14 Greenhouse Gas Emissions and Climate Change

Section 14 Greenhouse Gas Emissions and Climate Change

14.1 Introduction

This section of the Environmental Impact Statement (EIS) describes the greenhouse gas and climate change legislative framework, the potential impacts of the proposed mining operations, and mitigation measures associated with the Project.

14.2 Greenhouse Gas Emissions

14.2.1 Legislative Framework

14.2.1.1 International Policy

In 1997, the United Nations Framework Convention on Climate Change (UNFCC) produced the Kyoto Protocol aimed at limiting the greenhouse gas (GHG) emissions of countries that ratified the protocol (United Nations, 1997). The Kyoto Protocol entered into force in 2005, and was designed to work by setting limits to individual mandatory GHG emission targets using the ratifying country's 1990 GHG emissions as their baseline.

The Kyoto Protocol sets out three flexibility mechanisms to allow GHG targets to be met:

- The Clean Development Mechanism;
- Joint Implementation; and
- International Emissions Trading.

These three mechanisms effectively allow GHG reductions to be made at the point where the marginal cost of that reduction is lower. An industrialised country sponsoring a GHG reduction project in a developing country can claim that reduction towards its Kyoto Protocol target and those GHG reductions can be traded.

Australia ratified the Kyoto Protocol in December 2007 and has committed to meeting its Kyoto Protocol target of 108% of 1990 emissions by 2012.

14.2.1.2 Australian Policy

The Australian policy on climate change was released in July 2007 and is managed by the Commonwealth Government Department of Climate Change and Energy Efficiency (DCCEE). The policy sets out the Commonwealth Government's focus on reducing GHG emissions, encouraging the development of low emissions and emission reduction technology climate change adaptation, and setting national policies and response to climate change within a global context.

On 24 February 2011, the Prime Minister Julia Gillard announced a climate change framework outlining the broad architecture for a carbon price mechanism, which has been considered by the Multi-Party Climate Change Committee (DCCEE, 2011). The proposed mechanism has been agreed to by the Government and Greens members of the Committee.

The proposal focuses on the high level architecture, sectoral coverage, international linking arrangements and potential progression to emissions trading. It outlines a two-stage plan for a carbon price mechanism commencing in July 2012 with a fixed price period for three to five years before transition to an emissions trading scheme.

Further detailed discussions are required in relation to a starting carbon price for the mechanism; assistance arrangements for households, communities and industry; and support for low emissions technology and innovation. The architecture also allows for consideration of other design options such as phased coverage and an intensity-based allocation scheme for the electricity sector.

Definitive details of the proposal are yet to be determined, and the legislation is subject to a majority agreement in both houses of Parliament, which will be sought later this year. Therefore, it is not yet clear how this proposal might impact the Kevin's Corner Project.

Garnaut Review

The Commonwealth Government commissioned the Garnaut Climate Change Review (Garnaut Review) as an independent study to examine the impacts, challenges and opportunities of climate change for Australia. The Garnaut Review's final report was released on 30 September 2008 (Garnaut, 2008). The Garnaut Review considered the potential impacts that climate change will have on Australia's environment and economy, and proposed medium to long-term policies and policy frameworks to improve the prospects for sustainable prosperity.

National Greenhouse and Energy Reporting Act 2007 (NGER Act)

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

From 1 July 2008, corporations have been required to register and report if:

- They control facilities that emit 25 kilotonnes or more of GHG (CO_2 equivalent), or produce/consume 100 terajoules or more of energy; or
- Their corporate group emits 125 kilotonnes or more GHG (CO_2 equivalent), or produces/consumes 500 terajoules or more of energy.

Energy Efficiency Opportunities (EEO)

The Commonwealth Government's Energy Efficiency Opportunities (EEO) program came into effect in July 2006, and mandates large energy users (over 0.5 petajoules [PJ] of energy consumption per year) to participate in the program. The objective of this program is to drive ongoing improvements in energy consumption amongst large users. Businesses are required to identify, evaluate and report publicly on cost-effective energy saving opportunities.

The EEO program is designed to result in:

- Improved identification and uptake of cost-effective energy efficiency opportunities;
- Improved productivity and reduced GHG emissions; and
- Greater scrutiny of energy use by large energy consumers.

The EEO program will be incorporated into the National Framework for Energy Efficiency.

As the sole Proponent of the Project, and a large energy user, the Proponent is a mandatory participant, and triggers the reporting requirements under the EEO program. Consequently, the minimum requirements of the scheme will need to be met by the Project.

