Emissions from Pre and Post-Drainage (t CO_2-e)	Scope 1 Emissions from Flares (t CO_2-e)	Scope 1 Emissions from Third Party Power Generation (t CO_2-e)	Total Scope 1 Emissions (t CO_2-e)
2020	313,512	86,873	115,608	35,186	16,034	253,700
2021	1,073,305	110,114	89,680	23,961	24,452	248,207
2022	2,750,008	103,433	100,362	30,210	21,821	255,826
2023	3,553,794	414,978	147,759	63,737	26,467	652,940
2024	3,470,180	413,418	137,138	54,747	20,616	625,918
2025	3,537,991	475,590	181,198	66,995	16,475	740,259
2026	3,603,810	376,391	255,916	83,764	7,622	723,693
2027	3,904,869	633,388	213,766	74,947	9,883	931,985
2028	3,662,208	531,381	833,248	0	4,347	1,368,976
2029	3,379,369	356,786	1,041,960	0	4,327	1,403,072
2030	3,785,148	537,289	894,951	0	3,816	1,436,056
2031	3,511,113	484,500	584,884	0	3,599	1,072,983
2032	3,521,275	375,017	801,264	0	4,006	1,180,287
2033	3,952,712	155,199	234,169	80,368	9,657	479,393
2034	2,600,649	281,624	141,958	47,559	18,419	489,559
2035	1,116,949	467,773	179,008	69,891	19,318	735,991
Total	**47,736,892**	**5,803,754**	**5,952,868**	**631,365**	**210,859**	**12,598,845**

The estimated GHG emissions from individual Scope 1 sources by year are presented in Table 4.3 for the scenario where the WCMG Power Plant is not operating at Tahmoor Mine and this gas is unabated and released directly to the atmosphere.

Table 4.3 Estimated scope 1 emissions for the Project

Year	ROM (tpa)	Scope 1 Emissions from Mine Ventilation Air (t CO_2-e)	Scope 1 Emissions from Pre and Post-Drainage (t CO_2-e)	Total Scope 1 Emissions (t CO_2-e)
2020	313,512	86,873	506,740	593,612
2021	1,073,305	110,114	459,382	569,496
2022	2,750,008	103,433	497,688	601,121
2023	3,553,794	414,978	836,587	1,251,565
2024	3,470,180	413,418	712,633	1,126,051
2025	3,537,991	475,590	818,605	1,294,196
2026	3,603,810	376,391	953,771	1,330,162
2027	3,904,869	633,388	861,559	1,494,948
2028	3,662,208	531,381	523,585	1,054,966
2029	3,379,369	356,786	645,352	1,002,137
2030	3,785,148	537,289	566,438	1,103,727
2031	3,511,113	484,500	383,917	868,417
2032	3,521,275	375,017	508,473	883,489
2033	3,952,712	155,199	921,636	1,076,834
2034	2,600,649	281,624	645,784	927,409
2035	1,116,949	467,773	860,245	1,328,018
Total	**47,736,892**	**5,803,754**	**10,702,395**	**16,506,149**

The above emissions projection assumes that pre-drainage Scope 1 emissions will not occur prior to 2024, and will then continue for the remainder of the project life.

4.3 Fuel consumption – Scope 1 emissions

4.3.1 Diesel

Consumption of diesel oil has been provided by the client through previous years' NGER declarations forms. The total diesel accounted for within the data is equal to diesel used for transport, stationary and non-combustion purposes. It is noted that the Project does not use diesel for transport purposes (i.e. coal transport is the responsibility of a third party). Diesel consumed on-site is used in the following activities:

- Exploration and drilling;
- Extraction of coal (underground); and
- Coal handling.

It is noted that diesel has been used by on-site contractors in previous years for both transport and stationary purposes. The NGER Scheme reporting trigger however has never been met and current contractor diesel consumption is understood to be well below the threshold of 100 TJ of consumed energy. Therefore, it has been assumed that contractor diesel is not a significant source for future years, and is not quantified in this assessment.

Emissions for Scope 1 diesel consumption are calculated using the following method:

Method 1 – emissions of carbon dioxide, methane and nitrous oxide from liquid fuels other than petroleum based oils or greases (Division 2.4.2 of the NGER Determination).

