Annex C

C. Greenhouse Gas Assessment

Appin Colliery Area 7

Goaf Gas Drainage Project

Greenhouse Gas Assessment

Project Number 109033-02-Report 002 Rev 1

Prepared for BHP Billiton Illawarra Coal

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Executive Summary

BHP Billiton Illawarra Coal (BHPBIC) has Subsidence Management Plan (SMP) approval to mine Longwalls 701 to 704 at Appin Colliery Area 7, within the Southern Coalfield of NSW. BHPBIC has completed mining Longwall 702 and mining of Longwall 703 is expected to commence in November 2009.

Appin Colliery mines coal from the Bulli Seam, which contains relatively high methane gas (CH_4) content. Therefore, measures to drain the gas from the coal seam and from the goaf areas of the mine are used to minimise the quantity of gas that reports to the Mine Ventilation Air (MVA). High concentrations of methane in the MVA can cause significant underground safety risks, delays in development and longwall mining, and direct emissions of methane to the atmosphere via the upcast ventilation shafts.

BHPBIC propose to drain goaf gas from Longwalls 703 to 704 within Appin Area 7 by:

1. Implementing a procedure to safely drain the goaf gas;
2. Safely capturing, reticulating and managing the goaf gas;
3. Minimising impacts on cultural heritage, and the natural and urban environment; and
4. Minimising Greenhouse Gas (GHG) emissions.

Extracted goaf gas will be piped to the Energy Developments Limited (EDL) Power Station at Appin Colliery for electricity generation, with a small amount of venting to the atmosphere in the event of plant breakdown or operational issues. If significant operational issues arise causing ongoing venting, Illawarra Coal will consider the implementation of on-site flaring as a contingency measure. The proposed project will minimise GHG emissions through the conversion of methane gas to carbon dioxide, which has a lower Global Warming Potential (GWP). The project will also offset emissions associated with coal fired power generation through the use of the extracted goaf gas for energy generation at EDL.

Cardno Forbes Rigby (Cardno) was engaged by BHPBIC to prepare a GHG Assessment (GGA) for the proposed project. The scope of this GGA has been defined by the Director Generals Requirements (DGRs) for the project, which require a full greenhouse gas assessment, including an assessment of:

- The amounts of methane likely to be either a) vented; or, b) flared;
- The feasible alternatives for the utilisation of the methane produced by the project;
- A quantitative analysis of the greenhouse emissions associated with the project; and
- A qualitative assessment of the impacts of these emissions on the environment.

The methodology and approach used in this assessment aims to address the above listed requirements.

All greenhouse gas emission calculations were undertaken in accord with the methodology outlined in the *National Greenhouse Accounts (NGA) Factors* (2008) and industry best practice. To evaluate the change in emissions due to the project, all emission sources were categorised into either Scope 1, 2 or 3 type emissions, in accord with the NGA Factors (2008). The various Scope emission sources for the project are summarised in the following table.

We note that no Scope 2 emissions (electricity consumption) are associated with the proposed project as it is anticipated that all energy requirements will be supplied by onsite diesel generators, which have been included in Scope 1 emissions.

GHG Emission Sources

Scope 1 Emissions	Scope 2 Emissions	Scope 3 Emissions
• Diesel combustion during construction and installation works; • Drilling of MRD boreholes and vertical wells; • Diesel combustion during transportation of plant and materials; • Fuel combustion during employee travel associated with construction / installation works; • Diesel combustion resulting from ongoing power supply to the goaf extraction plant and flaring units; • Production of CO_2 and N_2O during onsite flaring of the extracted gas; and • Emission of CO_2 and CH_4 during from onsite venting of extracted gas directly to the atmosphere.	N/A	• Production of CO_2 and N_2O during combustion of extracted gas at EDL's Appin Colliery Power Station; and • Indirect extraction emissions associated with all Scope 1 fuel combustion emissions listed in column 1 (these emissions occur during the extraction and transportation of fuels used for energy).

This GGA quantifies the likely reduction in GHG emissions associated with the project by estimating baseline emissions (defined as those that would occur without the project) and post-project emissions (defined as those that would occur with the project), and comparing the two to determine the likely net reduction in GHG emissions that will result from the project being approved and implemented.

Baseline emissions were taken as the total emissions that would occur from Appin Mine due to the mining of Longwalls 703 to 704 without any utilisation of extracted goaf gas. Baseline emissions were estimated using the NGA Factors (2008) methodology for estimating fugitive emissions from underground coal mines (gassy mines), which is the industry accepted and agency preferred method for estimating fugitive mining emissions. This methodology accounts for release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata (NGA, 2008).

Post-project emissions were taken as the total emissions that would occur from Appin Mine if the proposed goaf gas drainage project was implemented, factoring the likely amounts of goaf gas to be used for energy generation, flared onsite, or vented directly to the atmosphere. Post-project emissions also included emissions that would occur during setup and installation works, and fuel consumption during operation of the extraction plants and flaring units.

BHPBIC are in consultation with Integral Energy and propose to connect the preferred extraction plant located on the property described as Lot 2 DP576136, to the existing 11kVA mains located on the adjacent property described as Lot 1 DP576136. This GGA has taken a conservative approach in assessing GHG emissions associated with proposed project and has therefore assumed the worst case scenario in that the preferred extraction plant and contingency extraction plant (if utilised) will be powered by a diesel generator.

Should the preferred extraction plant be able to be powered by electricity and not diesel, the actual GHG emissions associated with the operation of the extraction plant will be significantly lower due to this; however, the GHG emissions determined by this GGA has assumed the use of diesel fuel for operation of the extraction plant/s.

This GGA determined that the project will significantly reduce and offset GHG emissions by converting methane to CO_2, and generating electricity at the EDL Power Station. Methane is a GHG with a GWP of 21, which means that 1 tonne of methane gas emissions is equivalent to 21 tonnes of Carbon Dioxide (CO_2) emissions. Therefore, any conversion of methane to CO_2 by combustion will result in a reduction in Carbon Dioxide equivalent (CO_{2-e}) GHG emissions. The goaf gas drainage project will reduce GHG emissions in this way. The estimated baseline, post-project, and net reduction in emissions likely to occur as a result of the project is provided in the following table.

Net Reduction in Emissions at Appin Mine Resulting from the Project

Operation	Total Emissions at Appin Mine (kt CO_2-e over the life of the project)	Equivalent Annual Emission (kt CO_2-e/yr)
Baseline Fugitive Emissions due to Mining of Longwalls 703 to 704	2028	1193
Post-Project Emissions	1694	996
Net Reduction in Emissions due to Goaf Gas Drainage Project	334	197

This assessment shows that the Project will result in a net reduction in GHG emissions of approximately 334,000 t CO_2-e (i.e. an annual equivalent of approximately 197,000 t CO_2-e based on a project timeframe of 1.7 years). In addition to this direct net reduction in emissions, the project will also offset emissions associated with coal fired power generation by utilising extracted methane gas for energy generation at the EDL Power Station. It is estimated that each MWh of electricity generated using extracted goaf gas will represent an emission offset of 0.89 t CO_2-e, and the total emission offset throughout the life of the goaf gas extraction project will be in the order of 44,000 – 89,000 t CO_2-e.

The DGRs issued for the project requested identification of feasible alternatives for the utilisation of goaf gas. The project proposes to convey as much of the extracted goaf gas as possible to the EDL Power Station at Appin Colliery for energy generation. If operational issues cause significant venting of the goaf gas then Illawarra Coal will consider the installation and operation of an on-site flare to abate GHG emissions.

Notwithstanding the above, the alternatives for the utilisation of goaf gas determined by this assessment include increased flare capacity, installation of VAMP plants at other upcast ventilation shaft sites, and an increased power generation capacity at the existing EDL Power Stations. This assessment concludes that none of these alternatives are feasible or reasonable in this instance and the project represents the most environmentally and economically feasible alternative for the management of the extracted goaf gas.

This GGA recommends that the goaf gas extraction project aim to maximise the amount of gas utilised in the following order of priority:

1. Reuse for energy generation at the EDL Power Station; and
2. Onsite flaring if ongoing venting occurs; or
3. Venting to atmosphere.

It is recommended that BHPBIC aim to minimise the amount of goaf gas vented directly to the atmosphere, and the consumption of diesel and petrol fuel wherever possible during the construction and operation phase of the project.

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1 Introduction

1.1 Purpose of this Report

BHP Billiton Illawarra Coal Pty. Ltd. (BHPBIC) is seeking Part 3A approval for surface works and activities related to the drainage of goaf gas from coal mining at Appin Area 7 Longwalls 703 to 704. BHPBIC has Subsidence Management Plan (SMP) approval to mine Longwalls 701 to 704 granted by the Department of Primary Industries in November 2006. These Longwalls will extract coal from the Bulli Coal Seam at an approximate depth of 500m within an area approximately 6km north-west of the township of Appin in NSW.

BHPBIC have commissioned Cardno Forbes Rigby (Cardno) to prepare a Greenhouse Gas Assessment (GGA) for the proposed goaf gas drainage project. This GGA has been prepared in accord with the Director-General Requirements (DGRs) for the project, which were issued to BHPBIC by the NSW Department of Planning (DoP) on the 2 February 2009.

1.2 Scope of Study

The scope of this GGA has been defined by the DGRs for the project, which require a full greenhouse gas assessment, including an assessment of:

- The amounts of methane likely to be either a) vented; or, b) flared;
- The feasible alternatives for the utilisation of the methane produced by the project;
- A quantitative analysis of the greenhouse emissions associated with the project; and
- A qualitative assessment of the impacts of these emissions on the environment.

The methodology and approach used in this assessment is aimed at addressing the above listed requirements.

1.3 Existing Operations and Project Context

BHPBIC has SMP approval to mine Longwalls 701 to 704 in Appin Mine's Area 7 and is now seeking SMP approval to mine Longwalls 705 to 710 to the north of the abovementioned longwalls within this mining domain.

The mining of coal within the coal seams underground releases gases, which have been trapped within the coal seam pores by the chemical process of adsorption and/or absorption, produced by the coalification process. These gases consist primarily of methane which is a Greenhouse Gas that has a Global Warming Potential (GWP) of 21.

BHPBIC use in-seam drilling to drain methane contained within the Bulli Coal Seam prior to mining. Seam gas from the strata underlying the longwall is drained by cross measure boreholes. The in-seam and cross measure gas drainage produces high purity methane gas. These measures are known as pre-mine drainage. Post mining drainage is used to minimise the gas content within in the Mine Ventilation Air (MVA) and this is known as goaf gas drainage i.e. the gas is removed from the goaf area within the mine after the coal has been extracted.

