BDM RESOURCES

MINING ENVIRONMENT AGRICULTURE COMMUNITIES

Centennial Coal

Mandalong Southern Extension Project (MLS) Greenhouse Gas Report for EIS

This report utilises data provided by Centennial, Morvent Pty Ltd and Corky's Carbon and Combustion Pty Ltd to calculate greenhouse gas (GHG) emissions associated with the Mandalong Southern Extension Project. BDM Resources assume no liability for the accuracy of the input data.

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Shortened Forms

ACCU	Australian Carbon Credit Units
AGEIS	Australian Greenhouse Emission Information System
CDM	Clean Development Mechanism
CEF	Clean Energy Future
CER	Carbon Emission Reductions
CFC	chlorofluorocarbon
CFI	Carbon Farming Initiative
CMATSP	Coal Methane Abatement Technology Support Package
DA	development approval
DCCEE	Department of Climate Change and Energy Efficiency
DEUS	Department of Energy, Utilities and Sustainability
DGRs	Director General's Requirements
EEO	Energy Efficiency Opportunities
EIS	Environmental Impact Statement
EL	exploration lease
EP&A Act	Environmental Planning and Assessment Act
ESAP	Energy Savings Action Plans
GHG	greenhouse gas
GWP	Global Warming Potential
HFC	hydrofluorocarbon
IPCC	Intergovernmental Panel on Climate Change
JI	Joint Implementation
LOM	life-of-mine
Mtpa	million tonnes per annum
NGA	National Greenhouse Accounts
NGER	National Greenhouse and Energy Reporting
RET	Renewable Energy Target
ROM	run-of-mine
RTO	reverse thermal oxidiser
STP	standard temperature and pressure
UNFCCC	United Nations Framework Convention on Climate Change
VAM	ventilation air methane

1.0 Executive Summary

The Mandalong Southern Extension Project (the Project) represents a new coal mining development proposed as an extension to the existing Mandalong Mine. Mandalong Mine is owned and operated by Centennial Mandalong Pty Limited (Centennial Mandalong) a wholly owned subsidiary of Centennial Coal Company Limited (Centennial).

Mandalong Mine has approval to extract up to 6 Mtpa of coal for supply to domestic and export markets. The Project is assumed to continue to operate Mandalong Mine within the Project area at a maximum production of 6 Mtpa.

Centennial Mandalong is seeking approval to continue the Mandalong Mine underground coal mining operations using a combination of continuous miner and longwall methods. The underground mining of coal in gas bearing strata will require pre-drainage of methane (CH_4) from the coal seam to allow mining to be conducted safely. In addition, ventilation of the mine for safety purposes will result in release of methane in the form of "ventilation air methane" (VAM). The emission of methane as pre-drainage (concentrated) gas or VAM, together with other gases including carbon dioxide (CO_2), are greenhouse gases (GHGs) referred to as "fugitive emissions".

In addition to fugitive emissions, other sources of GHG emissions relevant to the Project include diesel use, imported electricity (scope 2), and product combustion (scope 3).

It has been calculated that the maximum total emissions relating to the Project are 1,813,664 t CO_2-e pa (scope 1 and 2). This represents the maximum GHG emissions per annum, assuming full production of 6 Mtpa and maximum gas emissions. The maximum projected scope 1 and 2 emissions over the life of the mine (25 years) are 45,038,008 t CO_2-e.

The estimated maximum annual emissions are:

- VAM - 1,274,035 t CO_2-e pa
- Pre-drainage gas - 429,837 t CO_2-e pa
- Electricity use - 107,152 t CO_2-e pa
- Diesel combustion - 2,640 t CO_2-e pa

These emissions will be reduced through abatement or avoidance activities as follows:

- Gas engines/flares - 377,658 t CO_2-e pa abated
- Electricity emissions - 56,274 t CO_2-e pa avoided

The pre-drainage gas will be piped underground from the Project area to the existing Mandalong Mine Access Site where approval has already been granted (DA 97/800 Mod 4) for the construction and operation of up to 12 MW_e total capacity of gas engines. Mandalong Mine is currently constructing a gas flare for combusting methane at the Mandalong Mine Access Site in accordance with current approvals (DA 97/800 Mod 3) and this will be operational for the Project.

The combustion of pre-drainage gas through flares and engines at Mandalong Mine will reduce the scope 1 emissions by 377,658 t CO_2-e pa. This equates to the abatement of approximately 22% of total annual emissions. In addition, the electricity generated will reduce scope 2 emissions by 56,274 t CO_2-e pa which equates to a reduction of approximately 53% of annual scope 2 emissions.

The most significant emission is associated with VAM. A peak flow of mine ventilation air of approximately 500 m^3 sec^{-1}, comprising an average of approximately 0.46% methane, yields a total emission per annum of 1,274,035 t CO_2-e. There is currently no proven efficient, cost-effective and safe technology to abate VAM in coal mines. Research on reverse thermal oxidiser (RTO) technology is the most advanced; however there are safety concerns that exist with integration of an RTO to a coal mine. The combination of unproven technology and no regulatory approval for direct coupling of any technology to a working coal mine in Australia means that VAM abatement is not considered feasible at this stage.

However, a trial of a ventilation air methane – regenerative afterburner (VAM-RAB) developed by Corky's Carbon and Combustion is being undertaken at Mandalong Mine. The demonstration VAM-RAB is currently under construction with the aim to commence trials in 2013.

Under the Federal Governments Clean Energy Future (CEF) legislation, Centennial Mandalong is liable for all residual emissions after abatement activities. Calculated liable emissions of 1,328,853 t CO_2-e pa can be offset or will be subject to the carbon pricing mechanism or "carbon tax". Where offsets are available and cost-effective, Centennial Mandalong will purchase only from registered suppliers under the relevant domestic or international certification scheme (the latter from July 2015 onwards).

The implication of gas engines and flares being sited at the Mandalong Mine under the existing approval, together with the lack of acceptable solution for VAM abatement in the short term means that consideration of additional surface infrastructure is not required for GHG abatement under the Project Environmental Impact Statement (EIS).

2.0 Project Background

Centennial Mandalong Pty Ltd (Centennial Mandalong) is seeking approval for the Mandalong Southern Extension Project (the Project) under Part 4 Division 4.1 of the Environmental Planning and Assessment Act 1979 (EP&A Act). Specifically the Project proposes to:

- Continue the Mandalong Mine underground mining operations into the area covered by EL 6317 using a combination of continuous miner and longwall mining methods;
- Extract up to 6 Mtpa of run-of-mine (ROM) coal from the West Wallarah and Wallarah-Great Northern Seams within the current mining lease areas and the area covered by EL 6317;
- Deliver ROM coal from the underground workings to the Cooranbong Entry Site at a rate of up to 6 Mtpa and to the Delta Entry Site at a rate of up to 6 Mtpa;
- Continue to utilise the existing surface infrastructure of the Mandalong Mine Access Site and Delta Entry Site;
- Install and operate additional surface infrastructure for mine ventilation, storage and underground delivery of stone dust, concrete and ballast, hydrocarbon storage, electrical reticulation, water reticulation, water management, communications and other ancillary services and activities;
- Transfer water between the water management systems of Mandalong Mine, Newstan Colliery and Awaba Colliery;
- Increase manning to 420 full-time employees and up to 50 contractors during longwall relocations;
- Undertake on-going exploration drilling activities within the bounds of Centennial Mandalong's mining leases and exploration licences;
- Increase the life-of-mine to 25 years from the granting of a mining lease(s) over EL 6317; and
- Continue to operate 24 hours per day, seven days per week.

The Project is an extension to the existing Mandalong Mine operations. Mandalong Mine is owned and operated by Centennial Mandalong a wholly owned subsidiary of Centennial.

In parallel to the development of this Project, Centennial is seeking approval for a new underground mine at Newstan Colliery (Newstan Colliery – Extension of Mining Project). In addition, an approval is being sought for expansions to and upgrades of coal handling and transport facilities to more efficiently handle, process and transport coal produced from the Newstan Colliery and Mandalong Mine as part of the Northern Coal Services – Coal Logistics Project. Thus, there are significant overlaps between this Project and others being developed concurrently. Operational boundaries have been established as illustrated in Figure 1 to allow clear Project distinction.