As the EEO program's Assessment Framework takes a whole-of-business approach to assessing energy use and energy saving opportunities, the framework involves corporations looking at the many factors influencing energy use. These factors include leadership, management and policy; the accuracy and quality of data and analysis; the skills and perspectives of a wide range of people; decision making; and communication outcomes. Participants are expected to meet minimum requirements in each of these areas.

14.2.1.3 State Policy Initiatives

In October 2007, the Queensland Government created the Office of Climate Change in order to lead an effective climate change response. The strategy adopted is ClimateSmart 2050 (Queensland Government, 2007).

ClimateSmart 2050 aims at reducing GHG emissions by 60% from 2000 levels by 2050, in line with the national target, by building initiatives into the Queensland Energy Policy (Queensland Government, 2000). It includes the introduction of:

- Smart Energy Savings program, which targets large energy users and requires them to undertake energy efficiency audits and implement energy savings measures that have a three-year or less payback period;
- Queensland Future Growth Fund for development of clean coal technologies; and
- Changes to the Queensland Gas Scheme, which will oblige major industries to source 18% of all power form Queensland-based gas-fired generation.

ClimateQ: toward a greener Queensland presents the next phase in Queensland's response to the challenge of climate change. The revised strategy presents investments and policies to ensure Queensland remains at the forefront of the national climate change response. One of the key policies in this strategy is that the approval of new coal-fired power stations will be conditional on meeting criteria relating to GHG emissions. These conditions include no approval for a new coal-fired power station unless:

- It uses world's best practice low emission technology in order to achieve the lower possible levels of emissions; and
- It is carbon capture and storage (CCS) ready and will retrofit that technology within five years of CCS being proven on a commercial scale.

14.2.2 Inventory Methodology

14.2.2.1 Accounting and Reporting Principles

This inventory follows the accounting and reporting principles detailed in the National Greenhouse and Energy Reporting System Measurement Technical Guidelines (Technical Guideline), June 2010 (DCCEE, 2010a). The main principles of the Technical Guidelines (DCCEE, 2010a) are described below:

- Transparency – emission estimates must be documented and verifiable;
- Comparability – emission estimates using a particular method and produced by a registered corporation in an industry sector must be comparable with emissions estimates produced by similar corporations in that industry sector using the same method and consistent with the emission estimates published by the DCCEE in the National Greenhouse Accounts;
- Accuracy – having regard to the availability of reasonable resources by a registered corporation and the requirements of the guideline, uncertainties in emission estimates must be minimised and any estimates must neither be over nor under estimates of the true values at a 95% confidence level; and
- Completeness – all identifiable emission sources within the energy, industrial process and waste sectors as identified by the National Inventory Report must be accounted for.

14.2.2.2 Inventory Boundaries

In preparing a GHG Assessment, there are two forms of boundaries to be specified: organisational boundaries and operational boundaries.

The Proponent is the sole owner of the Project. The organisational boundary is delineated by the physical mine area comprising Mining Lease Application (MLA) 70425, and includes all the GHG emissions controlled or influenced by the Project. The GHG emissions that are outside the control or influence of the Project, such as the use of the coal as a thermal product, lie outside this boundary.

The operational boundary for the GHG assessment includes both direct and indirect emissions from the Project.

The Technical Guidelines further define direct and indirect emissions through the concept of emission scope as follows:

- Scope 1: Direct GHG emissions. Emissions released from a facility as a direct result of the activities of the facility. For example:
  - Emissions from combustion in owned or controlled boilers, furnaces, vehicles, etc.;
  - Emissions from on-site power generators; and
  - Coal Seam Gas (CSG) released to atmosphere.
- Scope 2: Indirect GHG emissions. Scope 2 emissions are activities that generate electricity, heating, cooling or steam that is consumed by the facility but do not form part of the facility. They occur principally at electricity generators as a result of electricity consumption at another facility. They are recorded principally as a measure of what might happen to national emissions as a result of the consumption of electricity from facilities.