If unmanaged, goaf gas can enter the mine ventilation system and cause safety and operational issues, including the risk of an uncontrolled underground explosion. The MVA is emitted to the atmosphere at upcast ventilation shafts. MVA from Appin Mine has a methane concentration in the order of 0.8 %. In order to limit the potential for gas build up in the mine ventilation system and mitigate safety and operational risks, and also to reduce GHG emissions, BHPBIC propose a gas extraction system to draw the goaf gas to the surface, and a gas utilisation system to reduce GHG emissions. BHPBIC require surface equipment to drain this goaf gas. This equipment constitutes development of land that is ancillary to coal mining thereby requires development approval under the Environmental Planning & Assessment Act 1979.

1.4 Report Outline

This layout of this report is as follows:

Section 1 Introduction.

Section 2 Description of the Project, which provides a description of the various construction and installation works, as well as the operation of the project including the likely amounts of methane that will be extracted.

Section 3 Greenhouse Gas Assessment, which describes the methodology and source data used in the assessment, and presents the results of the study.

Section 4 Impact Assessment, which provides a qualitative assessment of the impacts of greenhouse gas emissions on the environment and a description of abatement measures employed by IC to minimise greenhouse gas emissions.

Section 5 Assessment of Feasible Alternatives for Goaf Gas Utilisation.

Section 6 Conclusions and Recommendations.

2 Description of the Project

2.1 Project Overview

This report forms the GGA for activities directly related to the proposed goaf gas drainage project for Appin Colliery Area 7 Longwalls 703 to 704.

The objectives of the goaf gas drainage project are to:

1. Implement a procedure to safely drain the goaf gas;
2. Safely capture, reticulate and manage the goaf gas;
3. Minimise impacts on cultural heritage and the natural and urban environment; and
4. Minimise Greenhouse Gas (GHG) emissions.

Every coal mine with high coal seam gas concentrations has to put in place procedures for controlling the gas concentrations in their ventilation systems. BHPBIC propose to drain gas from the goaf areas of Longwalls 703 and 704 by drilling vertical and steered boreholes, between the extracted coal seam and the surface ground level. The goaf gas will be drawn up the boreholes by extraction plants located on the surface to ensure underground gas concentrations remain well below 1.25 % in the MVA.

The extraction plants use a vacuum pump to draw the goaf gas to, and up, the wells thus minimising gas in the goaf from entering the mine ventilation system. The proposed extraction plants will be in a centralised location so that gas may be drawn from multiple wells/boreholes that are connected by a surface pipeline reticulation system.

BHPBIC has obtained written approval from the landowners prior to the location and implementation of the extraction plants, wellheads and pipelines. These facilities are temporary in nature and only require a small area that is located in an open paddock to avoid or minimise environmental impacts. The surface facilities will be fenced to control access to these sites.

One primary and one contingency extraction plant are proposed to be used for the goaf gas drainage of Longwalls 703 to 704 (refer **Annex A** for plans showing location of extraction plants and associated surface facilities). The extraction plants will be mobile, semi-trailer mounted and powered by a diesel generator.

2.2 Project Timeframe

Mining of Longwalls 703 to 704 is scheduled to commence in November 2009 and it is estimated to be complete by approximately August 2011. This estimate is based on a mining progression rate of 50 m per week, over the total approximate length of both longwalls of 4239 m, with allowance for a four week period between longwalls to relocate mining equipment. The anticipated schedule of mining is provided in **Table 2.1**.

Table 2.1 – Anticipated Project Timeframe

Activity / Operation	Approximate Start Date	Approximate Finish Date
Installation of goaf gas drainage infrastructure	Date of Approval	November 2009
Mining of Longwall 703	November 2009	August 2010
Relocate underground mining equipment	August 2010	September 2010
Mining of Longwall 704	September 2010	July 2011

From the above table it is assumed that the duration of the goaf gas drainage project is likely to be 1.7 years or 89 weeks.

2.3 Installation and Operation of Goaf Gas Drainage System

2.3.1 Borehole and Surface Pipelines

BHPBIC will implement two types of boreholes for this project:

1. Medium Radius Drilled (MRD) wells – a 250 mm borehole, which starts vertically from the surface and is steered to near horizontal for some distance above the goaf (refer **Figure 2.1**). The MRD hole may have a number of branches to improve gas flow; and
2. Vertical wells – a 250 mm borehole drilled vertically from surface level to the goaf (refer **Figure 2.1**).

The location and type of boreholes used for the proposed goaf gas drainage of Longwalls 703 to 704 is presented in **Annex A**.

The vertical wells are drilled from the surface using a mobile drilling rig to a depth of approximately 10 m above the Bulli Coal Seam roof, approximately 500 m underground. A temporary fence would surround the rig and associated equipment during drilling. Associated equipment includes a rod trailer, ponds or sumps, compressors, storage shed and portable toilet. The compound would be approximately 30 m x 40 m in area.

Medium radius drilled (MRD) wells have emerged over the past two years as a viable addition or alternative to underground based in-seam drilling in coal mines and vertical well hydro-fracture for coal seam methane exploitation. The basic MRD well consists of an inclined, medium radius borehole collared at the surface to tangentially extend horizontally above the target coal seam at a approximate height of 50 m (refer **Figure 2.1 and Annex A**).

On the surface, the two borehole types appear identical. Each borehole has a well head, which is where the borehole breaks the ground surface (refer to **Figure 2.2**), and is attached to the surface pipeline reticulation system. The following equipment is proposed for installation at each wellhead:

- Shut off valve;
- Non–return valve;
- Flame trap;
- Gas monitoring fittings;
- Flow monitoring fittings;
- Polyethylene piping to carry the gas away to the extraction plants; and
- Fencing to prevent unauthorised access.

2.3.2 Extraction Plant

The proposed extraction plant will be located in a centralised location remote from the individual well heads. The preferred location for the extraction plant is on the western side of the Hume Highway on the property described as Lot 2 DP 576136, with an underbore connection beneath the Hume Highway and Main Southern Rail Line connecting the gas drainage network for Longwall 703 to that of Longwall 704 (refer **Annex A**). This would allow the use of only one extraction plant and the extracted goaf gas from Longwalls 703 and 704 to be conveyed to the Energy Developments Limited (EDL) Power Station at Appin Colliery via a downhole on Lot 1 DP 576136 to the existing underground gas drainage pipe range. However, if approval is not granted to underbore the Hume Highway and Main Southern Rail Line, a second back up or contingency extraction plant location on the eastern side of the Hume Highway would be required, and would be located on the property described as Lot 6 DP 250231 if required (refer **Annex A**).

BHPBIC are in consultation with Integral Energy and propose to connect the preferred extraction plant located on the property described as Lot 2 DP576136, to the existing 11kVA mains located on the adjacent property described as Lot 1 DP576136. This GGA has taken a conservative approach in assessing GHG emissions associated with proposed project and has therefore assumed the worst case scenario in that the preferred extraction plant and contingency extraction plant (if utilised) will be powered by a diesel generator.

Should the preferred extraction plant be able to be powered by electricity and not diesel, the actual GHG emissions associated with the operation of the extraction plant will be significantly lower due to this; however, the GHG emissions determined by this GGA has assumed the use of diesel fuel for operation of the extraction plant/s.

The extraction plant will draw gas from multiple wells that are connected by a surface pipeline reticulation system. A separate diesel powered electricity generator is necessary to power the plant and provides approximately 175kVA of power. Experience indicates that this will require filling once a week by a mobile diesel tanker.

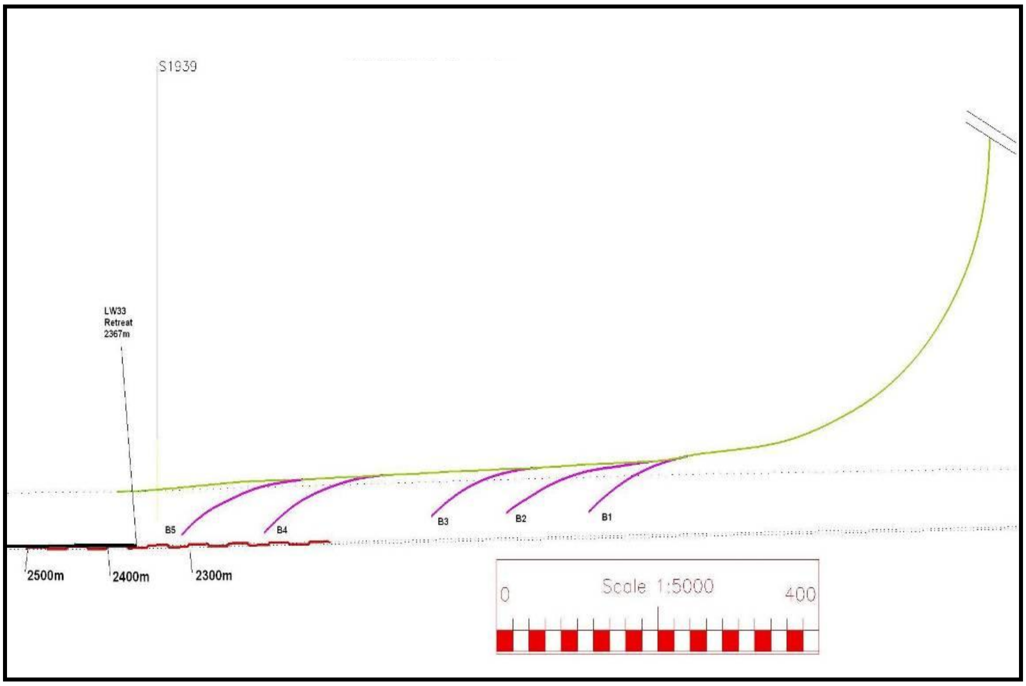

Figure 2.1 – Section Showing Vertical Well and MRD Borehole and Branches

Figure 2.2 – Typical Wellhead

BHPBIC has obtained written approval from all the landowners for the implementation of the extraction plant, well heads and surface pipelines proposed for their land. The proposed infrastructure is temporary in nature and only requires a small area that will be located in an open paddock and sited to avoid or minimise environmental impacts. All surface impacts will be rehabilitated to the pre-project land use at the completion of the project or to landowner's specific requirements.

The facility does not require permanent staff because monitoring and safety systems allow remote operation of the extraction plant via radio communications.

Well flows are variable but BHPBIC expect each well would produce up to 800 L/s of goaf gas for a period of approximately 4 to 12 weeks. Expected average flow over the life of a well would be around 400 L/s. The nominal capacity of the extraction plant is 800 L/s.

Figure 2.3 shows a drawing of a typical goaf gas extraction plant layout, which consists of:

- Mobile goaf gas extraction plant
- Discharge gas pipe work to discharge point;
- Remote vent stack; and
- Flare units.