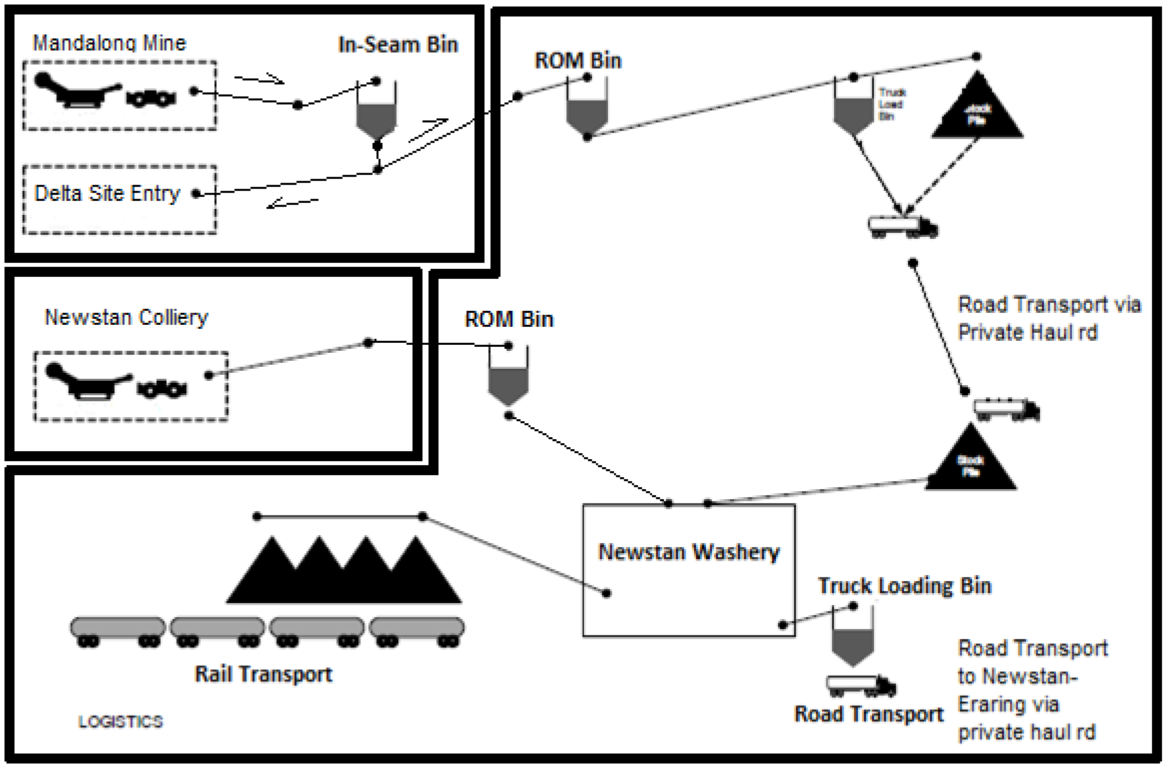

Figure 1 GHG inventory boundaries between the three concurrent northern Centennial projects

3.0 Greenhouse Gases Overview

3.1 Climate Change

Climate change is a change in either or both of the average pattern of weather or extremes around the average conditions over periods ranging from decades to millions of years. There is clear evidence that our climate is changing, largely due to human activities. The Fourth Assessment Report, produced by the Intergovernmental Panel on Climate Change (IPCC) in 2007, states global warming is 'unequivocal' and 'most of the observed increase in globally-averaged temperatures since the mid-20th century is very likely due to the observed increase in greenhouse gas concentrations'. As such there is growing pressure on industry to reduce emissions in order to reduce the effects of climate change.

In Australia the largest GHG emitters are required to account for GHG emissions under the National Greenhouse and Energy Reporting Act 2007 (NGER Act). The NGER Act is a single national framework for the reporting and dissemination of information about the GHG emissions, GHG projects, and energy use and production of corporations.

3.2 Greenhouse Gases

The main GHG created directly by human activities are carbon dioxide, methane, nitrous oxide, ozone, and synthetic gases, such as chlorofluorocarbons (CFC) and hydrofluorocarbons (HFC). In accounting and preparing a GHG inventory there are six GHG's covered by the Kyoto Protocol. Each of these has a different Global Warming Potential (GWP).

Table 1 Greenhouse warming potentials - select greenhouse gases

Greenhouse Gas	Global Warming Potential*
Carbon dioxide (CO_2)	1
Methane (CH_4) pre-2017	21
Methane (CH_4) 2017 onwards	25^
Nitrous oxide (N_2O)	310
Sulphur hexafluoride (SF_6)	23,900
*GWP factors specified for calculating emissions under Kyoto accounting provisions Source: NGA Factors, July 2012	

^GWP for CH4 will increase to 25 from the year 2017 onwards (DCCEE, 2012)

The GWP is defined as an index representing the combined effect of the differing times GHGs remain in the atmosphere and their relative effectiveness in absorbing outgoing infrared radiation.

3.3 Scope of Emissions

Greenhouse gas emissions are described in terms of scope 1, scope 2 and scope 3 emissions.

3.3.1 Scope 1

Scope 1 emissions refer to the emissions that occur as a direct result of the Project activities. These include fuel combustion on site for stationary or transport purposes, fugitive emissions and use of HFCs and others.

3.3.2 Scope 2

Scope 2 emissions generally refer to the emissions resulting from the importation of steam or electricity. In Australia this is primarily from coal fired power generation.

3.3.3 Scope 3

Scope 3 emissions refer to the emissions resulting from the consumption of the firm's products, contractor emissions and employee travel. The scope 3 emissions are generally scope 1 or 2 emissions for other companies. For example, in general, diesel use by contractors is a scope 3 emission, yet is referred to as a scope 1 emission in the GHG inventory of the contractor. For the Project, it is important to note that all contractor diesel used for development mining is included as a scope 1 emission of the Project as these diesel emissions are incurred in the direct production of the company's product. Combustion of coal to produce electricity will result in a scope 1 emission at the power station or a scope 2 emissions for industry or householders.

3.4 Greenhouse Gas Accounting Method

Direct accounting for GHG emissions at the emission source is difficult, expensive and time-consuming in many cases. As such there are four methods that can be used to account for GHG emissions. These methods are briefly outlined below:

- **Method 1:** In its simplest form, GHG emissions may be calculated by utilising "emission factors" and "activity data".
- **Method 2:** GHG emissions calculated from activity data and emissions factors as in method 1 however the key difference is the data and factors utilised in method 2 are more site specific and not national averages as used in method 1.
- **Method 3:** GHG calculations are based on emission factors and activity data obtained from sampling and analysing source material. Methods 1 and 2 rely upon national or regional averages whereas method 3 GHG determinations are based on site specific data from feedstock analysis.
- **Method 4:** GHG emission estimates are derived from routine direct measurement of point source emissions.

3.4.1 Activity Data

Activity data is site specific and it quantifies a GHG emitting activity in units that help calculate the emissions generated. By utilising activity data and emission factors, GHG emissions can be estimated.

3.4.2 Emissions Factors

Emission factors are activity specific and are published annually by the Department of Climate Change and Energy Efficiency (DCCEE) as the National Greenhouse Accounts (NGA) Factors. Activity specific emission factors coupled with the methodology set out by the NGER (Measurement) Determination 2008 can be used to estimate GHG emissions from specific activities such as fuel combustion or electricity importation.

3.5 Principles of GHG Reporting

Estimates of GHG emissions and energy production and consumption must be prepared in accordance with the principles set out in section 1.13 of the NGER (Measurement) Determination 2008. These principles are:

- **RELEVANCE -** Ensure the GHG inventory appropriately reflects the GHG emissions of the company and serves the decision-making needs of users – both internal and external to the company.

- **COMPLETENESS -** Account for and report on all GHG emission sources and activities within the chosen inventory boundary. Disclose and justify any specific exclusions.

- **CONSISTENCY -** Use consistent methodologies to allow for meaningful comparisons of emissions over time. Transparently document any changes to the data, inventory boundary, methods, or any other relevant factors in the time series.

- **TRANSPARENCY -** Address all relevant issues in a factual and coherent manner, based on a clear audit trail. Disclose any relevant assumptions and make appropriate references to the accounting and calculation methodologies and data sources used.

- **ACCURACY -** Ensure that the quantification of GHG emissions is systematically neither over nor under actual emissions, as far as can be judged, and that uncertainties are reduced as far as practicable. Achieve sufficient accuracy to enable users to make decisions with reasonable assurance as to the integrity of the reported information.

Additional to the principles of GHG reporting, data materiality can be used to simplify the accounting process by omitting low level emission sources which do not make a significant contribution to overall Project emissions. Emissions which are within emission reporting errors or make up less than 5% or of the total Project emissions are deemed to be immaterial as their inclusion or omission does not have significant bearing on Project behaviours or processes (NGA Guidelines, 2008, pg 32).

4.0 GHG and Climate Change Policy and Regulation

Australia ratified the Kyoto Protocol (the Protocol) in 2007 and as such made a commitment to reducing GHG emissions. In response to this ratification Australia adopted a number of Federal and State Government initiatives to achieve a reduction in GHG emissions to 5% below 1990 levels.