14.2.2.3 Calculation Approach

Data from the following sources have been utilised in the formation of the inventory:

- Activity data used to assess Scope 1 fugitive emissions (extraction of coal) are based on information provided by the Proponent, and are broken down into annual consumption from 2014 to 2042. These data include:

— Estimated run of mine (ROM) coal for the mine area as a whole for each year of operation of the mine, separated into open cut and underground coal mined;
— Estimated product coal (tonnes) for each year of operation of the mine; and
— Coal seam gas analysis data (Dallas, 2010)

- Activity data used to assess Scope 1 emissions from diesel usage are based on information provided by the Proponent, and are broken down into annual consumption in litres from 2012 to 2043. For the purposes of this assessment, equipment has been divided into stationary and transport usage.
- Activity data used to assess Scope 2 emissions from electricity usage are based on information provided by the Proponent, and are broken down into annual consumption from 2014 to 2043. Assumptions made when using these data included:

— Years 2012 – 2014 (inclusive) anticipated for construction, 2014 onwards anticipated for operation.

Emission Factors

Direct measurement of GHG at the emission source provides the most accurate and precise assessment of GHG emissions. While preliminary data are available from direct measurement for this proposed coal mine, it was decided this information was not complete enough to extrapolate the results over the mine. This is not unusual as direct measurement of GHG at the source is not always feasible or achievable especially for assessing new mining developments. In these situations it is usual to adopt the Method 1 emission factors from the National Greenhouse Accounts (NGA) Factors workbook (DCCEE, 2010c). For the purposes of this assessment, emission factors have been adopted from DCCEE (2010c), with emission factors for non-gassy mines being adopted for determining fugitive emissions from underground coal mining (open-cut emission factors were adopted for the open-cut mining component of the project). Borehole gas analysis data summated within Dallas (2010) indicates that the Kevin's Corner Project can be classified as a non-gassy mine[1].

The emission factors used in this report are presented in Table 14-1.

[1] DCCEE (2010a) defines non-gassy mine as "an underground mine that has less than 0.1% methane in the mine's return ventilation".

Table 14-1: Emission Factors used in the formation of the Kevin's Corner Coal Project (Mine) greenhouse gas (GHG) Inventory

Emission Source	Units	Emission Factors			Energy Content	NGA Factors Reference
		CO_2	CH_4	NO_2		
Scope 1 Emissions						
Extraction of Coal (Fugitive Emissions)[1]- Underground Mining	T CO_2-e/t ROM	-	0.008	-	-	Section 2.4.1.1
Extraction of Coal (Fugitive Emissions)- Open Cut Mining	T CO_2-e/t ROM	-	0.017	-	-	Section 2.4.1.2
Diesel (Stationary Energy)	T CO_2-e/kL fuel	69.2	0.1	0.2	38.6	Section 2.11
Diesel (Transport Energy)	T CO_2-e/kL fuel	69.2	0.2	0.5	38.6	Section 2.21
Explosives (Ammonium Nitrate Fuel Oil)	T CO_2-e/kL fuel	72.9	0.03	0.2	39.7	Section 2.31
Scope 2 Emissions						
Electricity	T CO_2-e/kWh	0.89			-	Section 2.3

Notes: [1] Emission factor for non-gassy mine adopted based on data provided in Dallas (2010).

Materiality

Materiality is a concept used in accounting and auditing to minimise time spent verifying amounts and figures that do not impact a company's accounts or inventory in a material way. The exact materiality threshold used in GHG emissions accounting and auditing is subjective and dependent on the context of the site and the features of the inventory. Depending on the context, the materiality threshold can be expressed as a percentage of a company's total inventory, a specific amount of GHG emissions, or a combination of both.

All emissions that are found within the boundary are included in the inventory unless they are excluded on materiality grounds. Information is considered to be material if, by its inclusion or exclusion, it can be seen to influence any decisions or actions taken by users. A material discrepancy is an error (for example, from an oversight, omission or miscalculation) that results in a reported quantity or statement being significantly different from the true value or meaning.

Within this report, emissions are assumed to be immaterial if they are likely to account for less than 5% of the overall emissions profile. This materiality threshold has been chosen on the basis of the author's experience of coal mine GHG inventories and work reviewed in other coal mine EIS's. The following emissions are not included on the inventory on the basis of materiality:

- Consumption of unleaded fuel (ULP) or Liquefied Petroleum Gas (LPG) in site vehicles. Most site vehicles run on diesel fuel, which is included in the inventory. Only small vehicles such as cars belonging to site personnel will consume unleaded fuel and are typically immaterial; and
- The inventory does not consider emissions arising from land use, land use change and forestry, such as rehabilitation and clearing.

Aggregation

Aggregation refers to the combining of several inventories, typically of different sites or operations, into an overall inventory. This report is specific to the Project and does not contain an aggregated inventory of all the Proponent's GHG emissions.