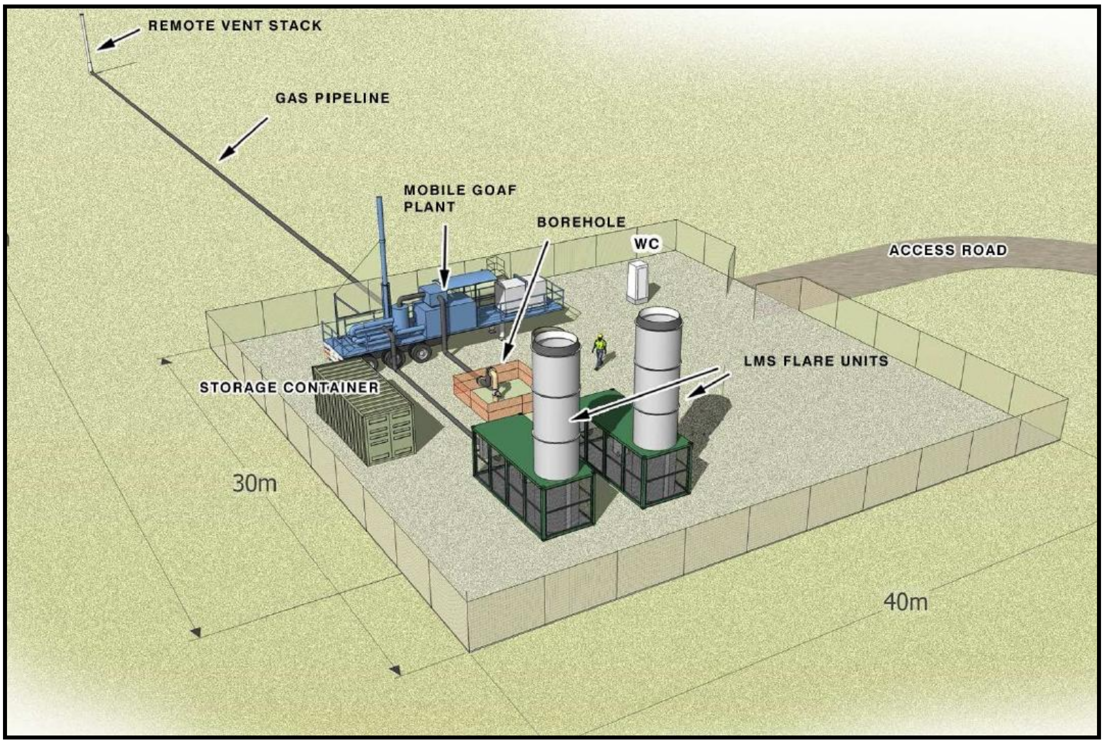

Figure 2.3 – Typical Extraction Plant Layout (*Source: Maurice Hayler & Associates Architects)*

2.3.3 Location of Drainage Infrastructure

The proposed location of the drainage infrastructure and extraction plants is shown on the concept drainage layout for Appin Area 7 Longwalls 703 to 704, which is provided in **Annex A**.

The wellheads are located at the top of the boreholes and the proposed surface reticulation pipeline will be located in a trench just below the surface ground level where possible. The proposed pipelines are located on private property, and BHPBIC have obtained written approval from relevant property owners for this infrastructure.

The location of wellheads responds to the longwall design and the goaf areas. As it is vital for the borehole to access the goaf area there is only limited opportunity to alter the location of the wells. Selection for the location of the proposed pipelines is the shortest distance between surface wells to permit the interconnection whilst minimising disruption to the property owner and impact to the environment. The majority of the surface pipelines follow existing boundary fence lines and range in diameter from 250 mm at the wellhead up to 600 mm for the main trunk pipeline to the extraction plant.

2.4 Processing of Extracted Gas

2.4.1 Overview

Extracted gas from the goaf area of the mine will be processed via a combination of the following three methods (in order of preference):

1. Electricity Generation – gas will be piped to the EDL Power Station at Appin Colliery and used for electricity generation; and/or

2. Onsite Flaring – gas will be flared onsite at the extraction plant using a mobile flaring unit if ongoing venting occurs; or
3. Onsite Venting – gas will be vented onsite at the extraction plant using a ventilation stack.

The majority of the extracted gas will be reticulated to the EDL Power Station for electricity generation. In the event that flow rates exceed the capacity of the extraction plant, power station and reticulation system, a small amount of venting to the atmosphere will occur to maintain safety. If ongoing venting occurs, BHPBIC will consider the installation of on-site flares co-located with the extraction plant to abate GHG emissions.

A description of each of the processes listed above is provided in the following sections, along with the likely distribution and quantity of gas flow to each process.

2.4.1 Electricity Generation

BHPBIC currently supply methane gas to the EDL Gas Fired Power Stations located at Appin West Mine Pit Top and Appin No. 2 Shaft. The EDL operated power stations consist of a series of gas engines that generate electricity. EDL supply electricity to BHPBIC's mining activities and to the NSW grid thus reducing demand on coal fired power stations.

The proposed goaf gas drainage system will be connected to the existing underground gas drainage system servicing Appin Colliery, which contains a connection to EDL via the underground workings. A downhole on the western side of the Hume Highway on the property described as Lot 1 DP 576136 will be constructed to connect into the existing underground drainage system within the workings (refer **Annex A**). This will allow the goaf gas drawn from Longwalls 703 and 704 to combine with other methane gas in the existing drainage system en-route to the Appin West Power Station.

BHPBIC are seeking approval to underbore the Hume Highway and Main Southern Rail Line to provide a connection between the two drainage networks for Longwalls 703 and 704, on either side of the Hume Highway. This approval would facilitate the conveyance of the goaf gas drawn from Longwall 703 (in addition to Longwall 704) to the EDL Power Station using only one extraction plant.

The EDL Power Stations have sufficient capacity to utilise this additional goaf gas as it is supplemented by external natural gas sources where mine/goaf gas is not readily available. The goaf gas from this specific project will therefore displace the externally sourced natural gas required to make up sufficient volumes, thus reducing EDL's and the Project's GHG emissions.

This electricity generation process burns methane to minimise greenhouse gas emissions and uses the heat generated to create electricity. As EDL supply some of this electricity to BHPBIC for their mining operations, this reduces BHPBIC's net use of electricity drawn from the grid as well as minimising GHG emissions.

Methane in both the EDL Gas Fired Power Stations (and any flare units) is oxidised to carbon dioxide according to **Equation 1**.

Equation 1: Methane Oxidation

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O + \text{heat}$$

$$1 \text{ mole } CH_4 \rightarrow 1 \text{ mole } CO_2$$

$$1 \text{ tonne } CH_4 \rightarrow 2.75 \text{ tonne } CO_2$$

$(21 \text{ t } CO_{2\text{-}e})$ $(2.75 \text{ t } CO_{2\text{-}e})$

Carbon dioxide (CO_2) is 21 times less potent a GHG than methane (CH_4). This is based on methane's Global Warming Potential (GWP) of 21 and carbon dioxides GWP of 1. Both utilisation by

EDL and flaring of the goaf gas effectively reduces GHG emissions by 18.25 tonnes of carbon dioxide equivalent units (t CO_2-e) per tonne of methane converted to carbon dioxide.

The gas engines used in the EDL Power Station maximise methane conversion whilst maintaining NOx and other air pollutant levels below the limits prescribed in their Environment Protection Licences. The supply of the goaf gas from this project to the EDL Power Station will not result in any additional NOx or other air pollutant emissions above their consented licence limits as the goaf gas from this project will displace the required amounts of natural gas sourced externally.

2.4.2 Flaring

Flaring the goaf gas from the extraction plant may occur onsite via a mobile flaring unit situated within the extraction plant compound. The procedure known as flaring operates by surface level equipment burning the goaf gas as it is extracted from the goaf. The flaring of goaf gas is desirable as the combustion of methane produces carbon dioxide and water, therefore lowering the GWP of the discharged gas and overall GHG emissions (see Equation 1 and associated explanation).

Purpose built enclosed gas combustion units burn the gas cleanly and in a controlled manner. The flame is not visible as the combustion is completely enclosed and controlled within the stack (refer **Figure 2.4** on the following page).

Any flare unit will be co-located with the goaf gas extraction unit. A flaring unit may be located within the contingency extraction plant location at Lot 7 DP250231 (refer **Annex A**), if the underbore connection is not approved or implemented.

The capacity of the proposed flaring system will be in the order of 800 L/s, which meets the expected maximum flow rate of the extraction plant. In the event that flow rates exceed 800 L/s, or flaring unit breakdown and/or maintenance occurs, a small amount of venting to the atmosphere via the discharge ventilation stack will occur to maintain safety.

2.4.3 Onsite Venting at Extraction Plant

Emergency venting of goaf gas from the extraction plant will occur via a discharge stack, to be located remote from the extraction plant compound (refer **Figure 2.3**). The discharge of goaf gas to the atmosphere is the least desirable application for the gas because the goaf gas has a high concentration of methane, which has a higher GWP than carbon dioxide (NGA, 2008).

Discharge occurs via a vertical discharge stack situated at least 100 m from the extraction plant for safety reasons (refer **Figure 2.5**). Irrespective of the goaf gas management option selected, a vertical gas discharge stack will be required for emergency venting upon failure/shut down of gas surface management equipment or in the event that gas flow exceeds the capacity of the utilisation or flaring system.

Figure 2.4 – Enclosed Goaf Gas Flaring Units

Figure 2.5 – Vertical Goaf Gas Discharge Stack

2.5 Extracted Gas Flow Properties

2.5.1 Raw Coal Extraction Volumes

The mass of Run of Mine (ROM) coal to be extracted from Longwalls 703 to 704 is estimated to be approximately 6.6 Mt. This will be mined over a period of approximately 1.7 years. This estimate is based on an assumed ROM coal density of 1.5 t/m^3, and a mining progression rate of 50 m per week. A breakdown of the amount of ROM coal estimated to be mined per financial year from Longwalls 703 and 704 is provided in **Table 2.2**.

Table 2.2 – ROM Coal Extraction Quantities from Longwalls 703-704 per FY

Quantity	FY2010	FY2011	FY2012	TOTAL
ROM Coal Volume (m3)	1,720,589	2,605,871	107,091	4,433,550
ROM Coal Mass (t)	2,580,883	3,908,806	160,636	6,650,325

2.5.2 Coal Seam Gas Content and Composition

Coal seam gas from the Bulli Seam comprises primarily of methane (>85 %), carbon dioxide (~8 %), and a number of other gases including oxygen, nitrogen, hydrogen, ethane, propane, argon, and butane. A typical breakdown of coal seam gas composition is provided in **Table 2.3**. The energy content of the goaf gas is approximately 35 MJ/m^3 (Heggies, 2008).