Based on the NGER (Measurement) Determination 2008, the Project is deemed a significant producer of GHG emissions (>25 kt CO_2-e pa). Scope 1 emissions for the Project are liable under the Federal Government carbon pricing mechanism, the CEF Legislation. Currently the emissions liability "carbon tax" is applied at a rate of $23 per t CO_2-e emitted. Alternative to paying a tax on carbon emissions, opportunities exist to abate and/ or avoid emissions. There are varying possibilities with regards to off-setting emissions over time from both Australian and international projects.

4.1 International Policy

4.1.1 Kyoto Protocol

The Kyoto Protocol is an international agreement linked to the United Nations Framework Convention on Climate Change (UNFCCC). The major feature of the Kyoto Protocol is that it sets binding targets for 37 industrialised countries and the European community for reducing GHG emissions. These targets amount to an average of five per cent reduction against 1990 levels over the five-year period 2008-2012.

Countries must meet their targets primarily through national measures to avoid, abate or offset GHG emissions. However, the Kyoto Protocol offers them an additional means of meeting their targets by way of market-based mechanisms:

- **Emissions trading:** Gives corporations or individuals the opportunity to offset their GHG emission liability by purchasing Kyoto certified carbon credits generated by carbon emission reduction projects.
- **Clean Development Mechanism (CDM):** Where industrialised (or "Annex One" as defined in the Protocol) nations can implement Kyoto approved GHG reduction projects in developing nations (or "Non-Annex One" as defined in the Protocol) in order to generate Carbon Emission Reductions.
- **Joint Implementation (JI):** Allows developed (Annex One) nations to engage in emission reduction projects with other developed (Annex One) nations to generate Certified Emission Reductions (CERs).

These mechanisms help stimulate investment in GHG-friendly actions and technologies and to meet emission targets in a cost-effective manner. Comprehensive mechanisms have been set up under the UNFCCC that aim to ensure the validity and credibility of emissions avoidance, abatement and offset projects under the CDM and JI.

4.2 Australian Policy and Regulation

4.2.1 National Greenhouse and Energy Reporting (NGERs)

The NGER Act 2007 provides a single national framework for the reporting and dissemination of information about the GHG emissions, GHG projects, and energy use and production of corporations. Corporations that trigger relevant reporting thresholds are required to report under NGERs.

Centennial triggered NGERs thresholds since the commencement of the programme and has reported GHG emissions, energy consumption and energy production since 1 July 2008.

4.2.2 Australia's CEF Package

The Australian Government has legislated to reduce Australia's net contribution to global GHG emissions. This legislation is consistent with the Kyoto Protocol and is implemented under a suite of actions referred to as the Clean Energy Future Package (CEF Package). The primary aspect of this is placing a price on carbon (carbon pricing mechanism).

Facilities emitting greater than 25 kt CO_2-e of prescribed emissions are liable entities under the CEF Package. Liable entities can reduce the carbon tax that they will have to pay for their GHG emissions by either abating the emissions or off-setting them.

4.2.3 Carbon Pricing

Australia's carbon pricing system will be implemented in two phases. The first phase takes shape in the form of a fixed price domestic emissions trading market which is active from the 1 July 2012 to 30 June 2015. During the second phase from 1 July 2015 onwards, the Australian carbon market will be extended and linked to the European carbon market (Media Release, DCCEE, August 2012).

During the fixed price phase (or the first phase) a carbon price will apply to all liable entities for all emissions generated at a rate of $23 AUD / t CO2-e. This price will be indexed at 2.5% per year.

Australia's carbon pricing mechanism will be linked to the European carbon market from 1 July 2015. This will initially take place via an interim link followed by the development of a full two way link no later than 1 July 2018. This will allow mutual compliance of all tradeable credits under both Australian and European systems.

During the second phase, a floor carbon price will not be implemented, instead a "sub limit" will be established which allows Australian entities to offset up to 50% of their liabilities through purchasing international units, however only 12.5% of total liabilities can be met by Kyoto units.

4.2.4 Emissions Offsets

During the fixed price period off-setting is limited to 5% of the total liability of an entity. These offsets must be Kyoto compliant and sourced domestically.

During the interim link period of international trading post 1 July 2015, emitters may purchase offsets up to 50% of the total liability from eligible international units as is further discussed below.

4.2.5 Carbon Farming Initiative

The CFI is the carbon offsets scheme component of the CEF Package. Legislation to underpin the CFI was passed on 23 August 2011. The CFI allows farmers and land managers to earn carbon credits by storing carbon or reducing GHG emissions on the land. These credits can then be sold to individuals and businesses wishing to offset their emissions.

4.2.6 International Linking

Australia's carbon pricing mechanism will be linked to international carbon markets from 1 July 2015 via an interim link. The interim link will be in effect while formal negotiations proceed towards the establishment of a full two way trading link. The interim link will allow Australian businesses to purchase European allowances for future compliance in Australia. The development of the full two way link will occur no later than 1 July 2018.

The aim of international linking between European and Australian carbon markets is to provide Australian entities with access to a larger market for cost-effective emission reductions and provide European market participants with enhanced business opportunities.

4.2.7 Clean Energy Regulator

The Clean Energy Regulator administers the carbon pricing mechanism, NGER, CFI and the Renewable Energy Target (RET).

4.2.8 Energy Efficiency Opportunities (EEO)

The EEO program encourages large energy-using businesses to improve their energy efficiency. It does this by requiring businesses to identify, evaluate and report publicly on cost-effective energy savings opportunities. Legislation to support EEO came into effect in 2006. Under the CEF Package, the Australian Government announced it would extend the EEO program to include green fields and expansion projects. Participation in EEO is mandatory for corporations that use more than 0.5 petajoules (PJ) of energy per year, approximately 139 GWh (New South Wales State Policy).

4.2.9 Energy Savings Actions Plans

In 2005 the NSW state government introduced mandatory reporting requirements for large energy users (Energy Savings Order 2005, dated 25/10/05). This required preparation of Energy Savings Action Plans (ESAP) by facilities that were specifically identified. ESAPs do not apply to greenfield sites or to major extensions of existing sites as such but are commonly required by virtue of development consent conditions. Mandalong Mine has had an ESAP since the commencement of the scheme.

4.2.10 Environmental Planning and Assessment Act 1979

The EIS for the development is required to meet content requirements under clauses 6 and 7 of schedule 2 of the Environmental Planning and Assessment Regulation 2000. In accordance with the Director General's Requirements (DGRs) issued for the Project in March 2012, the EIS must also include the following in relation to GHG emissions:

- quantitative assessment of potential scope 1, 2, and 3 GHG emissions;
- qualitative assessment of potential impacts of these emissions on the environment; and
- an assessment of any reasonable and feasible measures to minimise GHG emissions and improve energy efficiency.

Table 2 below identifies where in this assessment the DGR's have been assessed.

Table 2 DGR's and assessment

DGR	Where Addressed
A quantitative assessment of potential scope 1, 2, and 3 GHG emissions	scope 1: Section 6 scope 2: Section 7 scope 3: Section 8
A qualitative assessment of potential impacts of these emissions on the environment	Section 11
An assessment of any reasonable and feasible measures to minimise GHG emissions and improve energy efficiency	Section 10

4.3 Centennial Climate Change Policy

Centennial recognises that climate change response is an important aspect of its business that presents both challenges and opportunities. Centennial believes GHG's can be reduced, mitigated and offset and also that coal will remain a significant energy source in a carbon constrained future and as such low emission technologies are essential. Consequently, Centennial is implementing a Climate Change strategy that combines strategic, operational, commercial and technical aspects of climate change.

The strategy includes a Climate Change Policy and development of a GHG Management System. Centennial is pursuing actions to:

- reduce GHG emissions through energy efficiency and fugitive emission abatement;
- accurately monitor fugitive emissions from underground coal mining operations; and
- effectively abate low concentration VAM through research and development with the Clean Coal Fund (NSW) in the further development and testing of Corky's VAM-RAB trial plant at the Mandalong Mine.

5.0 Mandalong Southern Extension Project Emissions Overview

5.1 Mine Plan

The Project is a proposed extension to the existing Mandalong Mine operations. The Project mining area is defined by the boundary of Exploration Licence EL6317 and is located immediately to the south of the existing mining lease (ML) for the Mandalong Mine. The proposed mining area covers approximately 4467 hectares in both the Lake Macquarie and Wyong Local Government Areas. Figure 2 illustrates the Project area as well as the Project ventilation fan locations.