Greenhouse gas emissions from diesel consumption were estimated using the following equation:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1000}$$

Where:

E_{ij}	=	Emissions of GHG from diesel combustion	(t CO_2-e)
Q_i	=	Quantity of fuel	(GJ)[1]
EC_i	=	Energy content of fuel	(GJ/kL)
EF_{ijoxec}	=	Emission factor (Scope 1) for diesel combustion	(kg CO_2-e/GJ)[2]

[1] GJ = giga joules

[2] kg CO_2-e/GJ = kilograms of carbon dioxide equivalents per gigajoule

As described in Section 4.1 above, the quantity of diesel for Project years was estimated using an intensity factor of 0.44 kL of diesel/kt ROM coal.

Scope 1 fuel consumption emissions have been calculated using the energy content and emission factors from Part 3 of the NGER Measurement Determination and are presented in Table 4.4.

Table 4.4 Diesel (for stationary purposes) GHG emission factors – Scope 1

Fuel type	Energy Content (GJ/kL)	Emission factor (kg CO_2-e/GJ)		
		CO_2	CH_4	$N_2$0
Diesel oil	38.6	69.9	0.1	0.2

Source: Schedule 1, Part 3 of the NGER Determination.

The estimated annual and total GHG emissions from diesel usage are presented in Table 4.5.

Table 4.5 Projected diesel fuel consumption and GHG emissions

Year	ROM (tpa)	Estimated Diesel Usage (kL/y)	Scope 1 Emissions (t CO_2-e)
2020	313,512	138	375
2021	1,073,305	474	1,284
2022	2,750,008	1,214	3,289
2023	3,553,794	1,569	4,250
2024	3,470,180	1,532	4,150
2025	3,537,991	1,562	4,231
2026	3,603,810	1,591	4,310
2027	3,904,869	1,724	4,670
2028	3,662,208	1,616	4,380
2029	3,379,369	1,492	4,042
2030	3,785,148	1,671	4,527
2031	3,511,113	1,550	4,199
2032	3,521,275	1,554	4,211
2033	3,952,712	1,745	4,727
2034	2,600,649	1,148	3,110
2035	1,116,949	493	1,336
Total	**47,736,892**	**21,070**	**57,094**

4.3.2 Unleaded petrol

Consumption of Unleaded Petrol (ULP) has been provided by Tahmoor Coal through previous years' NGER declarations forms. ULP is currently used for mining support services at the project site.

Emissions for Scope 1 ULP consumption are calculated using the same method and equation as for diesel in Section 4.3.1.

The quantity of ULP for Project years was estimated using an intensity factor of 0.008 kL of ULP/kt ROM coal.

Scope 1 ULP emissions have been calculated using the energy content and emission factors from Part 3 of the NGER Measurement Determination and are presented in Table 4.6.

Table 4.6 ULP (Gasoline) for transport energy purposes for post-2004 vehicles GHG emission factors – Scope 1

Fuel type	Energy Content (GJ/kL)	Emission factor (kg CO_2-e/GJ)		
		CO_2	CH_4	N_20
Gasoline (other than for use as fuel in an aircraft)	38.6	67.4	0.5	1.8

Source: Schedule 1, Part 3 of the NGER Determination.

The estimated annual and total GHG emissions from diesel usage are presented in Table 4.7.

Table 4.7 Projected ULP consumption and GHG emissions

Year	ROM (tpa)	ULP Usage (kL/y)	Scope 1 Emissions (t CO_2-e)
2020	313,512	2	6
2021	1,073,305	8	22
2022	2,750,008	21	56
2023	3,553,794	28	72
2024	3,470,180	27	70
2025	3,537,991	27	72
2026	3,603,810	28	73
2027	3,904,869	30	79
2028	3,662,208	28	74
2029	3,379,369	26	69
2030	3,785,148	29	77
2031	3,511,113	27	71
2032	3,521,275	27	71
2033	3,952,712	31	80
2034	2,600,649	20	53
2035	1,116,949	9	23
Total	**47,736,892**	**371**	**968**

4.4 Oils and lubricants consumption

Consumption of oils and lubricants (other than petroleum based oil as fuel) is required to be reported within the NGER framework. However, typically oils and lubricants data is used only in terms of characterising the associated energy consumption, as opposed to greenhouse emission. This is since typically such oils and lubricants are consumed below their temperature of combustion, whereby while energy is consumed, there is no associated emission, and these are deemed ‘consumed but not combusted’.

In view of the above discussion, oils and lubricants (other than petroleum based oil as fuel) are not considered further in within the scope of this greenhouse gas assessment.

4.5 Emissions of sulphur hexafluoride gas (SF_6) – Scope 1 emissions

Emissions of SF_6 may be released from the Project site through the use of this gas in insulated switch gear and circuit breaker applications. SF_6 stock has been provided by Tahmoor Coal via previous year’s NGER declaration forms.