Table 2.3 – Typical Composition Coal Seam Gas from the Bulli Coal Seam (Heggies, 2008)

Gas	O_2	Ar	CH_4	CO	CO_2	H_2	C_2H_6	Propane	n-butane	i-butane
%	0.03	3.06	86.80	0.00	7.75	0.19	1.72	0.56	0.12	0.16
%	0.03	2.99	86.91	0.00	7.76	0.19	1.73	0.54	0.12	0.16

Estimates of cumulative Specific Gas Emissions (SGE) for previously mined Appin Longwalls 402 to 405 showed that SGE were in the range of 35 to 40 m^3/t ROM coal mined (Self, 2004). This value is representative of the volume of gas that is liberated from the Bulli Seam and surrounding strata per tonne of ROM coal mined at Appin Colliery. Based on this SGE, it is estimated that the total volume of gas that will be liberated by the mining of Longwalls 703 to 704 is within the range of approximately 230 to 265 million m^3.

Approximately 5 to 10 % of SGE leave via the goaf wells, approximately 25 to 30 % is captured in floor holes drilled into the underlying strata (if used), and the remaining 60 to 65 % is diluted in the Mine Ventilation Air (MVA) system (Heggies, 2008).

It is noted however, that baseline emissions used in this assessment were estimated using the National Greenhouse Accounts methodology (NGA, 2008) for calculating fugitive emissions from underground coal mining. The use of the NGA Factors methodology was specifically requested in the DGR's issued for this project, and is described in more detail in **Annex B**.

2.5.3 Extracted Gas Flow Distribution

As described in **Section 2.4**, coal seam gas extracted via the proposed extraction system will be either piped to EDL for energy generation, flared onsite, or vented to the atmosphere, with the vast majority of extracted gas being either used for electricity generation at the EDL Power Station or flared onsite.

BHPBIC's preferred management strategy for this project is to convey extracted goaf gas from both longwalls to the EDL Power Station at Appin for use in energy generation. However, this will only be achievable if approval is granted to underbore the Hume Highway and Main Southern Rail Line to connect the drainage network from Longwall 703 to that of Longwall 704. If the Hume Highway and Main Southern Rail Line underbore is not approved, only extracted gas from Longwall 704 will be piped to EDL, with the extracted gas from Longwall 703 proposed to be flared onsite. This is because the connection to the existing underground EDL drainage network is only available via the downhole above the workings on the western side of the Hume Highway. In either case, it is likely that a small amount of gas will be vented onsite in the event of plant breakdown, or the extracted gas flow rate exceeding system capacity to accept the gas.

A breakdown of the likely distribution of gas for each of these scenarios is provided in **Table 2.4**. The GHG emission outcome for both scenarios is the same.

Table 2.4 – Likely Distribution of Gas Flow Streams

Extraction Phase / Operational Scenario	Percentage of Extracted Gas		
	Electricity Generation	Onsite Flaring	Onsite Venting
MRD & Vertical Boreholes, with Approval to Underbore Hume Highway and Main Southern Rail Line	99%	0%	1%
MRD & Vertical Boreholes, without Approval to Underbore Hume Highway and Main Southern Rail Line	52%	47%	1%

2.5.4 Estimated Extraction Volumes

The volume of gas that will be extracted has been estimated based on the anticipated extraction flow rate and duration of 800 L/s and 1.7 years, respectively.

It is anticipated that the average gas flow rate per borehole will be approximately 400 L/s. However, it is likely that the extraction plant will extract gas from a number of boreholes (simultaneously) at any one time. Therefore, it is assumed that the extraction plant will be operating at maximum capacity of 800 L/s over the duration of the drainage phase, which is estimated to be approximately 1.7 years or 89 weeks. This equates to a total gas extraction volume via the goaf gas drainage system of approximately 43 million m^3.

Table 2.4 above shows the likely distribution/management of the extracted gas, which will vary depending on whether or not approval is granted to underbore the Hume Highway and Main Southern Rail Line.

3 Greenhouse Gas Assessment

3.1 Introduction

This Greenhouse Gas (GHG) assessment has been undertaken using methodology outlined in the *National Greenhouse Accounts (NGA) Factors* (2008) and using emissions factors tabulated in that document and industry best practice.

The NGA Factors (2008) workbook was produced by the Department of Climate Change, and replaces the AGO Factors & Methods Workbook (2006). All methodologies are underpinned by frameworks outlined in documents produced by the Intergovernmental Panel on Climate Change (IPCC) and the United Nations Framework Convention on Climate Change (UNFCCC) with due regard to the Kyoto Protocol.

Policies devised by the IPCC and UNFCCC are accepted as the internationally-spanning frameworks designed for intergovernmental efforts to tackle the challenges posed by climate change.

A description of methodology and calculations used in this GHG assessment is provided in **Annex B**.

3.2 Greenhouse Gas Assessment Definitions

Consistent with the protocols of IPCC, UNFCCC, and NGA Factors (2008), three scopes of GHG emissions have been defined for this project. These include Scope 1, Scope 2, and Scope 3 emissions, each of which is defined below:

- **Scope 1** – Scope 1 emissions include direct emissions from sources within the boundary of an organisation such as fuel combustion and manufacturing processes.
- **Scope 2** – Scope 2 emissions include indirect emissions from the consumption of purchased electricity, steam or heat produced by another organisation. Scope 2 emissions result from the combustion of fuel to generate electricity, steam, or heat and do not include emissions associated with the production of fuel. Scopes 1 and 2 are carefully defined to ensure that two or more organisations do not report the same emissions in the same scope.
- **Scope 3** – Scope 3 emissions include all other indirect emissions that are a consequence of an organisation’s activities but are not from sources owned or controlled by the organisation. Examples of Scope 3 emissions include indirect emissions associated with the extraction/production of fuels used onsite fuel extraction and line loss associated with the consumed electricity, transport of product outside the organisation, and emissions associated with end use of product.

The *Greenhouse Gas Protocol 2004* (WBCSD & WRI) considers reporting of Scope 3 emissions to be optional in the GHG inventory calculation of a project, as they are produced by third party organisations and form part of the GHG inventories of those third parties. Also, reporting Scope 3 emissions can result in double-counting of emissions and can potentially make comparisons between organisations and projects problematic, and yield emission values higher than the true value.

Notwithstanding the above, we have included Scope 3 emissions in this study from as many sources as practical, and from sources where data were available as a review of previous Part 3A applications determined in NSW show a strong desire from DoP for this information to be included in GHG assessments for proposed developments.

There are several different types of greenhouse gases (e.g. carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), etc.) and each type of greenhouse gas has a different Global Warming Potential (GWP).

To allow a quantitative comparison between the emissions of different types of gases, the IPCC has defined a universally comparable unit referred to as the GWP, which are provided in Appendix 1 of NGA Factors (2008). The GWP is the equivalent of non-carbon dioxide gas emissions given in tonnes of carbon dioxide equivalent (CO_2-e). Emissions from non-carbon dioxide gases are converted to t CO_2-e by multiplying the emission of each non-carbon dioxide gas by its GWP (e.g. 1 t CH_4 = 21 t CO_2-e).

3.3 Greenhouse Gas Emissions Sources

This assessment considers emissions associated with both the development and ongoing operation phases of the project. Scope 1 emissions have been defined as point source emissions that occur as result of coal seam gas liberation during the mining of Longwalls 703 to 704, or operator controlled activities directly associated with the proposed goaf gas drainage project (including setup or installation works and ongoing power supply to the extraction equipment). Scope 1 emissions will include direct point source emissions resulting from:

- Diesel combustion in machinery engines and generators during construction and installation of the proposed goaf gas drainage infrastructure;
- Drilling of boreholes (drill rig diesel combustion);
- Diesel combustion during transportation of construction material, extraction plant, flaring units, and associated equipment (incl. pipeline network);
- Fuel combustion during employee travel associated with construction / installation works;
- Diesel combustion from onsite generators used to supply power to the goaf extraction plant and flaring units during the operational phase of the project;
- Production of CO_2 and N_2O during onsite flaring of the extracted gas; and
- Emission of CO_2 and CH_4 during onsite venting of extracted gas directly to the atmosphere.

We note that emissions resulting from the combustion of extracted gas at the EDL Power Stations servicing Appin Mine are considered as occurring outside the organisation under the jurisdiction of a third party and as such these have been considered as Scope 3 emissions in this assessment (refer below).

There are no Scope 2 emissions associated with the project as this assessment assumes that all energy requirements during the construction and operational phases of the project will be supplied by onsite diesel generators, which have been included in Scope 1 emissions.

Scope 3 emissions in this assessment include:

- Direct point source emissions resulting from the production of CO_2 and N_2O during combustion of the extracted gas at EDL's Power Stations; and
- Indirect extraction emissions associated with all Scope 1 fuel combustion emissions listed above (these emissions occur during the extraction and transportation of fuels used for energy).

3.4 Greenhouse Gas Inventory

The various Scope 1, 2, and 3 GHG emissions associated with the project and included in this GGA are summarised in **Table 3.1**.

Table 3.1 – Scope 1, 2, & 3 Emissions from Appin Area 7 Goaf Gas Drainage Project

Scope 1 Emissions	Scope 2 Emissions	Scope 3 Emissions
• Diesel combustion during construction and installation works; • Drilling of MRD boreholes and vertical wells; • Diesel combustion during transportation of plant and materials; • Fuel combustion during employee travel associated with construction / installation works; • Diesel combustion resulting from ongoing power supply to the goaf extraction plant and flaring units; • Production of CO_2 and N_2O during onsite flaring of the extracted gas; and • Emission of CO_2 and CH_4 during from onsite venting of extracted gas directly to the atmosphere.	N/A	• Production of CO_2 and N_2O during combustion of extracted gas at EDL's Appin Colliery Power Station; and • Indirect extraction emissions associated with all Scope 1 fuel combustion emissions listed in column 1 (these emissions occur during the extraction and transportation of fuels used for energy).

3.5 Methodology

The methodology used in this GHG assessment is described in **Annex B**. The assessment protocols, methodologies, and greenhouse gas estimates were derived primarily from the *NGA Factors (2008)*, with due consideration given to the following reference documents:

- *Tracking to the Kyoto Target, Australia's Greenhouse Emissions Trends, 1990 to 2008-2012 and 2020*, Department of Climate Change, Australia;
- *State and Territory Greenhouse Gas Inventories 2005*, Australian Greenhouse Office, Department of the Environment and Water Resources, Australia;
- *NSW Greenhouse Plan*, November 2005, New South Wales Greenhouse Office, Australia;
- *Greenhouse Gas Protocol 2004*, The World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI);
- *Projected Changes in Climatological Forcing For Coastal Erosion in NSW*, A Project Undertaken for the NSW Department of Environment and Climate Change, McInnes et al., CSIRO 2007; and
- *Economic Impact of Climate Change Policy: The Role of Technology and Economic Instruments*, ABARE, July 2006.