Uncertainty Analysis

A measure of the uncertainty for Scope 1 emissions within the inventory is a standard part of a GHG inventory as indicated by the Technical Guidelines (DCCEE, 2010a). Uncertainties associated with the GHG inventory are either related to scientific uncertainty or estimation uncertainty.

Analysing and quantifying scientific uncertainty is extremely problematic as it often involves, for example, estimating uncertainty in the global warming potential values; and as a consequence, an estimate of scientific uncertainty is beyond the capacity of this inventory.

Estimation uncertainty can be classified further into two types: model uncertainty and parameter uncertainty. Model uncertainty refers to the uncertainty associated with mathematical equations used to calculate the emissions. This is also beyond the scope of the inventory.

Parameter uncertainties within this inventory can be divided into two parts: uncertainty relating to activity data and uncertainty relating to emission factors. Activity uncertainties relate to measured quantities, such as production, consumption, monitored data, etc. Emission factor uncertainty considers the conversion from measured activities to GHG emissions.

Fugitive Emissions

Under the Technical Guidelines (DCCEE, 2010a), an aggregated (combined) uncertainty level of ± 50% has been given for open-cut and underground mines. This includes the uncertainty level for the emission factor, energy content factor, and the activity data.

Diesel Combustion

Following the process outlined in the Technical Guidelines (DCCEE, 2010a), an uncertainty level for diesel is determined by a combination of uncertainties associated with the energy content factor, CO_2 emission factor and the quantity of fuel.

The Technical Guidelines (DCCEE, 2010a) provide a standard uncertainty for diesel for the energy content factor and emission factor. For the estimation of the quantity of fuel, the Technical Guidelines (DCCEE, 2010a) provide an uncertainty level based on the method used to make the estimation. The levels of uncertainty for the method of estimation of the quantity of fuel have been outlined in Table 14-2. For this assessment, Criteria BBB has been adopted.

Table 14-2: Level of Uncertainty for the method of estimation of the quantity of fuel

Criterion Letter	Criterion	Uncertainty Level (%)
A	The amount of the fuel delivered for the facility during the year as evidenced by invoices or delivery records issued by the vendor of the fuel.	1.5
AA	Indirect measurement at the point of consumption, based on the amount of fuel delivered for the facility and adjusted for changes in stock.	1.5
AAA	Direct measurement at the point of consumption, based on the amount of fuel combusted as estimated by measurement equipment that complies with specified standards.	1.5
BBB	Simplified measurement of consumption.	7.5

Table 14-3 outlines the uncertainties and how they have been derived.

Table 14-3: Uncertainties for diesel

Parameter	Percentage Uncertainty (%)	Source
Energy Content Factor	2	As specified for Diesel in the Technical Guidelines
Emission Factor	2	As specified for Diesel in the Technical Guidelines
Quantity of Fuel Combusted	7.5	Criteria BBB per Table 14-2

Per Section 8.11 (1) of the Technical Guidelines (DCCEE, 2010a), the aggregated uncertainty for diesel is calculated by:

Equation 1: $$D = \pm\sqrt{A^2 + B^2 + C^2}$$

where:

D is the aggregated percentage uncertainty for the emission source;

A is the uncertainty associated with the emissions factor for the source expressed as a percentage;

B is the uncertainty associated with the energy content factor for the source expressed as a percentage; and

C is the uncertainty associated with the activity data for the source expressed as a percentage.

The technique used for aggregating the uncertainty is known as the first order error propagation. There are four key assumptions that are made when this technique is used and should be considered.

- The error in each parameter is normally distributed;
- There are no biases in the estimator function (i.e. the estimated value is the mean value);
- The estimated parameters are uncorrelated; and
- Individual uncertainties in each parameter must be less than 60% of the mean.

It is considered reasonable to assume that the above conditions are satisfied and that the uncertainty calculation will be reasonable.

Using the methodology detailed in the Technical Guidelines (DCCEE, 2010a), an aggregated uncertainty level of ± 8% has been calculated for diesel. This includes the uncertainty level for the emission factor, energy content factor, and the activity data.

14.2.3 Calculated Emissions

14.2.3.1 Scope 1 and Scope 2 Emission Summary

The GHG Scope 1 and Scope 2 emission sources from the Project that are included in this inventory are:

- Fugitive emissions of CSG from the mining of coal (Scope 1);
- Diesel combustion in vehicles (Scope 1);
- Diesel combustion for stationary energy (i.e. pumps) (Scope 1);

- Diesel combustion for explosives (Scope 1); and
- Electricity consumption (Scope 2).