Emissions of Scope 1 SF_6 are calculated using the following method:

Method 1 – emissions of hydrofluocarbons and sulphur hexafluoride gases (Section 4.102 of the NGER Determination).

Greenhouse gas emissions from SF_6 is typically estimated using the following equation:

$$E_{jk} = Stock_{jk} \times L_{jk}$$

Where:

E_{jk}	=	Emissions of gas type summed over each equipment type	(t CO_2-e)
$Stock_{jk}$	=	Stock of gas type contained in equipment type	(t CO_2-e)
L_{jk}	=	Default leakage rates for a year of gas type	

The default leakage gas rate as given in the NGER Determination for SF_6 is 0.0089.

As described in Section 4.1, the GHG associated with SF_6 leakage for Project years was estimated using an intensity factor of 0.12 t CO2-e /kt ROM coal.

The estimated annual and total GHG emissions from SF6 are presented in Table 4.8.

Table 4.8 Projected SF6 stocks and GHG emissions

Year	ROM (tpa)	SF6 Stock (t CO_2-e)	Scope 1 Emissions from SF_6 (t CO_2-e)
2020	313,512	39	0.3
2021	1,073,305	133	1.2
2022	2,750,008	341	3.0
2023	3,553,794	440	3.9
2024	3,470,180	430	3.8
2025	3,537,991	438	3.9
2026	3,603,810	446	4.0
2027	3,904,869	484	4.3
2028	3,662,208	454	4.0
2029	3,379,369	419	3.7
2030	3,785,148	469	4.2
2031	3,511,113	435	3.9
2032	3,521,275	436	3.9
2033	3,952,712	490	4.4
2034	2,600,649	322	2.9
2035	1,116,949	138	1.2
Total	**47,736,892**	**5,914**	**53**

4.6 Post-mining activities – Scope 1 emissions

Emissions for Scope 1 post-mining activities are calculated using the following method:

Method 1 – post-mining activities related to gassy mines (Subdivision 3.2.2.4 of the NGER Determination).

This method states the emission factors to be 0.017 t CO_2-e / t ROM coal extracted at the mine.

The estimated annual and total GHG emissions from post-mining activities are presented in Table 4.9.

Table 4.9 Estimated GHG emissions from post-mining activities – Scope 1

Year	ROM (tpa)	Scope 1 Emissions from post-mining activities (t CO_2-e)
2020	313,512	5,330
2021	1,073,305	18,246
2022	2,750,008	46,750
2023	3,553,794	60,414
2024	3,470,180	58,993
2025	3,537,991	60,146
2026	3,603,810	61,265
2027	3,904,869	66,383
2028	3,662,208	62,258
2029	3,379,369	57,449
2030	3,785,148	64,348
2031	3,511,113	59,689
2032	3,521,275	59,862
2033	3,952,712	67,196
2034	2,600,649	44,211
2035	1,116,949	18,988
Total	**47,736,892**	**811,527**

4.7 Electricity consumption – Scope 2 emissions

Consumption of electricity has been provided by Tahmoor Coal via previous years' NGER declaration forms. Electricity consumed on-site is used in the following activities:

- Extraction of coal (underground); and
- Mining support services (including administration);

Emissions for Scope 2 electricity consumption are calculated using the following method:

Method 1 – emissions of carbon dioxide, methane and nitrous oxide from liquid fuels other than petroleum based oils or greases (Division 2.4.2 of the NGER Determination).

GHG emissions from electricity consumption were estimated using the following equation:

$$Y = Q \times \frac{EF}{1000}$$

Where:

Y	=	Scope 2 Electricity emissions	(CO_2-e tonnes)
Q	=	Quantity of electricity purchased from the electricity grid during the year	(kWh/annum)[1]
EF	=	Scope 2 emission factor for the State of Territory in which the consumption occurs	(kg CO_2-e/kWh)[2]

[1] kWh/annum = kilowatt hours per annum

[2] kgCO_2-e/kWh = kilograms of carbon dioxide equivalents per kilowatt hour

As described in Section 4.1, the quantity of electricity for Project years was estimated using an intensity factor of 0.0369 MWh of electricity/t ROM coal.

Scope 2 emissions have been calculated using an emission factor of 0.83 kg CO_2-e/kWh for New South Wales and Australian Capital Territory as sourced from Part 6 of Schedule 1 of the NGER Determination.

The estimated annual and total GHG emissions from electricity usage are presented in Table 4.10.