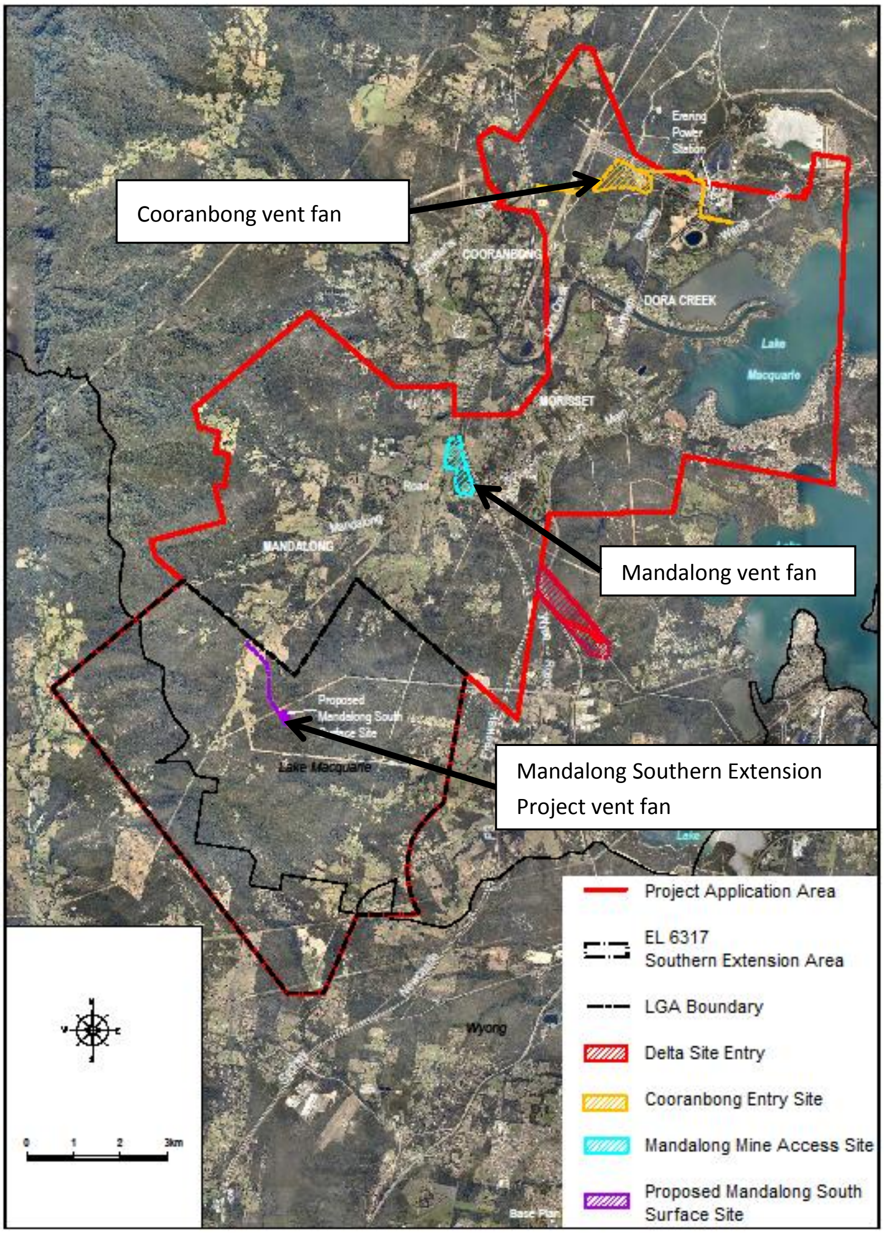

Figure 2 Project ventilation (vent) fan locations (Centennial, 2012)

5.2 GHG Inventory Boundaries, Activity Data and Emission Factors

Centennial is currently developing three new projects in the “Northern” group of mines. The boundaries between the three projects in terms of the GHG inventory are presented in Figure 1. The Project is only seeking approval to mine the coal, not the combustion of the coal to produce electricity. Despite this, this report has included an assessment of the scope 3 emissions for completeness.

5.2.1 Activity Data

The following assumptions for activity data and emission factors have been used for the emissions calculations. Table 3 presents the activity data and data sources predicted for the Project.

Table 3 Project activity data

Activity Data	Quantity	Units	Source
Maximum annual coal production	6.0	Mtpa	Centennial Mandalong (2012)
Project commences	2016	-	Centennial Mandalong (2012)
Project ceases	2041	-	Centennial Mandalong (2012)
Years of Project operation	25	years	Centennial Mandalong (2012)
In-situ gas content	6.0	$m^3\ t^{-1}$	Moreby (2011)
Pre-drainage gas CH_4 concentration	96	%	Cork (2012), Moreby(2011)
Pre-drainage gas CO_2 concentration	4	%	Cork (2012), Moreby(2011)
Long term average pre-drainage gas flow of CH_4	650	$L\ sec^{-1}$	Cork (2012), Moreby (2011)
Maximum pre-drainage gas flow of CH_4	800	$L\ sec^{-1}$	Cork (2012)
Maximum CH_4 flow from mine	2300	$L\ sec^{-1}$	Cork (2012), Moreby (2011)
Average flow rate of mine ventilation air (MVA)	280	$m^3\ sec^{-1}$	Cork (2012)
Maximum flow rate of mine ventilation air (MVA)	500	$m^3\ sec^{-1}$	Moreby (2011)
Average ventilation CH_4 concentration (VAM)	0.46	%	Moreby (2011), Cork (2012)

Average ventilation CO_2 concentration	0.019	%	Moreby (2011)
Cooranbong maximum ventilation flow rate	75	$m^3 sec^{-1}$	Moreby (2011)
Concentration of CH_4 in Cooranbong ventilation flow	0.09	%	Centennial Mandalong 2012 NGERS Reporting data
Concentration of CO_2 in Cooranbong ventilation flow	0.05	%	Centennial Mandalong 2012 NGERS Reporting data
Internal power needs (average demand)	13.9	MW_e	P. Cook, Pers comm (2012)
Annual average underground diesel usage	779	kL	P. Cook, Pers comm (2012)
Maximum annual underground diesel usage	984	kL	P. Cook, Pers comm (2012)

5.2.2 Materiality

A number of scope 1 emission sources are not included within the Project emissions calculations due to their contribution being less than 1% of total Project emissions. Emissions from SF_6 leakage, oils and grease (not combusted), LPG consumption and waste to landfill are immaterial (<1% of emissions) and are not utilised in emissions calculations in this Project.

5.2.3 Summary of Emissions Factors

The emission factors for the scope 1, 2 and 3 emissions are presented below and are sourced from the NGA factors (2012) published by the DCCEE.

Table 4 Gas engine methane combustion emission factors

Emission source	Energy Content (GJ/m^3)	Emission Factor (kg CO_2-e/GJ)			Source
		CO_2	CH_4	N_2O	
Coal seam methane captured for combustion	37.7×10^{-3}	51.6	5.0	0.03	NGA factors (2012) pg.13

Table 5 Methane flaring emission factors

Emission Source	Energy Content (GJ/m^3)	Emission Factor (kg CO_2-e/GJ)	Oxidation Factor	Source
Coal seam methane captured for combustion (flaring)	37.7×10^{-3}	47.117	0.98/0.995	NGER technical guidelines (2012) pg.182

Note:

Oxidation factor is comprised of two separate factors. 0.995 is the oxidation factor for natural gas and 0.98 is the combustion efficiency factor. The division of the two components gives the methane flaring oxidation factor.

Table 6 Diesel combustion emission factors

Emission Source	Energy Content (GJ/kL)	Emission Factor (kg CO_2-e/GJ)			Source
		CO_2	CH_4	N_2O	
Combustion of diesel oil for stationary energy purposes	38.6	69.2	0.1	0.2	NGA factors (2012) pg.16
Combustion of diesel oil for transport energy purposes (general transport)	38.6	69.2	0.2	0.5	NGA factors (2012) pg.18
Combustion of diesel oil for transport energy purposes (post-2004 vehicles)	38.6	69.2	0.01	0.6	NGA factors (2012) pg.18

Table 7 Electricity emission factors

Emission Source	State	Emission Factor (kg CO_2-e/kWh)	Source
Consumption of purchased electricity	NSW	0.88	NGA factors (2012) pg.20

Table 8 Product (coal) combustion emission factors

Emission Source	Energy Content (GJ/t)	Emission Factor (kg CO_2-e/GJ)			Source
		CO_2	CH_4	N_2O	
Bituminous coal	27	88.2	0.03	0.2	NGA factors (2012) pg.12

Table 9 Greenhouse gas GWPs

Gas	Global Warming Potential	Units	Source
Carbon dioxide (CO_2)	1	t CO_2-e per t CO_2	NGA factors (2012) pg.60
Methane (CH_4) pre-2017	21	t CO_2-e per t CH_4	NGA factors (2012) pg.60
Methane (CH_4) 2017 onwards	25*	t CO_2-e per t CH_4	DCCEE (2012)

*GWP for CH4 will increase to 25 from the year 2017 onwards (DCCEE, 2012)

Table 10 Greenhouse gas volume to mass conversion factors

Gas	Conversion Factor m^3 (STP) to t	Source
Carbon dioxide (CO_2)	1.861×10^{-3}	NGER (Measurement) Determination (2008) pg.108
Methane (CH_4)	6.784×10^{-4}	NGER (Measurement) Determination (2008) pg.108

NOTE:

All gas values are stated at Standard Temperature and Pressure (STP) of 288.15 K and 101.325 kPa (NGER (Measurement) Determination 2008, page 71).