Goaf gas quantification and volume to mass conversion was undertaken using the ideal gas law.

Baseline emissions were estimated using the NGA Factors (2008) methodology for estimating fugitive emissions from underground coal mines (gassy mines), which is the industry accepted and agency preferred method. This methodology accounts for release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata (NGA, 2008).

A detailed explanation of the methodology used is provided in **Annex B**.

3.5.1 Source Data and Assumptions

Source data used in this GGA was obtained from Illawarra Coal in the first instance, sound reference data in the second instance, or estimated based on reasonable assumptions where such data was not available. Source data used is provided in **Table 3.2**.

Table 3.2 – Source Data Used in this Assessment

Parameter	Data Used	Source
Number of Vertical Boreholes	7	BHPBIC conceptual gas drainage layout (refer **Annex A**)
Average Vertical Borehole Depth	500 m	Average Depth of Coal Seam
Total Length of MRD Boreholes	3615 m	Estimated based on BHPBIC conceptual gas drainage layout (refer **Annex A**)
Length of Extraction Surface Pipe Network	3445 m	BHPBIC conceptual gas drainage layout (refer **Annex A**)
Extraction Plant Power Supply	175 kVA generator consuming 3500 L/week of diesel	Heggies, 2008
Extraction Plant Flow	800 L/s	Assumed maximum capacity of extraction plant
Operational Duration of Extraction Plant	89 weeks	Based on mining rate of 50 m per week, combined length of both longwalls of 4239 m and a equipment changeover time of 4 weeks
Seam Gas Composition	Refer **Table 2.3**	Heggies, 2008
Extracted Gas Flow Distribution	Refer **Table 2.4**	BHPBIC

The following assumptions have been made in estimating GHG emissions from the project:

- Goaf gas emissions follow the ideal gas law (i.e. used for volume to mass conversions);
- Goaf gas emissions consist of 70 % seam gas, and 30 % MVA;
- ROM coal density assumed to be 1.5 t/m^3, with an average seam depth of 3 metres;
- Flaring units are delivered from Melbourne by truck;
- Fuel consumption of an excavator is 120 L/day for earthworks and pipeline installation;
- Earthworks duration of 4 days will be required for site levelling during construction activities;
- 6 workers will be travelling to and from the site each day during construction works, with an average return trip distance of 60 km (equivalent return distance from Wollongong);
- Construction / installation of infrastructure will occur over 15 weeks;
- Drill rig fuel consumption during drilling of vertical wells is 2 L/m;
- MRD drill rig fuel consumption is 4 L/m; and

- Pipeline lengths to be transported to the site in 6 m lengths, at 40 lengths per trip, with an average return distance of 60 km (equivalent return distance from Wollongong).

It is noted that some of the GHG emissions associated with the project are difficult to estimate because there is no sound methodology for estimating them, or it is difficult to define an accurate quantity. In all such instances, this GGA has taken a conservative approach by over estimating GHG emissions and quantities rather than underestimating. This rule has been applied generally across all GHG emission estimates. For example, in estimating the operational power consumption it was assumed that all electricity will be supplied to the project via onsite diesel generators with no connection to the grid. This is conservative as power supplied via a diesel generator results in a higher per kWh emission then electrical energy supplied via the grid.

3.6 Results

3.6.1 Baseline Emissions

Baseline emissions for the mining of Longwalls 703 and 704 were estimated using the NGA Factors (2008) methodology for estimating fugitive emissions from underground coal mining, using the emissions factor for gassy underground coal mines. This methodology accounts for release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata (NGA, 2008).

Baseline emission estimates represent the emissions that are likely to occur due to the mining of Longwalls 703 and 704 without the implementation of the goaf gas extraction and utilisation project (i.e. all gas would be vented directly to the atmosphere via the MVA). The estimated baseline emissions are provided in **Table 3.3**.

Table 3.3 – Baseline Emissions

Operation	Total Emission (kt CO_2-e)	Equivalent Annual Emission (kt CO_2-e/yr)
Baseline Fugitive Emissions from Appin Mine due to Mining of Longwalls 703 to 704	2028	1193

3.6.2 Project Emissions

Emissions associated with the project have been categorised into Scope 1 and Scope 3 emissions. As described in **Section 3.2** there are no Scope 2 emissions associated with the project as it has been conservatively assumed that all power supply requirements will be met using onsite diesel generators. Scope 3 emissions arise due to the extraction and transportation of fuels used for energy, and combustion of extracted gas at the EDL Power Station, which is under the jurisdiction of a third party.

Project emissions associated with both the construction and operational phase of the project are summarised in **Table 3.4**. A detailed breakdown showing calculations and emissions for each source is provided in **Annex C**.

As described in **Section 2.5.3**, BHPBIC's preferred extracted goaf gas flow distribution will be to direct all extracted gas to EDL for electricity generation (refer refer **Table 2.4**, scenario 1 - with Approval to Underbore Hume Highway and Main Southern Rail Line). Therefore, we have based our assessment on this preferred option. We note however, that regardless of which flow distribution scenario is implemented, the same quantity of methane will be converted to carbon dioxide in accord with **Equation 1** (page 8 of this report) by onsite flaring. Therefore the total post-project emissions presented in this assessment are representative of both possible flow distribution scenarios.

Table 3.4 – Project Emissions

Operation	Scope 1 Emissions (kt CO_2-e)	Scope 3 Emissions (kt CO_2-e)	Total Emissions (kt CO_2-e)	Equivalent Annual Emission (kt CO_2-e/yr)
Project Emissions (Construction / Setup / Installation Works)				
Diesel Combustion During Construction / Setup / Installation Works	0.078	0.006	0.084	0.049
Petrol Fuel Combustion from Employee Travel	0.0062	0.0005	0.0067	0.0039
Project Emissions (Operational)				
Emissions from EDL Combustion and Onsite Venting	4.0	58.0	62.0	36.5
Extraction Plant and Flaring Unit Power Supply (Diesel Combustion)*	0.899	0.1	0.9	0.5
Total Project Emissions	4.9	58.1	63.0	37.1

*BHPBIC are in consultation with Integral Energy and propose to connect the preferred extraction plant located on the property described as Lot 2 DP576136, to the existing 11kVA mains located on the adjacent property described as Lot 1 DP576136. This GGA has taken a conservative approach in assessing GHG emissions associated with proposed project and has therefore assumed the worst case scenario in that the preferred extraction plant and contingency extraction plant (if utilised) will be powered by a diesel generator.

Should the preferred extraction plant be able to be powered by electricity and not diesel, the actual GHG emissions associated with the operation of the extraction plant will be significantly lower due to this; however, the GHG emissions determined by this GGA has assumed the use of diesel fuel for operation of the extraction plant/s.

The emission total for all Scope 1 and Scope 3 emissions is 0.09 kt CO_2-e for the construction / installation phase of the project and 62.9 kt CO_2-e for the ongoing operational phase of the project. It is noted that emissions that occur during the construction / installation phase of the project are insignificant in comparison with the operational emissions, making up only 0.14 % of total project emissions.

The total post-project emissions, including those that will occur via the Appin Mine MVA, are provided in **Table 3.5**.

Table 3.5 – Total Post-Project Emissions from Appin Mine

Operation	Scope 1 Emissions (kt CO_2-e)	Scope 3 Emissions (kt CO_2-e)	Total Emissions (kt CO_2-e)	Equivalent Annual Emission (kt CO_2-e/yr)
Total Project Emissions (Goaf Gas Drainage and Utilisation Project)	4.9	58.1	63.0	37.1
Post Project Fugitive Emissions (Appin Mine MVA)	1631	N/A	1631	959
Total Post-project Emissions at Appin Mine	1636	58.1	1694	996

Table 3.5 shows that the total post-project emissions at Appin Mine are 1694 kt CO_2-e. Of this total, 96.3 % is made up of Appin Mine MVA emissions, and the remaining 3.7 % is associated with the proposed goaf gas drainage and utilisation project.

3.6.3 Reduction in Emissions from Appin Mine Resulting from the Project

The project will result in an overall net reduction in GHG emissions at Appin Mine of 334,000 t CO_2-e over the 1.7 year project duration, which is equivalent to an annual average of 196,000 t CO_2-e/yr. This is due to the destruction of methane and conversion to CO_2 that takes place during combustion for power generation at EDL and/or onsite flaring. Without the proposed project, this methane would be emitted to the atmosphere in the Appin MVA via upcast ventilation shafts. The estimated net reduction in emissions predicted to occur at Appin Mine as a result of the project is provided in **Table 3.6**.

Table 3.6 – Appin Mine GHG Emission Reductions Resulting from the Project

Operation	Total GHG Emissions (kt CO_2-e)	Equivalent Annual GHG Emission (kt CO_2-e/yr)
Baseline Emissions	2028	1193
Total Post-Project Emissions	1694	996
Net Reduction in Appin Mine Emissions due to Goaf Gas Extraction and Utilisation Project	334	196

3.6.4 Emission Offsets from Power Generation using Extracted Gas

The use of extracted goaf gas for electricity generation at the EDL Power Station will result in a GHG emission offset, because the electricity generated using extracted goaf gas will displace power that would otherwise have been generated using a coal fired power station. Assuming that each megawatt hour (MWh) of electricity generated using extracted goaf gas from the proposed project will directly substitute for electricity generated at a coal fired power station, it is estimated that the proposed project will result in an offset of 0.89 t CO_2-e per MWh of power generated. This calculation uses the NGA Factors (2008) methodology for estimating emissions from electricity generation using a coal fired power station.

The minimum volume of extracted goaf gas that will be conveyed to the EDL Power Station has been conservatively estimated to be approximately 16 million m^3 (which excludes extracted gas from Longwall 703 as a worst case scenario), and the average energy content of extracted coal seam gas is 35 MJ/m^3 (Heggies, 2008). Therefore, the total amount of stored energy in the extracted goaf gas that will be conveyed to EDL is approximately 560 million MJ (equivalent to approximately 155,000 MWh). While it is noted that the EDL power generation process is not 100 % efficient, and therefore not all of this energy will be converted to usable electrical energy, the amount of electricity generated from the extracted gas will still be in the order of 50,000 - 100,000 MWh. This equates to a GHG emission offset of approximately 44 - 89 kt CO_2-e, which is significant in relation to the overall project emissions.

While the GHG emission offset resulting from electricity generation has not been quantified in **Table 3.6** above, it still represents a significant project benefit and should be considered in appraising the environmental benefits of the project.