Table 4.10 Projected electricity consumption and Scope 2 GHG emissions

Year	ROM (tpa)	Electricity Consumption (MWh/y)	Scope 2 Emissions (t CO_2-e)
2020	313,512	11,581	9,613
2021	1,073,305	39,649	32,909
2022	2,750,008	101,588	84,318
2023	3,553,794	131,281	108,963
2024	3,470,180	128,192	106,399
2025	3,537,991	130,697	108,478
2026	3,603,810	133,128	110,497
2027	3,904,869	144,250	119,727
2028	3,662,208	135,286	112,287
2029	3,379,369	124,837	103,615
2030	3,785,148	139,827	116,057
2031	3,511,113	129,704	107,654
2032	3,521,275	130,079	107,966
2033	3,952,712	146,017	121,194
2034	2,600,649	96,071	79,739
2035	1,116,949	41,261	34,247
Total	**47,736,892**	**1,763,449**	**1,463,663**

4.8 Energy production from product coal – Scope 3 emissions

Product coal numbers for the life of the project have been estimated and provided by Tahmoor Coal for this assessment. It is currently anticipated that the majority of product coal (81-97%) will be used as coking coal. The remainder will be used as thermal coal.

Emissions for Scope 3 energy production from product coal are calculated using a similar equation as that referenced in Section 4.3.1.

$$E_{CO2-e} = \frac{Q \times EC \times EF}{1000}$$

Where:

E_{CO2-e} = Emissions of GHG from coal combustion ($t\ CO_2$-e)

Q = Quantity of product coal burnt (t)

EC = Energy Content Factor for bituminous coal (GJ/t)[1]

EF = Emission factor for bituminous coal combustion (kg CO_2-e/GJ)

[1] GJ/t = gigajoules per tonne

Scope 3 emissions have been calculated using the energy content and emission factors from Part 1 of Schedule 1 of the NGER Determination and are presented in Table 4.11.

Table 4.11 Energy production GHG emission factors

Year	Coking Product Coal (Mtpa)	Thermal Product Coal (Mtpa)	Scope 3 Emissions (t CO_2-e)
2020	209,177	16,672	618,071
2021	725,062	58,875	2,145,039
2022	1,803,464	148,776	5,341,094
2023	2,443,127	217,465	7,274,286
2024	2,504,392	303,996	7,654,222
2025	2,620,603	345,505	8,076,159
2026	2,696,760	277,688	8,121,181
2027	2,960,975	286,467	8,871,963
2028	2,686,422	288,909	8,119,980
2029	2,450,883	264,317	7,409,838
2030	2,944,775	263,888	8,772,232
2031	2,556,370	309,373	7,810,812
2032	2,751,048	273,137	8,259,963
2033	2,745,633	269,784	8,236,845
2034	1,817,851	172,317	5,438,160
2035	797,477	82,763	2,403,145
Total	**34,714,018**	**3,579,933**	**104,552,988**

5. SUMMARY OF GHG EMISSIONS

A summary of the annual GHG emissions is provided in Table 5.1.

Table 5.1 Summary of estimated CO_2-e (tonnes) – all scopes

Scope 1 Emissions (t CO_2-e)							Scope 2 Emissions (t CO_2-e)	Scope 3 Emissions (t CO_2-e)
Year	Diesel	Unleaded Petrol	Methane	SF_6	Post-Mining Activities	Total	Electricity	Energy Production
2020	375	6	253,700	0.3	5,330	259,412	9,613	618,071
2021	1,284	22	248,207	1.2	18,246	267,760	32,909	2,145,039
2022	3,289	56	255,826	3.0	46,750	305,924	84,318	5,341,094
2023	4,250	72	652,940	3.9	60,414	717,681	108,963	7,274,286
2024	4,150	70	625,918	3.8	58,993	689,135	106,399	7,654,222
2025	4,231	72	740,259	3.9	60,146	804,712	108,478	8,076,159
2026	4,310	73	723,693	4.0	61,265	789,345	110,497	8,121,181
2027	4,670	79	931,985	4.3	66,383	1,003,121	119,727	8,871,963
2028	4,380	74	1,368,976	4.0	62,258	1,435,692	112,287	8,119,980
2029	4,042	69	1,403,072	3.7	57,449	1,464,636	103,615	7,409,838
2030	4,527	77	1,436,056	4.2	64,348	1,505,012	116,057	8,772,232
2031	4,199	71	1,072,983	3.9	59,689	1,136,946	107,654	7,810,812
2032	4,211	71	1,180,287	3.9	59,862	1,244,435	107,966	8,259,963
2033	4,727	80	479,393	4.4	67,196	551,401	121,194	8,236,845
2034	3,110	53	489,559	2.9	44,211	536,936	79,739	5,438,160
2035	1,336	23	735,991	1.2	18,988	756,339	34,247	2,403,145
Total	**57,094**	**968**	**12,598,845**	**53**	**811,527**	**13,468,487**	**1,463,663**	**104,552,988**

6. GHG EMISSIONS INTENSITY

The estimated Scope 1 GHG emissions intensity of the Proposal is approximately 0.35 t CO_2 e/t saleable coal. The estimated emissions intensity of the Proposal is comparable with the emissions intensity of existing gassy underground coal mines in Australia (Deslandes, 1999).