6.0 Scope 1 Emissions

Scope 1 emissions refer to the "direct emissions" that occur as a result of the Project. This includes fugitive emissions from VAM and pre-drainage methane. This also includes use of diesel for stationary energy generation and transport.

The scope 1 emissions for the Project are:

- Fugitive emissions from drainage gas;
- Fugitive emissions from VAM; and
- Emissions from combustion of diesel.

6.1 Fugitive Gas Emissions

6.1.1 Methodology for Estimation of Fugitive Gas Emissions

Scope 1 fugitive emissions from the extraction of coal from underground mines have been determined using method 4, Division 3.2.2 Subdivision 3.2.2.2 section 3.6 of the NGER (Measurement) Determination 2008.

The calculation for determining the CO_2-e emissions from fugitive gas emissions is as follows:

$$E_{fug} = \left[\left((Q_T \times C_{CH4}) \times D_{CH4}\right) \times GWP_{CH4}\right] + \left[\left((Q_T \times C_{CO2}) \times D_{CO2}\right) \times GWP_{CO2}\right]$$

E_{fug} = Total fugitive gas emissions (t CO_2-e pa)

Q_T = Total gas/air flow (m^3 pa)

C_{CH4} = Methane concentration in air/gas flow (%)

D_{CH4} = Methane gas conversion factor (m^3 CH_4 to t CH_4)

C_{CO2} = Carbon dioxide concentration in air/gas flow (%)

D_{CO2} = Carbon dioxide gas conversion factor (m^3 CO_2 to t CO_2)

GWP_{CO2} = Carbon dioxide global warming potential (t CO_2-e / t CO_2)

GWP_{CH4} = Methane global warming potential (t CO_2-e / t CH_4)

6.1.2 Fugitive Emissions from Drainage Gas

The methane and carbon dioxide emissions that will be generated from the direct venting of drainage gas to the atmosphere have been quantified and are quantified in Table 11. The activity data presented in Table 3 has been used with the NGER (2012) methodology to determine the emissions. The data presented in Table 11 uses the maximum pre-drainage gas flow (800L sec^{-1}) to ensure the maximum possible GHG footprint is calculated and represented for the purposes of the EIS.

Table 11 Summary of drainage gas emissions

Emissions	Value	Units
Total maximum emissions from drainage gas	429,837	t CO_2-e pa

6.1.3 Fugitive Emissions from Mine Ventilation Air

The Project comprises three sites, the existing Mandalong Mine and Cooranbong sites, and the proposed southern extension surface site. All three sites will be connected via an underground ventilation network as illustrated in Figure 2. Ventilation fans are currently located at Cooranbong and Mandalong Mine and will be installed at the proposed southern surface site. The Cooranbong fan does not draw air from new mine workings and subsequently has a lower methane concentration and contribution to Project emissions.

The maximum predicted methane and carbon dioxide emissions that will be generated from the direct venting of mine ventilation air to the atmosphere have been quantified and are presented in Table 12, using the appropriate NGER (2012) methodology and the activity data presented in Table 3.

The average methane concentration (0.46%) and the maximum flow rate ($500m^3\ sec^{-1}$) are used in the calculation to ensure the maximum possible GHG footprint is calculated and represented for the purposes of the EIS.

Table 12 Ventilation air emission summary

Emissions	Value	Units
Maximum total CO_2-e emission from Mandalong and Mandalong Southern fans	1,235,732	t CO_2-e pa
Cooranbong total CO_2-e emission	38,303	t CO_2-e pa

6.2 Diesel Combustion Emissions

6.2.1 Methodology for Estimation of Emissions from Diesel Combustion

Scope 1 emissions from the combustion of diesel as a result of the Project have been determined using method 1, Division 2.4.2 section 2.41 of the NGER (Measurement) Determination 2008. In this section:

Stationary energy purposes means purposes for which fuel is combusted that do not involve transport energy purposes.

Transport energy purposes include purposes for which fuel is combusted that consist of any of the following:

(a) Transport by vehicles registered for road use;

(b) Rail transport;

(c) Marine navigation; and

(d) Air transport.

It should be noted that fuel combusted in transport vehicles not registered for road use is classified as fuel combusted for stationary energy purposes. Energy content and emission factors for various liquid fuels for stationary energy purposes can be found in the NGA factors (page. 16, 2012).

The calculation for determining emissions from diesel combustion is as follows;

$$E_D = \frac{(Q_D \times E_C) \times (Ef_{CH4} + Ef_{CO2} + Ef_{N2O})}{1000}$$

E_D = Total annual diesel emissions (t CO_2-e pa)

Q_D = Diesel quantity combusted (kL pa)

E_C = Diesel energy content (GJ/kL)

Ef_{CO2} = CO_2 diesel combustion emission factor (kg CO_2-e/GJ)

Ef_{CH4} = CH_4 diesel combustion emission factor (kg CO_2-e/GJ)

Ef_{N2O} = N_2O diesel combustion emission factor (kg CO_2-e/GJ)

Emissions from diesel combustion will vary depending on whether the combustion method is for stationary or transport related purposes.

6.2.2 Estimated Diesel Usage Emissions

Predicted annual Project diesel usage average is 779 kL with an estimated peak annual usage of 984 kL. Table 6 outlines the NGA (2012) energy content and emissions factors which are used to determine the annual emissions from diesel usage. It should be noted that emission factors for stationary energy purposes are used in all calculations as the vehicles used in underground transport are not registered for road use. The maximum emissions from diesel usage are presented in Table 13.

Table 13 Diesel usage emissions summary

Emissions	Value	Units
Maximum CO_2-e emission from diesel usage	2,640	t CO_2-e pa

7.0 Scope 2 Emissions

Scope 2 emissions refer to indirect emissions and generally relate to imported electricity. All imported electricity utilised by the Project is assumed to be derived from coal fired electricity generators.

7.1 Electricity Emissions

7.1.1 Methodology for Estimation of Emissions from Purchase of Electricity

Scope 2 emissions from the consumption of imported electricity have been determined using method 1, Chapter 7 section 7.2 of the NGER (Measurement) Determination 2008.

The calculation for determining emissions from electricity consumption is as follows;

$$E_{elec} = \frac{(Q_{elec} \times Ef_{elec})}{1000}$$

E_{elec} = Total electricity emissions (t CO_2-e pa)

Q_{elec} = Electricity consumed (kWh pa)

Ef_{elec} = NSW emission factor (kg CO_2-e/kWh)

7.1.2 Electricity Use Emissions

The total site electricity consumption is estimated to be 121,764 MWh per annum. This figure is calculated from a projected life-of-mine (LOM) electricity demand of 13.9 MW.

Table 14 Electricity usage and emissions

Emissions	Value	Units
Total electricity CO_2 emissions	107,152	t CO_2-e pa

8.0 Scope 3 Emissions

Scope 3 emissions are primarily derived from product combustion which forms the largest emissions, totalling over 300 Mt of CO_2-e for the life of Project. Other sources such as product transport and employees travel total less than 5% and can be considered immaterial in comparison.

Scope 3 emissions as a result of combustion of the product coal have been calculated using method 1, Division 2.2.2, section 2.4 of the NGER (Measurement) Determination 2008. Assuming a maximum Project production rate of 6 Mtpa of product coal the annual scope 3 emissions from the combustion of bituminous coal are 14,325,660 t CO_2-e pa.

The calculation for determining emissions from product coal combustion is as follows:

$$E_{PC} = \frac{(Q_{PC} \times E_C) \times (Ef_{CH4} + Ef_{CO2} + Ef_{N2O})}{1000}$$

E_{PC} = Total Bituminous product coal combustion emissions (t CO_2-e pa)

Q_{PC} = Bituminous product coal quantity combusted (kt pa)

E_C = Bituminous coal energy content (GJ/kt)

Ef_{CH4} = CH_4 bituminous coal combustion emission factor (kg CO_2-e/GJ)

Ef_{CO2} = CO_2 Bituminous coal combustion emission factor (kg CO_2-e/GJ)

Ef_{N2O} = N_2O bituminous coal combustion emission factor (kg CO_2-e/GJ)

9.0 Summary of Emissions

The annual and LOM emissions are displayed in Table 15. All calculations assume no abatement or avoidance of emissions.