3.7 State, National, and Global Emissions Comparisons

The total New South Wales (NSW) GHG emissions in 2005 were reported to be approximately 158.2 Mt CO_2-e and are likely to be a similar quantity in 2009/2010. When compared to this figure, the annual equivalent baseline emissions that would occur without implementation of this project represent approximately 0.75 % of the 2005 NSW emission total. With the implementation of the proposed goaf gas drainage project, the estimated post-project annual equivalent emissions are reduced to approximately 0.6 % of the 2005 NSW total GHG emissions. This represents a reduction of approximately 0.15 % from baseline emissions due to the proposed goaf gas drainage project.

The total Australian GHG emissions in 2005 were estimated to be 559.1 Mt CO_2-e and increasing to over 560 Mt CO2-e in the current period. When compared with national emission totals, the baseline and post-project annual equivalent emissions represent approximately 0.21 % and 0.18 % of the 2005 national emission total, respectively. This represents a reduction in annual GHG emissions of approximately 0.03 % of the 2005 national emissions total.

The world total greenhouse gas emissions are predicted to increase to 41,825 Mt CO_2-e in 2010. When compared to this total, the annual reduction in GHG emissions associated with the project represents approximately 0.00047 % of the annual global emissions total.

4 Impact Assessment

Climatic change involves complex interactions between climatic, biophysical, social, economic, institutional and technological processes. There is a general consensus among the scientific community that the world is warming due to the release of emissions of carbon dioxide and other GHGs from human activities including industrial processes, fossil fuel combustion and changes in land use, such as deforestation (Pew Center on Global Climate Change 2007). The Fourth Assessment Report of the Intergovernmental Panel on Climate Change published in 2007 stated that most of the observed increases in globally averaged temperatures since the mid-20th century is very likely due to the observed increase in (human produced) greenhouse gas concentrations (IPCC 2007).

4.1 Global and National Climate

Global temperatures have increased since the earliest reliable data measurements began in the late 1800's (AGO 2007). During the past 100 years, average global surface temperatures have increased by 0.7°C and evidence suggests that 11 of the past 12 years were the warmest since 1860 (AGO 2007).

Scientists believe that the Earth's average temperature will rise by 1.1 to 6.4 °C from 1990 to 2100 if nations around the world do not act to control greenhouse emissions (AGO 2007).

Australia is vulnerable to changes in temperature and precipitation and Australia's vulnerability to climate change is intensified by already being a generally dry continent and experiencing high natural climate variability from year to year (Commonwealth Minister for Environment and Heritage Dr David Kemp 2003).

A few degrees of global warming will lead to more heat waves and fewer frosts. In Australia, the projected average warming of 0.4 to 2.0 °C by the year 2030 would lead to a 10 to 50 per cent increase in days over 35 °C at many places and a 10 to 80 per cent decrease in frosts experienced (AGO 2007).

4.2 Global and National Sea Level

Sea levels in Australia are naturally variable, although records indicate that sea levels have been rising by an increasing rate over the past 130 years. Records indicate that the sea level has risen by approximately 1 to 2 mm per year over the past 50 years and in the first half of the 19th century global sea levels were about 200 mm below the present levels (AGO Climate Trends 2007).

Sea level is likely to rise by 18 to 59 cm by 2100, but this does not include possible changes in big ice sheets such as Greenland and the Antarctic that could lead to more rapid sea level rise. Low-lying coastal areas and islands may be inundated more often by storm surges (IPCC 2007).

Impacts of sea level rises may include increased intensity and frequency of storm surges, increased erosion, loss of important wetlands and mangroves, impact on coastal ecosystems (i.e. coral reefs), and impact on human settlements (CSIRO Marine Research 2007). Low lying coastal terrain may become inundated resulting in beaches being eroded, infrastructure being damaged or destroyed, and human injuries and/or fatalities. Sea level rises may have impacts on soft sediment shorelines and intertidal ecosystems, which will especially be vulnerable to change with additional impacts from extreme events.

4.3 NSW Impacts

Possible impacts of climate change in Australia are addressed on the AGO webpage (AGO Climate Change Impacts 2007). Projected impacts listed for NSW include:

- New South Wales is expected to become warmer with more hot days and less cold nights.
- By 2030 the annual average number of days over 35 °C in Sydney could grow from the current 3 to 4-7 days, in Canberra from 5 to 6-12 days and in Cobar from 41 to 45-65 days.
- Growth in peak summer energy demand is likely, due to air-conditioning use, which may increase the risk of blackouts.
- Warmer temperatures and population growth are likely to cause a rise in heat-related illness and death for those over 65; increasing in Canberra from the current 14 deaths annually to 37-41 by 2020 and 62-92 by 2050. In Sydney increases are projected in annual deaths from the current 176 to 364-417 by 2020 and 717-1,312 by 2050.
- Warmer conditions may also help spread vector-borne, water-borne and food-borne disease further south. These health issues could increase pressure on medical and hospital services.
- Urban water security may be threatened by projected increases in demand and climate-driven reductions in water supply.
- Little change in annual rainfall and higher evaporation would likely lead to less runoff in rivers in many catchments by 2030. Run-off across the Murray-Darling Basin may decrease 10-25 percent by 2050.
- More frequent and severe droughts, with greater fire risk, are likely.
- By 2020 the annual number of days with very high or extreme fire danger could average 13-14 in Richmond (now 11.5), 26-29 in Canberra (now 23) and 53-57 in Wagga Wagga (now 50).
- By 2020 a 10-40 percent reduction in snow cover is likely with potentially significant consequences for alpine tourism and ecosystems.
- Some agricultural crops may benefit from higher CO_2 concentrations however protein content is likely to decline.
- Frost-sensitive crops, such as wheat, may respond well to some warming however more hot days and less rainfall may reduce yields.
- Adverse effects for agriculture include reduced stone fruit yields in warmer winters, livestock stress and an increased prevalence of plant diseases, weeds and pests.
- CO_2 benefits experienced by forestry may be offset by a decline in rainfall, more bushfires and changes in pests. Centres dependent upon agriculture and forestry may be adversely affected.
- Increases in extreme storm events are expected to cause more flash flooding affecting industry and infrastructure, including water, sewerage and stormwater, transport and communications, and may challenge emergency services.
- In coastal areas infrastructure is vulnerable to sea level rise and inundation.

4.4 Abatement Measures

BHPBIC abates approximately 2.5 Mt CO_2-e/year through utilisation of methane for energy generation, and is one of NSW's largest GHG abaters. BHPBIC has a proud history of developing and implementing technological innovations to reduce GHG emissions, and implements a number of abatement measures including the WestVAMP project, conveyance of drained coal seam gas for energy generation at EDL's Appin and Appin West Power Stations, and the development of Energy Savings Plans. Each of these is described further in the following sections.

4.4.1 WestVAMP

West Cliff Ventilation Air Methane Project (WestVAMP) is a major project that is substantially reducing GHG emissions from BHPBICs West Cliff Colliery. The WestVAMP project is the final step in proving the thermal flow reversal reactor technology, which was first piloted at BPHBICs Appin Colliery in 2001. The technology is capable of mitigating the bulk of the company's remaining GHG emissions, while producing 6 MW of electricity.

BHPBIC has built a $13 million electricity plant at West Cliff that oxidises the methane in Mine Ventilation Air (MVA) that would otherwise be vented into the atmosphere and contribute to global warming. The West Cliff Ventilation Air Methane Project (WestVAMP) utilises 20 % of West Cliff's available MVA.

WestVAMP uses VOCSIDIZER™ technology produced by Megtec Systems, which converts low concentration methane to carbon dioxide and water vapour through a flameless combustion process. High efficiency heat exchangers will recover large levels of thermal energy to produce steam. This steam will be used to drive a conventional steam turbine to produce 6 MW of electricity that will be used by the West Cliff Colliery and put back into the NSW grid.

WestVAMP is achieving a reduction in GHG emissions of up to 250,000 t CO_2-e per year. This is equivalent to producing enough electricity for 20,000 homes, or removing emissions from 45,000 cars from the environment each year.

4.4.2 Energy Developments Limited – Appin and Tower Power Stations

Coal seam methane from BHPBIC's Appin/Appin-West and West Cliff Collieries is supplied to two interconnected gas fired power stations operated by Energy Developments Limited (EDL) at Appin No 2 shaft and the Appin West pit top (formally known as Tower). The 94 MW of electricity generated is supplied to Integral Energy and is sufficient to supply all BHPBIC's electricity requirements and that of approximately 90,000 homes. The power station abates greenhouse gas emissions by up to 2.2-2.5 Mt CO_2-e/year.

4.4.3 Energy Savings Plans

All BHPBIC mines have developed and are now implementing Energy Savings Plans. Opportunities for reduced energy consumption have been identified and will contribute to reduced greenhouse gas emissions.

5 Alternatives for the Utilisation of the Goaf Gas

5.1 Overview

The Methane to Markets Coal Subcommittee and Project Network (MMCSPN) describe two viable options for use of coal mine methane or ventilation air methane. These are the combustion of methane and ventilation of waste heat to the atmosphere; or combustion of methane and capturing the energy released.

Both of these options consist of combusting methane, but only one captures the energy released from this combustion. MMCSPN stress, however, that capturing this energy is not always economically feasible and certain factors need to be taken into consideration, including (Creedy et al, 2001):

- Rate of gas production;
- Gas Reserves;
- Direct or indirect market for gas;
- Contract conditions; length of supply, gas availability, back up fuel source;
- Capital and operating costs;
- Availability and cost of alternate fuels;
- Existing energy distribution infrastructure; and
- Environmental, planning and regulations.

MMCSPN discuss that the decision of which option to use be environmental and economically feasibility.

BHPBIC's preferred option is to pipe goaf gas to pre-existing infrastructure located 5km away to convert methane into electricity at the EDL Power Station, with a small amount of venting only as necessary for safety reasons. This proposal maximises the potential to utilise the energy content of the goaf gas and reduce GHG emissions.

There are limited alternatives that are both environmentally and economically feasible, and the proposed project represents the most environmentally and economically feasible operation at this time. However, the limited alternatives for the utilisation of goaf gas are discussed in the following sections.

5.2 Increased Flare Capacity

Previous goaf gas drainage applications have used smaller capacity flaring units than those proposed for in this project. Flaring unit capacity in previous projects has generally been in the order of 125 L/s per unit. As part of this project, BHBPIC may use a state of the art flaring unit with a capacity of 800L/s in order to and minimise the amount of gas vented directly to the atmosphere, and maximise the amount of goaf gas extracted and oxidised, where ongoing venting occurs. The capacity of the proposed flare (if needed) is matched to the capacity of the extraction plant.

5.3 Installation of VAMP Plants at Other Ventilation Shaft Sites

The success of the trial VAMP plant at West Cliff Colliery has highlighted the feasibility of installing similar plants at other BHPBIC upcast ventilation shaft sites. It may be feasible, depending on environmental policy and economic conditions, to implement similar technology at other upcast ventilation shafts to firstly abate the methane within the MVA and secondly utilise the waste heat produced from the abatement process to power a turbine and produce energy.