Figure 6.1 (derived from Deslandes, 1999) shows the GHG intensity of the Proposal compared to other Australian coal mines. The emissions intensity is within the range for gassy underground mines.

By far the largest source of scope 1 GHG emissions are fugitive methane emissions (93.5%) followed by emissions from post-mining activities (6.0%) (refer Table 5 1).

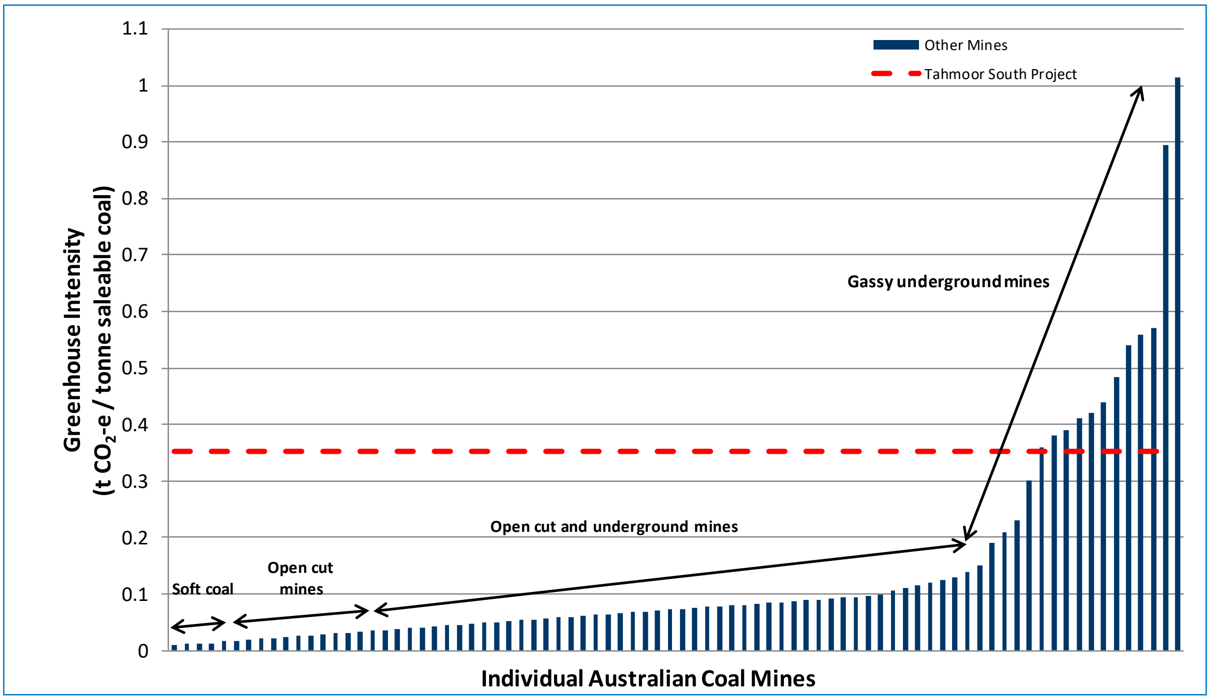


Figure 6.1: GHG intensity comparison

7. ENVIRONMENTAL IMPACT

According to the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report, global surface temperature has increased by 0.89ºC ± 0.2ºC during the 100 years ending 2012 (IPCC, 2013). The IPCC has determined "most of the observed increase in globally averaged temperatures since the mid-twentieth century is very likely due to the observed increase in anthropogenic greenhouse gas concentrations". "Very likely" is defined by the IPCC as greater than 90% probability of occurrence (IPCC, 2013).

Climate change projections specific to Australia have been determined by the CSIRO and the Australian Bureau of Meteorology (BoM), based on global emissions scenarios predicted by the latest IPCC assessment (CSIRO, 2015a). These projections supersede those released by CSIRO and the BoM in 2007. Although the findings are similar to those of the 2007 projections, the range of emissions scenarios is broader than those used for the 2007 projections. The latest projections begin with concentration levels, rather than socio-economic assumptions followed by inferred emissions.