Table 15 Summary of scope 1, 2 and 3 emissions for the Project

Scope	Emission Source	Maximum Emissions (t CO_2-e pa)	Maximum LOM Emissions (t CO_2-e pa)
1	Ventilation air emissions	1,274,035	31,615,745
1	Drainage gas	429,837	10,677,457
1	Diesel emissions	2,640	66,000
2	Electricity	107,152	2,678,800
3	Product combustion	14,325,660	358,141,500
Total Scope 1		1,706,512	42,359,200
Total Scope 1 and 2		1,813,664	45,038,008
Total Scope 3		14,325,660	358,141,500

This report has assessed the maximum scope 1 emissions predicted from the Project. In reality the total scope 1 emissions will likely be lower due to changes in production rates, methane concentrations within the coal and coal permeability. Figure 3 below shows the assessed and predicted scope 1 emissions from the Project area over the life of the Project as compared to the maximum emissions calculated above.

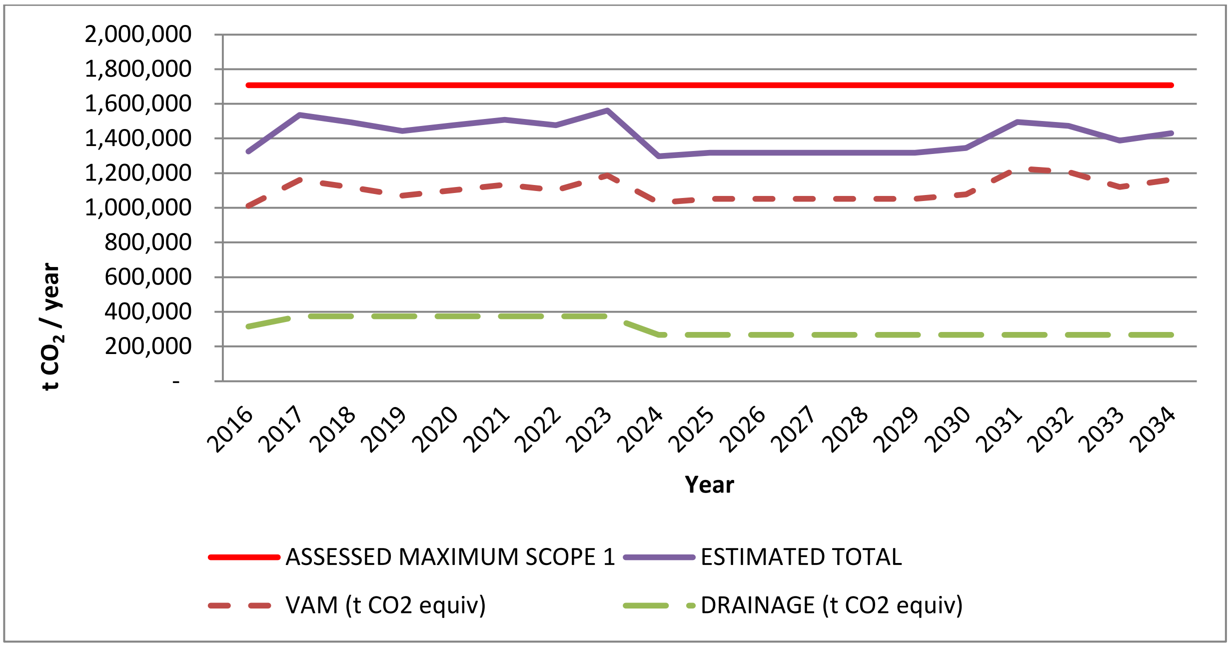

Figure 3 Assessed and predicted emissions for the Project (Centennial, 2012).

10.0 Abatement and Avoidance of Emissions

The Project has a number of options available for avoiding and off-setting scope 1 and 2 emissions. Table 16 displays the current Project options.

Table 16 Project abatement/avoidance options

Emission source	Abatement / Avoidance	Method of abatement or avoidance	Residual Emissions	Residual Emission actions
Drainage Gas	✓	Flaring and gas engine combustion (abatement)	CO_2 (combustion product)	Pay carbon tax or purchase certified carbon offsets
Ventilation Air	✓	VAM-RAB TRIAL (abatement)	CO_2 (combustion product)	
Diesel Combustion	--	--	--	
Electricity Consumption	✓	Electricity from gas engines (avoidance)	CO_2 (combustion product)	

10.1 Energy Efficiency Measures

Centennial is a partner to the NSW Government ESAP. This plan forms part of the broader Energy Administration Amendment (Water and Energy Savings) Act 2005 and gives the NSW Department of Energy, Utilities and Sustainability (DEUS) the responsibility to promote improvements in the energy efficiency of key businesses. Elements of ESAP also contribute to Federal programs such as EEO.

The ESAP program outlines best practice guidelines to assist commercial energy users in managing and optimising energy efficiency measures to reduce subsequent GHG emissions.

Centennial will be developing ESAPs for the Project and will be attempting to reduce energy use and avoid emissions at all times. The Project proposes the following energy efficiency measures:

- High voltage electrical power distribution – continuation of the high voltage (33kV) power line from the existing mine switchyard to the new services site. This reduces energy losses through the transmission of higher voltages over longer distances before the point of use.
- Power Factor Correction – use of power factor correction units at the new services site. This improves the efficiency of the electrical power used underground, hence reducing the overall power consumption.
- Compressed air distribution – removal of 6 km of compressed air line. This reduces energy losses through the frictional losses of compressed air in a pipeline together with the removal of leaks associated with that pipeline.
- Mine Dewatering – use of underground storage areas to settle solids out of mine waste water. This reduces energy losses through the ability to pump clean water out of the mine with the use of high efficiency positive displacement pumps.
- Delivery of bulk materials underground (concrete, stonedust, ballast) – Significant diesel fuel savings due to reduced travel distances and reduced seam to surface decents/accents through the 1 in 8 surface to seam drift.

10.2 Drainage Gas Abatement

It is planned that drainage gas will be piped back to the existing Mandalong Mine site for utilisation in gas engines (DA 97/800 Mod 4)

Due to the variable nature of the gas supply, the gas engine configuration has been designed to accept 77% (521 L sec^{-1} of drainage gas or 500 L sec^{-1} of methane) of the long term average volume (650 L sec^{-1}) of pre-drainage gas, providing 50 - 60% of Mandalong Mine's annual maximum electricity requirements (13.9 MW_e) (Cork, 2012). Note that whilst the total maximum pre-drainage gas GHG emissions have been calculated using the maximum pre-drainage gas volume (Section 6.1.2.), the long term average is a more suitable measure for estimating potential power generation through gas engines. The remaining 23% of the long term average pre-drainage gas (150 L sec^{-1} of methane) will be flared under the existing Mandalong Mine approval (DA 97/800 Mod 3).

Note that in terms of the maximum pre-drainage gas volumes (800 L sec^{-1}), only 64% of the pre-drainage gas would be used for gas engines (521 L sec^{-1} of pre-drainage gas or 500 L sec^{-1} of methane as above), whilst up to 36% will be flared. The volume used in the gas engines remains constant, whilst all excess volume above that required in gas engines will be flared.