Whilst VAMP plants provide a means of utilising the small percentage of coal seam gas present in MVA, they do not provide a feasible alternative to goaf gas extraction and as such the proposed project is still required to extract gas from the goaf to maintain a safe methane concentration in the MVA.

5.4 Increased Power Generation Capacity

The Appin and Douglas EDL Power Stations have capacities of 54 and 40 MW, respectively, and utilise a combined total of over 650,000 m^3 of methane per day (Heggies, 2008). The Appin Area 7 goaf gas extraction project proposes to extract seam gas at a maximum rate of 800 L/s, which equates to 69,120 m^3 per day. As such, the existing EDL Power Station at Appin has sufficient capacity to utilise the extracted gas from Longwalls 703 and 704, and the amount of extracted goaf gas that can be reused for electricity generation at EDL is not governed by power station capacity. Where there is a shortfall in the available extracted seam gas, the additional amount of gas is made up using sourced externally natural gas. Therefore the goaf gas extracted as part of the proposed project will displace the use of externally sources natural gas.

Therefore, an increase in power station capacity would not facilitate an increase in potential reuse of extracted gas from the proposed project. Furthermore, the project proposes to convey as much of the extracted gas as possible to the EDL, the amount of which will be maximised if approval is granted to underbore the Hume Highway and Main Southern Rail Line. This will provide a connection between the surface drainage networks for Longwalls 703 and 704 and facilitate drainage of extracted goaf gas from Longwall 703 extracted gas to EDL (in addition to the extracted goaf gas from Longwall 704).

6 Conclusions and Recommendations

This assessment shows that the project is likely to result in a net reduction in GHG emissions of approximately 334 kt CO_2-e (an annual equivalent of 196 kt CO_2-e based on a project timeframe of 1.7 years), which represents a reduction of 0.15 % of the NSW total annual GHG emissions. The utilisation of extracted coal seam gas at the EDL Power Station is also estimated to result in a minimum GHG emission offset of approximately 44 - 89 kt CO_2-e/yr.

BHPBIC are in consultation with Integral Energy and propose to connect the preferred extraction plant located on the property described as Lot 2 DP576136, to the existing 11kVA mains located on the adjacent property described as Lot 1 DP576136. This GGA has taken a conservative approach in assessing GHG emissions associated with proposed project and has therefore assumed the worst case scenario in that the preferred extraction plant and contingency extraction plant (if utilised) will be powered by a diesel generator.

Should the preferred extraction plant be able to be powered by electricity and not diesel, the actual GHG emissions associated with the operation of the extraction plant will be significantly lower due to this; however, the GHG emissions determined by this GGA has assumed the use of diesel fuel for operation of the extraction plant/s.

Greenhouse gas emissions have been linked to global climate change, and it is predicted that average temperatures will rise by up to 6.4 °C between 1990 and 2100 (AGO, 2007). The implications of this rise in temperature are increased flooding, droughts and heat waves, and a number of other environmental, social and economical impacts. BHPBIC is one of NSW's largest abaters of GHG emissions, abating approximately 2.5 Mt CO_2-e per year through projects such as WestVAMP, utilisation of extracted coal seam gas, and energy savings plans. The further reduction in GHG emissions associated with the proposed project demonstrates BHPBIC's ongoing commitment to sustainable mining practices and minimising GHG emissions.

The project proposes to convey as much of the extracted goaf gas to the EDL Power Station at Appin Colliery for energy generation as possible. Where utilisation of the goaf gas at EDL is not possible or cannot be routinely achieved then flaring of the gas will be considered. Both options result in significant reductions in GHG emissions. There are limited alternative gas management systems that are both environmentally and economically feasible, and represent a better environmental outcome than the proposed project. Notwithstanding this, the alternatives for the utilisation of goaf gas discussed in this assessment include:

- Increased flare capacity;
- Installation of VAMP plants at other ventilation shaft sites; and
- Increased power generation capacity at the existing EDL Power Stations.

We conclude that none of the above alternatives are feasible or reasonable in this instance and the project represents the most environmentally and economically feasible alternative for the management of the extracted goaf gas.

We recommend that the goaf gas extraction project aim to maximise the amount of gas utilised in the following order of priority:

1. Utilisation for energy generation at the EDL Power Station; and
2. Onsite flaring if ongoing venting occurs;
3. Emergency venting.

BHPBIC will minimise the amount of goaf gas vented directly to the atmosphere and the consumption of diesel and petrol fuel wherever possible during the construction and installation phase of the project.

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Annex A

A. Gas Drainage Layout Plans

Lot 4 Pipes Removed
Lot 21 Downcast Borehole Removed
Lot 3 Well Relocated
MRD Well Trajectories Shown

0 50 100 200
Metres

bhpbilliton
Carbon Steel Materials
Illawarra Coal Holdings Pty Ltd
Asset Development
Gas & Ventilation

Appin Area 7
AREA 7 GOAF DRAINAGE PROJECT
703 & 704 WELLS & PIPELINES

Date: FEB, 2009
Author: Mick Loney
Signed Off:

NTS
Horizontal Datum
MGA - Zone 56

GV-A7-03
Version 3

290000 291000 292000

bhpbilliton
Carbon Steel Materials
Illawarra Coal Holdings Pty Ltd
Asset Development
Gas & Ventilation

Lot 4 Pipes Removed

0 50 100 200 Metres

Appin Area 7
AREA 7 GOAF DRAINAGE PROJECT
DETAIL VIEW - LOT3

Date: FEB, 2009
Author: Mick Loney
Signed Off:

NTS
Horizontal Datum
MGA - Zone 56

GV-A7-02f
Version 3

291000

6216000

6216000

291000

bhpbilliton

Carbon Steel Materials

Illawarra Coal Holdings Pty Ltd
Asset Development
Gas & Ventilation

Lot 4 Pipes Removed
Lot 21 Downcast Borehole Removed
Lot 3 Well Relocated

0 50 100 200 Metres

Appin Area 7
AREA 7 GOAF DRAINAGE PROJECT
703 & 704 GOAF PLANT LOCNS

Date: FEB, 2009
Author: Mick Loney
Signed Off:

NTS

Horizontal Datum
MGA - Zone 56

GV-A7-02
Version 2

Annex B

B. Methodology

1. Methodology

All methodology used in this assessment for the estimation of GHG emissions have been in accord with the *National Greenhouse Accounts (NGA) Factors (2008)* document in the first instance and/or in accord with sound scientific and engineering principles where NGA Factors have proved inadequate for the required calculations. The specific methodologies used in each calculation are given in the following sections. To ensure emissions were not underestimated, all calculations were conservative in nature.

1.2 Source Data

All source data used in this assessment was obtained from stable and reliable sources where possible or estimated based on engineering experience and reasonable assumptions where sound reference data was not available.

A list of source data used in the assessment is provided in **Section 3.5.1** of the GGA report.

1.3 Baseline Emissions

Baseline emissions were calculated using the NGA Factors (2008) methodology for estimating fugitive emissions from underground coal mining. This methodology accounts for release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata. The methodology can be found on page 19 of the NGA Factors (2008), and is described briefly below:

GHG emissions (t CO_2-e) = (Q x EF) / 1000

Where,

Q is the quantity of run of mine (ROM) coal extracted in tonnes; and

EF is the relevant emission factor expressed in t CO_2-e/t ROM coal, obtained from the *NGA Factors (2008)* document;

The EF for Gassy underground mines was used for the estimation of baseline emissions (NGA 2008, Table 6).

The mass of coal to be mined was calculated based on the plan view area of the longwall layout (refer Annex A), using an average coal seam thickness of 3m and a coal density of 1.5 t/m^3.

1.4 Emissions from Onsite Ventilation of Extracted Gas

Emissions were from onsite ventilation of extracted gas were estimated by converting the likely quantity of gas to be vented from a volume (in m^3) to a mass (in tonnes) using the ideal gas equation (i.e., $PV = NRT$). The mass of CH_4 was then converted to CO_2-e using the GWP for CH_4 (i.e., 21).

1.5 Emissions from Onsite Flaring and EDL Power Generation

Emissions from the onsite flaring and EDL combustion of extracted goaf gas were estimated using the NGA Factors (2008) methodology for fuel combustion of gaseous fuels, which can be found on page 12 of the NGA Factors (2008) booklet.

Emissions were calculated using the following formula:

GHG emissions (t CO_2-e) = (Q x EC x EF) / 1000

Where,

Q is the quantity of fuel consumed expressed by volume (m^3);

EF is the relevant emission factor expressed in kg CO_2-e/GJ, obtained from the *NGA Factors (2008)* document; and

EC is the energy content factor of the fuel type, expressed in GJ/m^3 (if Q is measured in GJ, EC=1), obtained from NGA Factors (2008).

An EC value of 37.7 x 10^{-3} GJ/t, and the emission factors for coal seam methane that is captured for combustion (NGA 2008, Table 2) were used in the calculations.

1.6 Fuel (Petrol and Diesel) Consumption Calculations

Emissions from the combustion of fuels (incl. diesel consumption during setup / installation works, materials haulage, employee transportation, and operational power supply to the goaf gas plants) during transportation was obtained from the NGA Factors (2008), were estimated using the NGA Factors (2008) methodology for fuel combustion of liquid fuels, which can be found on page 14 of the NGA Factors (2008) booklet.

Emissions were calculated using the following formula:

GHG emissions (t CO_2-e) = (Q x EF x EC) / 1000

Where,

Q is the quantity of fuel consumed expressed by volume (kL or GJ);

EF is the relevant emission factor expressed in kg CO_2-e/GJ, obtained from the *NGA Factors (2008)* document; and

EC is the energy content factor of the fuel type, expressed in GJ/kL (if Q is measured in GJ, EC=1), obtained from NGA Factors (2008).

Emissions associated with the combustion of fuel include both Scope 1 and Scope 3 emissions. Scope 1 emissions account for the point source onsite combustion of the fuel (within the organisation) and Scope 3 emissions account for extraction and transportation of the fuel (outside the organisation). The emission factors for each fuel are different.

The relevant emission factors for diesel and petrol were used in the calculations (refer NGA 2008, Table 3).

A copy of the calculations used in the assessment is provided in **Annex C**.