The projected changes have been prepared for four Representative Concentration Pathways (RCPs), which represent the following scenarios of emissions of greenhouse gases, aerosols and land-use change:

- RCP8.5 (high emissions) - represents a future with little curbing of emissions, with CO2 concentrations continuing to rapidly rise, reaching 940 parts per million (ppm) by 2100.
- RCP6.0 (intermediate emissions) - represents lower emissions, achieved by application of some mitigation strategies and technologies. This scenario results in the CO2 concentration rising less rapidly than RCP8.5, but still reaching 660ppm by 2100.
- RCP4.5 (intermediate emissions) - represents a similar scenario to RCP6.0, but emissions peak earlier (around 2040), and the CO2 concentration reaches 540ppm in 2100.
- RCP2.6 (low emissions) - assumes a very strong emissions reductions from a peak at around 2020 to reach a CO2 concentration at about 420ppm by 2100. This pathway would require early participation from all emitters, including developing countries, as well as the application of technologies for actively removing carbon dioxide from the atmosphere.

For climate change projections, a regionalisation scheme using natural resource management regional boundaries has been used to divide Australia up into 8 clusters and 15 sub-clusters. For the projections described above, Table 7.1 presents the changes in annual temperature relative to the 1986-2005 period for the East Coast sub-cluster where the Project is located.

Table 7.1 Projected changes in annual temperature (relative to the 1986-2005 period)

2030 – RCP2.6 (low emissions scenario)	2030 – RCP4.5 (intermediate emissions scenario)	2030 – RCP8.5 (high emissions scenario)	2090 – RCP2.6 (low emissions scenario)	2090 – RCP4.5 (intermediate emissions scenario)	2090 – RCP8.5 (high emissions scenario)
Temperature (ºC)					
0.8 (0.4 to 1.1)	0.9 (0.6 to 1.2)	1.0 (0.6 to 1.3)	0.9 (0.5 to 1.5)	1.9 (1.3 to 2.5)	3.7 (2.7 to 4.7)

Notes: The table gives the median (50th percentile) change with the 10th and 90th percentile range given within brackets.
Source: CSIRO (2015b) Climate Change in Australia – Projections for Australia's NRM Regions – East Coast Cluster Report, Commonwealth Scientific and Industrial Research Organisation.

The CSIRO also details projected changes to other meteorological parameters (for example rainfall, potential evaporation, wind speed, relative humidity and solar radiation) and the predicted changes to the prevalence of extreme weather events (for example droughts, bush fires and cyclones).

The potential social and economic impacts of climate change to Australia are detailed in the Garnaut Climate Change Review (Garnaut, 2008), which draws on IPCC assessment work and the CSIRO climate projections. The Garnaut review details the negative and positive impacts associated with predicted climate change with respect to:

- Agricultural productivity.
- Water supply infrastructure.
- Urban water supplies.
- Buildings in coastal settlements.
- Temperature related deaths.
- Ecosystems and biodiversity.
- Geopolitical stability and the Asia Pacific region

The Project's contribution to projected climate change, and the associated impacts, would be in proportion with its contribution to global GHG emission. Average annual scope 1 emissions from the

Project (0.84 Mt CO_2-e) would represent approximately 0.19% of Australia's commitment under the Paris Agreement (431 Mt CO_2-e by 2030) and a very small portion of global greenhouse emissions, given that Australia contributed approximately 1.5% of global GHG emissions in 2005 (Commonwealth of Australia, 2011).

A comparison of predicted annual GHG emissions from the Project with global, Australian and NSW emissions inventories are presented in Table 7.2.