The Scope 1 and Scope 2 emissions for the Project are summarised in Table 14-4. The average annual emissions from the Project are presented, as well as the total GHG emissions over the 30-year Life of Mine (LOM).

Table 14-4: GHG Emissions for the Project

Scope	Source	Minimum Emissions (t CO_2-e / yr)	Maximum Emissions (t CO_2-e / yr)	Average Emissions (t CO_2-e / yr)	Life of Mine Emissions (t CO_2-e / yr)	Uncertainty (±%)
1	Fugitive emissions	75,360	320,468	279,676	7,830,936	50
1	Diesel combustion (transport)	19,804	55,238	33,506	971,679	8
1	Diesel combustion (stationary)	1,660	15,888	13,111	380,222	8
1	Explosives- Ammonium Nitrate Fuel Oil (ANFO)	0	57,030	3,824	110,891	Not applicable
	Annual Scope 1[1]	30,462	389,253	320,473	9,293,728	
2	Purchased Electricity	525,399	2,024,881	1,699,164	49,275,743	Not Applicable
	Annual Scopes 1 and 2[1]	637,074	2,392,332	2,019,637	58,569,471	

[1] This row indicates the minimum, maximum, average and life of mine emissions of all the totalled Scope 1 emissions and hence will not equal the total of the Scope 1 emissions included in this table.
[2] This row indicates the minimum, maximum, average and life of mine emissions of all the totalled Scopes 1 and 2 emissions and hence will not equal the total of the Scopes 1 and 2 emissions included in this table.

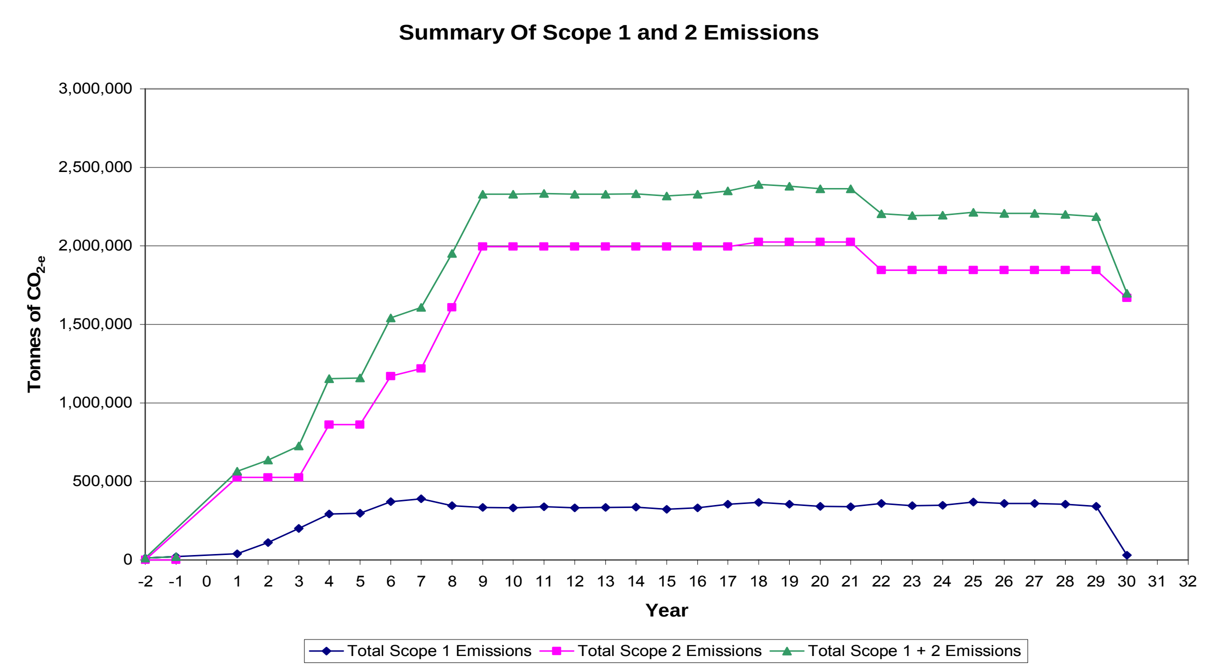
The GHG emissions presented are based on current knowledge about the mine operations, diesel and electricity consumption. However, there is the potential for them to change over the life of the mine due to technology improvements. For fugitive emissions, as discussed in Section 14.2.2.3, preliminary borehole data for the Project are available in the Dallas (2010) report. In addition, results from testing undertaken on the lease next to the Project (extracting from the same seams of coal) are also available. While the Project data were considered insufficient to adequately quantify the fugitive emissions from this mine, the indication was that the fugitive emissions from the Project are likely to be approximately one-third of the results presented in this section. This is substantiated by the Alpha Coal Project testing, which indicates that the seams produce substantially less GHG from fugitive emissions than is predicted using the NGA factors used in this report. Further testing is being undertaken, with results expected to be available for the Supplementary phase of the EIS process.