Annex C

C. Calculations

GHG EMISSION CALCULATIONS

1	**Baseline Emissions** **(<u>without</u> implementation of Goaf Gas Drainage and Utilisation Project)**		
	NOTE: Assumes all gas is vented to atmosphere without any utilisation for EDL power generation or flaring		
	Average Coal Seam Thickness	3	m
	Plan View Area of Longwall 703	713500	m^2
	Plan View Area of Longwall 704	630000	m^2
	Volume of ROM Coal in Longwall 703	2354550	m^3
	Volume of ROM Coal in Longwall 704	2079000	m^3
	Assumed density of coal	1.50	t/m^3
	Mass of Coal in Longwall 703	3531825	t
	Mass of Coal in Longwall 704	3118500	t
	Total Mass of Coal	6650325	t ROM coal
	Emission Factor for Fugitive Emissions (Gassy Underground Mines [NGA, 2008])	0.305	t CO_2-e/t ROM coal
	Total Baseline GHG Emissions (Scope 1)	**2028349**	**t CO_2-e**
2	**Project Emissions (Construction / Setup / Installation Works)** **(<u>with</u> implimentation of Goaf Gas Drainage and Utilisation Project)**		
2.1	**Diesel Combustion During Construction / Setup / Installation Works**		
	(NOTE: Includes drilling of boreholes, installation of surface goaf extraction pipeline, construction / relocation / installation of extraction plant, and reticulation to underground EDL connection)		
	Fuel type = "Diesel Oil"		
	(refer NGA Factors (2008), p16, Table 4)		
	Total Volume of Fuel Consumed (Q_i)	29.2	kL
	Energy Content Factor (ECi)	38.6	GJ/kL
	Energy Content	1125	GJ
	Scope 1		
	CO_2 Emission Factor (EF_{ijoxec})	69.2	kg CO_2-e / GJ
	CH_4 Emission Factor (EF_{ijoxec})	0.1	kg CO_2-e / GJ
	N_2O Emission Factor (EF_{ijoxec})	0.2	kg CO_2-e / GJ
	Total Emission Factor (EF_{ijoxec})	69.5	kg CO_2-e / GJ
	Total Scope 1 $CO_{2\text{-}e}$ emissions (E_{ij})	**78.2**	**t CO_2-e**
	Scope 3		
	Scope 3 CO_2-e Emission Factor (EF_{ijoxec})	5.3	kg CO_2-e / GJ
	(NGA Factors [2008], page 58,Table 38)		
	Total Scope 3 $CO_{2\text{-}e}$ emissions (E_{ij})	**6.0**	**t CO_2-e**
	Total Diesel Fuel Combustion GHG Emission (Scope 1 + Scope 3)	**84.2**	**t CO_2-e**
2.2	**Petrol Fuel Consumption from Employee Travel**		
	Fuel type = "Gasoline (other than for use as fuel in an aircraft)"		
	(refer NGA Factors (2008), p16, Table 4)		
	Total Volume of Fuel Consumed (Q_i)	2.7	kL
	Energy Content Factor (ECi)	34.2	GJ/kL
	Energy Content	92	GJ
	Scope 1		
	CO_2 Emission Factor (EF_{ijoxec})	66.7	kg CO_2-e / GJ
	CH_4 Emission Factor (EF_{ijoxec})	0.2	kg CO_2-e / GJ
	N_2O Emission Factor (EF_{ijoxec})	0.2	kg CO_2-e / GJ
	Total Emission Factor (EF_{ijoxec})	67.1	kg CO_2-e / GJ
	Total Scope 1 $CO_{2\text{-}e}$ emissions (E_{ij})	**6.2**	**t CO_2-e**
	Scope 3		
	Scope 3 CO_2-e Emission Factor (EF_{ijoxec})	5.3	kg CO_2-e / GJ
	(NGA Factors [2008], page 58,Table 38)		
	Total Scope 3 $CO_{2\text{-}e}$ emissions (E_{ij})	**0.5**	**t CO_2-e**
	Total Petrol Fuel Combustion GHG Emission (Scope 1 + Scope 3)	**6.7**	**t CO_2-e**

2.3	**PROJECT EMISSION TOTALS for Construction / Setup / Installation Works (Scope 1 & Scope 3)**		
	Scope 1	84	t CO_2-e
	Scope 2	NA	t CO_2-e
	Scope 3	6	t CO_2-e
	TOTAL (Scope 1 + Scope 2)	**84**	**t CO_2-e**
	TOTAL (Scope 1 + Scope 2 + Scope 3)	**91**	**t CO_2-e**
3	**Project Emissions (Operational)** **(with implimentation of Goaf Gas Drainage and Utilisation Project)**		
3.1	**Goaf Gas Drainage Emissions**		
	Gas Extraction Data		
	Goaf Extraction Flow Rate	800	L/s
	Total Goaf Extraction Duration	89	weeks
	Total Volume of Gas Extracted via Goaf Bores	43061760	m3
	Seam Gas Composition	86.9	% CH_4
		7.76	% CO_2
		0.56	% O_2
		3.06	% N2
		1.73	% C_2H_6
		0.54	% C_3H_8
		0.28	% C_4H_{10}
		0.19	% H_2
		0.03	% Ar
	Consideration of MVA Dilution of Seam Gas in Goaf Gas		
	MVA Portion of Goaf Gas (ie, air from mine ventilation system)	30	%
	Seam Gas Portion of Goaf Gas (ie, gas from coal seam)	70	%
	Total Effective Volume of Coal Seam Gas Goaf Gas Drainage Air	30143232	m3
	Goaf Drainage Flow Distribution		
	Portion of Gas to EDL	99	%
	Portion of Gas Vented to atmosphere	1	%
	Goaf Gas Drainage Emissions		
	Goaf Gas Emissions from EDL Power Generation (Scope 3)	57748	t CO_2-e
	Goaf Gas Emissions from Venting (Scope 1)	3973	t CO_2-e
	Total Goaf Gas Drainage Emissionss (Scope 1 + Scope 3)	**61721**	**t CO_2-e**
	Baseline Goaf Gas Emissions	397263	t CO_2-e
	(NOTE: Baseline goaf gas emissions have been calculated as the total amount of CO2-e contained in the extracted goaf gas. This number represents the emissions that would occur via the goaf drainage project if all drained gas was vented with no utilisation.)		
	Total Reduction due to EDL Power Generation and/or Flaring of Drained Goaf Gas	**-335543**	**t CO_2-e**
	(calculated as Baseline Goaf Gas Emissions minus Total Goaf Gas Drainage Emissions)		
3.3	**Extraction Plant Power Supply (Diesel Combustion)**		
	Duration of Extraction Operation for Goaf Drainage (as per Section 3.1)	89	Weeks
	Diesel Fuel Consumption per Week (assumes 175 kVA generator)	3500	L/week
	Fuel type = "Diesel Oil"		
	(refer NGA Factors (2008), p16, Table 4)		
	Total Volume of Fuel Consumed (Q_i)	311.5	kL
	Energy Content Factor (ECi)	38.6	GJ/kL
	Energy Content	12024	GJ
	Scope 1		
	CO_2 Emission Factor (EF_{ijoxec})	69.2	kg CO_2-e / GJ
	CH_4 Emission Factor (EF_{ijoxec})	0.1	kg CO_2-e / GJ
	N_2O Emission Factor (EF_{ijoxec})	0.2	kg CO_2-e / GJ
	Total Emission Factor (EF_{ijoxec})	69.5	kg CO_2-e / GJ
	Total Scope 1 CO_{2-e} emissions (E_{ij})	**836**	**t CO_2-e**

	Scope 3		
	Scope 3 CO_2-e Emission Factor (EF_{ijoxec})	5.3	kg CO_2-e / GJ
	(NGA Factors [2008], page 58,Table 38)		
	Total Scope 3 CO_{2-e} emissions (E_{ij})	**64**	**t CO_2-e**
	Total Emissions for Operational Power Supply (Scope 1 + Scope 3)	**899**	**t CO_2-e**
3.5	**PROJECT EMISSION TOTALS for Operation of Goaf Gas Drainage and Utilisation Project (Scope 1 & Scope 3)**		
	Scope 1	4808	t CO_2-e
	Scope 2	N/A	t CO_2-e
	Scope 3	57812	t CO_2-e
	TOTAL (Scope 1 + Scope 2)	**4808**	**t CO_2-e**
	TOTAL (Scope 1 + Scope 2 + Scope 3)	**62620**	**t CO_2-e**
4	**Post-Project Appin Mine MVA (Fugitive Emissions)** **(<u>with</u> implimentation of Goaf Gas Drainage and Utilisation Project)**		
	Baseline Emissions (as calculated in **Section 1**)	2028349	t CO_2-e
	<u>Minus</u> baseline goaf gas emissions (as calculated in **Section 3.1**)	397263	t CO_2-e
	(NOTE: Baseline goaf gas emissions have been calculated as the total amount of CO2-e contained in the extracted goaf gas. This number represents the emissions that <u>would</u> occur via the goaf drainage project if all drained gas was vented with no utilisation.)		
	Total Fugitive Emissions via Appin Mine MVA (Scope 1)	**1631086**	**t CO_2-e**
5	**POST-PROECT EMISSION TOTALS** **(<u>with</u> implimentation of Goaf Gas Drainage and Utilisation Project)**		
	Scope 1	1635894	t CO_2-e
	Scope 2	N/A	t CO_2-e
	Scope 3	57812	t CO_2-e
	TOTAL (Scope 1 + Scope 2)	**1635894**	**t CO_2-e**
	TOTAL (Scope 1 + Scope 2 + Scope 3)	**1693706**	**t CO_2-e**

Pre and Post Project Emissions Summary Table

Operation	Scope 1 Emission Total (kt CO2-e)	Scope 3 Emission Total (kt CO2-e)	TOTAL EMISSIONS (kt CO2-e)	Equivilent Annual Average Emission (kt CO2-e/yr)
Baseline Emissions (ie, without implimentation of Goaf Gas Drainage and Utilisation Project)				
Total Baseline Emissions	2028		2028	1193
Post-Project Emissions (ie, with implimentation of Goaf Gas Drainage and Utilisation Project)				
Project Emissions (Construction / Setup / Installation Works)				
Diesel Combustion During Construction / Setup / Installation Works	0.078	0.006	0.084	0.049
Petrol Fuel Consumption from Employee Travel	0.0062	0.0005	0.0067	0.0039
Project Emissions (Operational)				
Goaf Gas Drainage Emissions	4.0	58.0	62.0	36.5
Extraction Plant Power Supply (Diesel Combustion)	0.8	0.1	0.9	0.5
Post-Project Appin Mine MVA (Fugitive Emissions)	1631.0		1631.0	959.4
Total Post-Project Emissions	1636	58	1694	996

Emission Reduction Summary Table

Operation	Total Emission (kt CO2-e)	Equivilent Annual Average Emission (kt CO2-e/yr)
Baseline Emissions (ie, without implimentation of Goaf Gas Drainage and Utilisation Project) [a]	2028	1193
Post-Project Emissions (ie, with implimentation of Goaf Gas Drainage and Utilisation Project)	1694	996
Total Reduction in Emissions due to Goaf Gas Drainage and Utilisation Project	**334**	**196**