Table 7.2 Comparison of greenhouse gas emissions

Geographic coverage	Source coverage	Timescale	Emission Mt CO_2-e	Reference
Project	Scope 1 only	Average annual	0.84	This report.
Global	Consumption of fossil fuels	Total since industrialisation 1750 - 1994	865,000	IPCC (2007a). Figure 7.3 converted from Carbon unit basis to CO_2 basis. Error is stated greater than ±20%.
Global	CO_2-e emissions	2005	35,000	Based on Australia representing 1.5% of global emissions (Commonwealth of Australia, 2011). Australian National Greenhouse Gas Inventory (2005) taken from http://www.ageis.greenhouse.gov.au/
Global	CO_2-e emission increase 2004 to 2005	2005	733	IPCC (2007a).From tabulated data presented in Table 7.1 on the basis of an additional 733 Mt/a. Data converted from Carbon unit basis to CO_2 basis.
Australia	1990 Base	1990	547.7	Taken from the National Greenhouse Gas Inventory (2009) http://www.ageis.greenhouse.gov.au/
Australia	Kyoto target	Average annual 2008 - 2012	591.5	Based on 1990 net emissions multiplied by 108% Australia's Kyoto emissions target.
Australia	Paris Agreement	2030	431	Based on Australia's emission target for 2030 (https://climateactiontracker.org/countries/australia/)
Australia	Total	2015	537.9	Taken from the National Greenhouse Gas Inventory (2017) http://ageis.climatechange.gov.au/#
NSW	Total	2011	133.4	Taken from the National Greenhouse Gas Inventory (2017) http://ageis.climatechange.gov.au/#

The commitment from the Australian Government to reduce GHG emissions is proposed to be achieved through the introduction of the Australian Government's proposed Direct Action Plan. This would involve a 'baseline and credit' approach whereby businesses that reduce their emissions below their baseline have the opportunity to offer abatement for sale to the government (LPA, 2010).

8. GHG MANAGEMENT AND MITIGATION

8.1 Reasonable and feasible potential management measures and controls

An evaluation has been completed as to reasonable and feasible measures to minimise GHG emissions from the project. A number of options were evaluated to determine those that were feasible from those that were not achievable. Fundamentally, the reduction of fugitive methane emissions by both flaring and, if available, diversion of waste mine gas to the WCMG Power Plant is considered to be best practice methane management for underground coal mining operations. Given that Tahmoor Coal have determined these practices as both reasonable and feasible, other less effective measures were not evaluated further.

In view of the forgoing, Tahmoor Coal will commit to implementing a number of reasonable and feasible measures to minimise GHG emissions from the Project. Recommended measures are described Table 8.1.

The effectiveness of these reasonable and feasible measures to reduce GHG emissions (and energy consumption) will be monitored, as Tahmoor Coal will annually estimate GHG emissions and energy consumption in accordance with National Greenhouse and Energy Reporting and Energy Efficiency Opportunities requirements.

Table 8.1 Recommended mitigation measures

Type of Mitigation	Description
Creation of mine plan	Maximising energy efficiency is a key consideration in the development of the mine plan. For example, significant savings of GHG emissions (through increased energy efficiency) can be achieved by mine planning decisions which minimise haul distances and therefore fuel use.
Mining operations	Reducing fugitive methane emissions using the following abatement measures: • Flaring. • Methane recycled through third party power generation (WCMG Power Plant), if available. • Use of ventilation control devices in sections of the mine not in use enabling them not to be ventilated (unless required for safety purposes), thereby reducing fugitive emissions). Use of electric winder, not diesel transport, as the primary method of materials transport for the mine. Sealing of panels to reduce methane emissions from the goaf. Use of ventilation control devices in sections of the mine not in use enabling them not to be ventilated (unless required for safety purposes), thereby reducing fugitive emissions.
Monitoring	Use of real-time gas (methane and carbon dioxide), temperature, pressure and associated volumetric flow monitoring at the ventilation shaft site to allow accurate measurement of ventilation (including methane and carbon dioxide) emissions, which will then allow further feasibility assessment of reuse options. Monitoring options are further detailed in Section 8.2 below.
Recording	Ensuring maintenance, calibration and record keeping is undertaken on the main ventilation shaft and fans to allow calculation of greenhouse gas emissions. Maintaining records for monthly electricity use and monthly ROM coal production to allow calculation of greenhouse gas emissions.
Management Plans	Prepare an Energy Savings Action Plan in accordance with the Guidelines for Energy Savings Action Plans (DEUS, 2005). The plan will include standards to minimise energy use and GHG emissions from the Project's operations. The plan will include objectives, commitments, procedures and responsibilities for: • Assisting in researching and promoting low emission coal technologies. • Improving energy use and efficiency. • Considering of the use of alternative fuels where economically and practically feasible. • Review of mining practices to minimise doubling handling of materials and ensuring that materials haulage is undertaken using the most efficient routes. • Ongoing scheduled and preventative maintenance to ensure that diesel and electricity powered plants operate efficiently. • Develop targets for greenhouse gas emissions and energy use and monitor and report against these. • Implementation of a detailed energy monitoring programme. This would include monitoring the electricity and diesel usage on-site to identify main sources of greenhouse gas emissions and apply appropriate reduction mechanism where possible. • Regular maintenance of diesel powered equipment to ensure operation at peak efficiency. • Conduct baseline study of energy use. • Assess lighting plant efficiency.