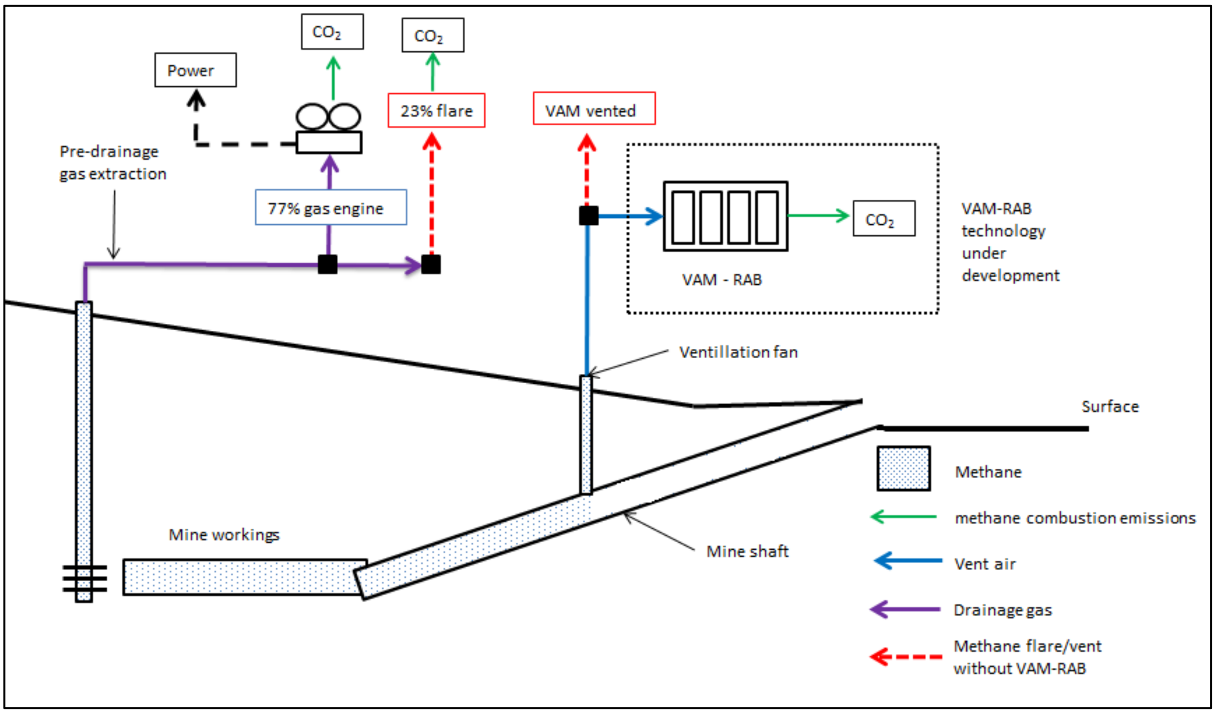

Figure 4 Abatement and residual emissions

The abatement of drainage gas through flares and engines at Mandalong Mine will reduce the scope 1 emissions by 377,658 t CO_2-e pa. This equates to the abatement of approximately 22% of total emissions through combustion of methane in gas engines and flaring. In addition the electricity generated will result in a reduction in scope 2 emissions of approximately 52%.

A summary of the drainage gas liability if it were vented directly to the atmosphere is presented in Table 17. Table 17 also presents the total annual abatement and avoidance of scope 2 emissions through the use of drainage gas in gas engines.

10.3 VAM Abatement

Ventilation Air Methane (VAM) abatement is a technically challenging process that has not yet been conducted with any reliable success in Australia or internationally. In addition to the technical challenges of abating low concentration methane (generally 0.3% to 1.0%), regulatory approval has not been granted for direct coupling of any device to a mine ventilation fan. The combination of a lack of regulatory approval (for which much needed research is being funded through the federally funded Coal Methane Abatement Technology Support Package (CMATSP) and the lack of proven technologies means that a commitment to VAM abatement cannot be made at this time for the Project.

However, Centennial, and in particular Mandalong Mine are acknowledged as leaders in attempting to develop safe and reliable VAM abatement technologies. Centennial, with the assistance of NSW Clean Coal Fund, are investing in a prototype of a technology (Corky's Ventilation Air Methane - Regenerative After Burner or "VAM-RAB") to investigate VAM abatement in a holistic manner. This includes efficacy of abatement, safe connection to the mine, reliability of operations and the environmental impact of the technology. The pilot VAM-RAB currently being constructed at the Mandalong Mine will treat 10 m^3 sec^{-1} of VAM. A calculation of potential VAM abatement has not been included in Table 17 as the technology is only under construction and will require further validation of reliability in particular, before claims of abatement are made. Note, however, that monitoring will occur and if abatement is proven it will reduce Mandalong Mine’s emissions.

Centennial is an industry leader in working on supporting the development of technology for industry and is committed to abating VAM if the technology is proven, safe and reliable. It is not possible to commit to large scale VAM abatement at this stage of the Project.

10.4 Summary of Avoidance and Emissions

Table 17 presents a summary of avoidance and abatement values.

Table 17 Abatement and residual emissions

Estimates Maximum Annual Emissions			Abatement and Avoidance	Residual	CEF Liability (Direct)
Scope	**Source**	**(t CO_2-e)**	**(t CO_2-e)**	**(t CO_2-e)**	**(t CO_2-e)**
1	VAM	1,274,035	-	1,274,035	1,274,035
1	Pre-Drainage Gas	429,837	377,658	52,178	52,178
1	Diesel	2,640	-	2,640	-*
2	Electricity	107,152	56,274	50,878	-*
TOTAL		**1,813,664**	**433,932 (24%)**	**1,379,731**	**1,326,213**

*Will be subject to a cost under the CEF through purchasing of diesel and electricity

10.5 GHG Offsets

As discussed in section 4.2.2, The Australian Government has developed the CEF Package to allow for the purchase of “carbon offsets” under schemes such as the CFI.

Centennial will be required to pay the relevant price per t CO_2-e depending on the year the liability is incurred, or purchase offsets. As discussed previously, after 2015, up to 50% of the emissions maybe offset using international “credits”. If credits are purchased, Centennial will purchase credits from accredited suppliers in approved markets.

11.0 Projected Climate Change Impacts

11.1 Emissions in National and State Context

11.1.1 Australian GHG Emissions

Australia's net greenhouse gas emissions totalled 560 Mt CO_2–e in 2009/10 (AGEIS), 2012). The energy sector accounts for approximately 75% of the total national emissions with energy generation through the combustion of fossil fuels accounting 55% of the national energy sector emissions. Fugitive emissions accounted for approximately 10% of energy sector emissions.

The contributions of the predicted emissions resulting from the Project are detailed in Table 18. As can be seen the emissions are a relatively small proportion of the Australian total emissions.

Table 18 Project emission contribution to national emission totals

	Percentage of Australian Energy Sector Total Emissions	Percentage of Australian Total Emissions
Maximum GHG emissions pa	0.32%	0.24%

11.1.2 NSW Emissions

NSW total emissions of 157.4 Mt CO_2–e accounts for approximately 28% of national GHG emissions. The energy sector contributes 119 Mt CO_2–e which is approximately 76% of the state emission total. Fugitive emissions account for approximately 17% of NSW total energy sector emission total.

Table 19 Project emission contribution in a total state emission context

	Percentage of NSW Energy Sector Total Emissions	Percentage of NSW Total Emissions
Maximum GHG emissions pa	1.11%	0.84%

The total predicted Project emissions make up a noticeable contribution to the NSW total emission inventory with slightly more than 1% contribution. NSW GHG inventory accounts for approximately 28% of the total national GHG account which reduces the overall Project GHG contributions to approximately 0.24% which is materially insignificant.

11.2 Conclusion

Australia's net GHG emissions account for approximately 1.47% (Garnaut, 2008) of the global greenhouse emission balance. The emissions represented by the Project account for approximately 0.24% of total Australian GHG production. As such, the relatively small amount of GHG emissions generated by the Project will have a negligible effect on global climate change.

12.0 Appendix 1: Emissions Calculation Notes

	Flow ($L\ sec^{-1}$)	Composition
Maximum total drainage gas flow	833	800 $L\ sec^{-1}$ methane (96%) 33 $L\ sec^{-1}$ carbon dioxide (4%)
Long term average total drainage gas flow	677	650 $L\ sec^{-1}$ methane (96%) 27 $L\ sec^{-1}$ carbon dioxide (4%)

The gas engine configuration is designed on the long term average methane gas flow of 650 L sec^{-1}. It is proposed that 77% (500 L sec^{-1}) of this methane flow will be combusted in the gas engines. The remaining 23% of methane flow will be combusted by flaring.

The maximum drainage gas flow is 833 L sec^{-1} which comprises of an additional 150 L sec^{-1} methane above the long term average of 650 L sec^{-1} (800 – 650 = 150). This additional methane will be combusted by flares. Total methane flared is 300 L sec^{-1} (150 + 150 = 300).

A maximum potential total of 833 L sec^{-1} drainage gas will be processed with 500 L sec^{-1} methane (77%) being combusted in gas engines and 300 L sec^{-1} combusted by flaring. The maximum total of 60 L sec^{-1} carbon dioxide (27 + 33) contributes to the total residual drainage gas emissions after abatement.

The abatement calculation is as follows;

NOTE 1: Figures rounded to whole numbers to allow simple calculation and as such, totals may vary to figures reported in main body of report.

NOTE 2: Example calculations use the GWP of 25 for CH_4, as this is the applicable GWP from 2017 onwards which account for 24 years out of the 25 year LOM.

12.1 Drainage Gas Emissions - No Abatement

- **Methane**

$$E_{DG} = (800\ (L\ sec^{-1}) \div 1000) \times 3600 \times 24 \times 365 = 25{,}228{,}800 m^3 \text{ pa}$$
$$E_{DG} = 25{,}228{,}800\ (m^3 \text{ pa}) \times 0.0006784\ (t\ m^{-3}) = 17{,}115\ t\ CH_4\ pa$$
$$E_{DG} = 17{,}115 (t\ pa) \times 25 = \mathbf{427{,}880}\ t\ CO_2 - e\ pa$$

- **Carbon dioxide**

$$E_{DG} = (33\ (L\ sec^{-1}) \div 1000) \times 3600 \times 24 \times 365 = 1{,}040{,}688\ m^3 \text{ pa}$$
$$E_{DG} = 1{,}040{,}688\ (m^3 \text{ pa}) \times 0.001861\ (t\ m^{-3}) = \mathbf{1{,}937}\ t\ CO_2\ pa$$
$$E_{DG} = 1{,}937\ (t\ pa) \times 1 = \mathbf{1{,}937}\ t\ CO_2 - e\ pa$$

$\therefore Total\ unabated\ emissions = 427{,}880 + 1{,}937 = \mathbf{429{,}817}\ t\ CO_2 - e\ pa$

NOTE 3: The carbon dioxide component of drainage gas (1,937 t CO_2-e) is emitted even when drainage gas abatement options are employed. Hence it is explicitly added to each of the calculations below and referenced as DGCO$_2$.