8.2 Monitoring

A Continuous Emission Monitoring (CEM) is currently in place at the Tahmoor Mine. A similar system will be installed for the Tahmoor South Project.

It is intended that the system meet the requirements of Method 4 (direct measurement of emissions of GHGs) as described within Part 1.3 of the NGER Measurement Determination. Division 1.3.1 of Part 1.3 of the NGERs Determination states that:

> Method 4 required the direct measurement of emissions released from the source from the operation of a facility during a year by monitoring the gas stream at a site within part of the area (for example, a duct or stack) occupied for the operation of the facility.

The system will include various instrumentation located at the upcast vent shafts to measure key parameters including:

- Pressure of the gas stream in kilopascals (kPa);
- Flow rate of the gas stream in cubic metres per second (m3/s);
- Proportion of methane and carbon dioxide in the volume of the gas stream (v/v); and
- Temperature in Kelvin (K).

The above parameters are required to be captured during each measurement time step to calculate the mass emission rates for CH_4 and CO_2 consistent with equation 1.21(1) of the NGER Technical Guidelines.

8.2.1 Standards for continuous emission monitoring

To meet the requirements of Method 4 monitoring within Part 1.3 of the NGER Measurement Determination, the monitoring described above must be conducted in accordance with the following standards:

8.2.1.1 Selection of sampling positions

The location of sampling positions for the CEM equipment in relation to the gas stream must be selected in accordance with one of the following standards:

- AS 4323.1—1995 Stationary source emissions - Selection of sampling positions;
- AS 4323[1].1—1995 Amdt 1-1995 Stationary source emissions - Selection of sampling positions;
- ISO 10396:2007 Stationary source emissions - Sampling for the automated determination of gas emission concentrations for permanently-installed monitoring systems;
- ISO 10012:2003 Measurement management systems - Requirements for measurement processes and measuring equipment; or
- USEPA – Method 1 – Sample and Velocity Traverses for Stationary Sources (2000).

8.2.1.2 Flow rate

Monitoring of the volumetric flow rates of the gas stream must be undertaken in accordance with one of the following standards:

- ISO 10780:1994 Stationary source emissions — Measurement of velocity and volume flowrate of gas streams in ducts;
- ISO 14164:1999 Stationary source emissions — Determination of the volume flowrate of gas streams in ducts - Automated method;

- USEPA Method 2 Determination of Stack Gas Velocity and Volumetric flowrate (Type S Pitot tube) (2000); or
- USEPA Method 2A Direct Measurement of Gas Volume Through Pipes and Small Ducts (2000).

8.3 Gas concentration

The concentrations of methane and carbon dioxide in the gas stream must be undertaken in accordance with one of the following standards:

- USEPA Method 3A Determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (instrumental analyzer procedure) (2006);
- USEPA Method 3C Determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources (1996); or
- ISO 12039:2001 Stationary source emissions — Determination of carbon monoxide, carbon dioxide and oxygen — Performance characteristics and calibration of automated measuring system.

All monitoring equipment should be included within the site's maintenance management system. This is to ensure that all components of the CEM remain within calibration.

Recommendations made within ACARP report C8061 (Mark et al, 2001) state that equipment should be accurate to 0.05% gas concentration to meet a requirement to report greenhouse gas emissions to 5 percent accuracy.

9. CONCLUSION

ERM has been commissioned by Tahmoor Coal to complete a Greenhouse Gas assessment for the Tahmoor South Project. The assessment will form a component of the Environmental Impact Statement for the Project.

The Project's main source of GHG emissions include fugitive methane from mine ventilation, pre and post-drainage and flaring. Other Scope 1 and 2 emissions include diesel, unleaded petrol consumption, post-mining activities, electricity use and use of SF_6. The only Scope 3 emissions presented for the Project relates to energy use to produce both thermal and coking coal.

It was found that the Project's contribution to projected climate change, and the associated impacts, would be in proportion with its contribution to global GHG emissions. Average annual Scope 1 emissions from the Project (0.84 million tonnes [Mt] CO_2-e) would represent approximately 0.19% of Australia's commitment under the Paris Agreement (431 Mt CO_2-e) and a very small portion of global greenhouse emissions.

Tahmoor Coal will employ a number of mitigation measures at the Project site to minimise the generation of GHG emissions. Such measures will include fugitive methane abatement such as the use of flares and, if available, recycling through a WCMG Power Plant and Continuous Emissions Monitoring of fugitive emissions.

10. REFERENCES

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