Abatement emissions

Drainage gas - abate 77% via gas engines and 23% via flaring

- **Emissions – Gas Engines**

$$E_{GE} = [(650 \times 0.77)\ (\ L\ sec^{-1}) \div 1000)] \times 3600 \times 24 \times 365$$

$$= 15{,}783{,}768\ m^3 \text{ pa}$$

$$E_{GE} = [15{,}783{,}768\ (m^3 \text{ pa}) \times 0.0377(GJ\ m^{-3})] \times (51.6 + 5 + 0.03)$$

$$E_{GE} = 33{,}697{,}571\ kg\ CO_2 - e\ pa + \text{ 77\% of DGCO}_2 \text{ @ 1,491 t CO}_2 - \text{e}$$

$$E_{GE} = \mathbf{35{,}188}\ t\ CO_2 - e\ pa$$

- **Emissions – Flaring**

$$E_{FL} = [(300\ (\ L\ sec^{-1}) \div 1000)] \times 3600 \times 24 \times 365 = 9{,}460{,}800\ m^3 \text{ pa}$$

$$E_{FL} = [9{,}460{,}800\ (m^3 \text{ pa}) \times 0.0377(GJ\ m^{-3})] \times 47.117(kgCO_2 - e\ GJ^{-1}) \times \frac{0.98}{0.995}$$

$$E_{FL} = 16{,}551{,}975\ kg\ CO_2 - e\ pa\ +\ \text{23\% of DGCO}_2 \text{ @ 456 t CO}_2 - \text{e}$$

$$E_{FL} = \mathbf{17{,}008}\ t\ CO_2 - e\ pa$$

Total residual emissions post abatement

$$E_{RES} = E_{GE} + E_{FL}$$

$$E_{RES} = 35{,}188 + 17{,}008 = \mathbf{52{,}196}\ t\ CO_2 - e\ pa$$

Total abatement benefit

$$Emissions\ abatement\ benefit = total\ unabated\ emissions - residual\ emissions$$

$$E_{AB} = E_{DG} - E_{RES}$$

$$E_{AB} = 429{,}817 - 52{,}196$$

$$E_{AB} = \mathbf{377{,}621}\ t\ CO_2\ - e\ pa$$

NOTE: Calculated figures above vary to those presented in Table 17 due to rounding to enable simplistic calculation.

12.2 Diesel Fuel Consumption Emissions

$$E_D = \frac{(Q_D + E_C) \times (Ef_{CH4} + Ef_{CO2} + Ef_{N2O})}{1000}$$

$E_D = Total\ annual\ emissions\ (t\ CO_2 - e\ pa)$	2640
$Q_D = Diesel\ quantity\ combusted\ per\ annum\ (kL\ pa)$	984.014
$E_C = Diesel\ energy\ content\ (GJ/kL)$	38.6
$Ef_{CO2} = CO_2\ diesel\ combustion\ emission\ factor\ (kg\ CO_2 - e/GJ)$	69.2
$Ef_{CH4} = CH_4 diesel\ combustion\ emission\ factor\ (kg\ CO_2 - e/GJ)$	0.1
$Ef_{N2O} = N_2O\ diesel\ combustion\ emission\ factor\ (kg\ CO_2 - e/GJ)$	0.2

$$E_D = \frac{(984.014 \times 38.6) \times (69.2 + 0.1 + 0.2)}{1000}$$

$$E_D = \mathbf{2,640}\ t\ CO_2 - e\ pa$$

12.3 Fugitive VAM Emissions

$$E_{fug} = \left(\left((Q_T \times C_{CH4}) \times D_{CH4}\right) \times GWP_{CH4}\right) + \left(\left((Q_T \times C_{CO2}) \times D_{CO2}\right) \times GWP_{CO2}\right)$$

$E_{fug} = Total\ fugitive\ gas\ emissions\ (t\ CO_2 - e\ pa)$	1,071,434
$Q_T = Total\ flow\ gas/air\ \ (m^3pa)$ **Mandalong**	1.5768×10^{10}
$Q_T = Total\ flow\ gas/air\ \ (m^3pa)$ **Cooranbong**	2.3652×10^{9}
$C_{CH4} = Methane\ concentration\ in\ \ air/gas\ flow$ (%) **Mandalong**	0.46
$C_{CH4} = Methane\ concentration\ in\ \ air/gas\ flow$ (%) **Cooranbong**	0.09
$D_{CH4} = Methane\ gas\ conversion\ factor\ (m^3CH_4 to\ t\ CH_4)$	0.0006784
$C_{CO2} = Carbon\ dioxide\ concentration\ in\ \ air/gas\ flow$ (%) **Mandalong**	0.019
$C_{CO2} = Carbon\ dioxide\ concentration\ in\ \ air/gas\ flow$ (%) **Cooranbong**	0.05
$D_{CO2} = Carbon\ dioxide\ gas\ conversion\ factor\ (m^3CO_2 to\ t\ CO_2)$	0.001861
$GWP_{CO2} = Carbon\ dioxide\ global\ warming\ potential\ (t\ CO_2 - e/t\ CO_2)$	1
$GWP_{CH4} = Methane\ global\ warming\ potential\ (t\ CO_2 - e/t\ CH_4)$	25*

*Refer to ***NOTE 2*** on pg. 38 of this report

Mandalong

$$E_{fug} = \left(\left((1.5768 \times 10^{10} \times 0.0046) \times 25\right) \times 0.0006784\right)$$
$$+ \left(\left((1.5768 \times 10^{10} \times 0.00019) \times 1\right) \times 0.001861\right)$$

$$E_{fug} = 1{,}230{,}156 + 5{,}575$$

$$E_{fug} = \mathbf{1,235,731}\ t\ CO_2 -\ e\ pa$$

Cooranbong

$$E_{fug} = \left(\left((2.3652 \times 10^{9} \times 0.0009) \times 0.0006784\right) \times 25\right)$$
$$+ \left(\left((2.3652 \times 10^{9} \times 0.0005) \times 1\right) \times 0.001861\right)$$

$$E_{fug} = 36{,}102 + 2{,}201$$

$$E_{fug} = \mathbf{38,303}\ t\ CO_2 -\ e\ pa$$

Total

$$E_{fug} = 1{,}235{,}731 + 38{,}303$$

$$E_{fug} = \mathbf{1{,}274{,}034}\ t\ CO_2 - \ e\ pa$$

12.4 Electricity Consumption Emissions

$$E_{elec} = \frac{Q_{elec} \times Ef_{elec}}{1000}$$

$E_{elec} = Total\ annual\ electricity\ emissions\ (t\ CO_2 - e\ pa)$	107,152
$Q_{elec} = Electricity\ consumed\ per\ annum\ (kWh\ pa)$	121,764,000
$Ef_{elec} = NSW\ emission\ factor\ (kg\ CO_2 - e/kWh)$	0.88

$$E_{elec} = \frac{121{,}764{,}000 \times 0.88}{1000}$$

$$E_{elec} = \mathbf{107{,}152}\ t\ CO_2 - e\ pa$$

12.5 Product Coal Combustion Emissions (Bituminous)

$$E_{PC} = \frac{(Q_{PC} \times E_C) \times (Ef_{CH4} + Ef_{CO2} + Ef_{N2O})}{1000}$$

$E_{PC} = Total\ product\ coal\ combsution\ emissions\ (t\ CO_2 - e\ pa)$	14,325,660
$Q_{PC} = Product\ coal\ quantity\ combusted\ per\ annum\ (t\ pa)$	6,000,000
$E_C = Coal\ energy\ content\ (GJ/t)$	27

$Ef_{CO2} = CO_2\ coal\ combustion\ emission\ factor\ (kg\ CO_2 - e/GJ)$	88.2
$Ef_{CH4} = CH_4 coal\ combustion\ emission\ factor\ (kg\ CO_2 - e/GJ)$	0.03
$Ef_{N2O} = N_2O\ coal\ combustion\ emission\ factor\ (kg\ CO_2 - e/GJ)$	0.2

$$E_{PC} = \frac{(6{,}000{,}000 \times 27) \times (88.2 + 0.03 + 0.2)}{1000}$$

$$E_{PC} = \mathbf{14{,}325{,}660}\ t\ CO_2 - e\ pa$$

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