Figure 14-1 shows the estimated GHG emissions for the Scope 1 and Scope 2 emissions throughout the life of the Project.

Analysis of the annual GHG inventory for all Scope 1 and Scope 2 emissions shows the GHG emissions are forecast to increase up to operational year 9, where they are forecast to remain relatively steady with small fluctuations. The largest GHG emissions are predicted to occur in operational year 18, where a slight peak in Figure 14-1 is apparent. This peak corresponds with an estimated peak production year (in terms of run of mine coal produced), and an increase in electricity usage. Scope 2 emissions far exceed Scope 1 emissions throughout the life of the mine. This can be attributable to the determination of fugitive emissions for coal production. The mine exhibits a very low gas content, which is apparent in the gas analysis data, which allows for the underground mining to be classified as non gassy.

The Project will be obliged to report under the NGER Act given that emissions for the Project's Scope 1 and Scope 2 emissions will exceed the 25,000 tonne CO_2-e threshold.

Figure 14-1: Total of Scope 1 and Scope 2 GHG emissions (tonnes CO2-e)



14.2.3.2 Performance Measures

The performance of the GHG emissions efficiency can be measured as emissions intensity. Emissions intensity is defined as tonnes CO_2-e per tonne of product coal.

The emissions intensity of the Project based on Scope 1 and Scope 2 emissions ranges from 0.06 to 0.13 tonnes CO_2-e per tonne of product coal once operations are in full production, averaging 0.09 tonnes CO_2-e per tonne of product coal. The construction period prior to the operational phase of the Project is not included in this comparison as no coal is produced and therefore no performance assessment can be made.

14.2.4 Emissions Comparison

14.2.4.1 Australian Emissions

The National GHG Inventory (DCCEE, 2010b) is the latest available national account of Australia's GHG emissions. The National GHG Inventory (DCCEE, 2010b) has been prepared in accordance with the Revised 1996 and 2006 Intergovernmental Panel on Climate Change (IPCC) Objectives for National GHG inventories (IPCC, 2007). The IPCC guidance defines six sectors for reporting GHG emissions; these include:

1. Energy Sector (including coal mining);
2. Industrial Processes;
3. Agriculture;
4. Waste;
5. Other; and
6. Land Use, Land Use Change and Forestry.

Australia's net GHG emissions across all sectors total 576 million tonnes (Mt) CO_2-e in 2008, with the mining sector emitting 71.3 Mt CO_2-e.

Table 14-5 shows total annual Scope 1 and Scope 2 emissions at different stages of the life of the mine as a percentage of Australian total and mining sector emissions taken from the National GHG Inventory 2008 (DCCEE, 2008).

Table 14-5: Comparison of Australia and Project GHG emissions

Year of Operation	Percentage of Australia Mining Sector (%)	Percentage of Australian Total (%)
Minimum GHG Emissions	0.89	0.11
Peak GHG Emissions	3.36	0.42
Average GHG Emissions	2.83	0.35

14.2.4.2 Queensland Emissions

Table 14-6 shows total annual Scope 1 and Scope 2 emissions at different stages of the life of the mine as a percentage of Queensland total (160.3 Mt) and Queensland mining sector (15.9 Mt) emissions taken from the National GHG Inventory 2008 (DCCEE, 2008).

Table 14-6: Comparison of Queensland and Project GHG emissions

Year of Operation	Percentage of Queensland Mining Sector (%)	Percentage of Queensland Total (%)
Minimum GHG Emissions	4.01	0.40
Peak GHG Emissions	15.05	1.49
Average GHG Emissions	12.70	1.26

When viewed in an Australian or Queensland context the Scope 1 and Scope 2 emissions from the Project are considered materially relevant given the Project emissions are 15.05% of the 2008 Queensland mining sector at the peak emission rate.

The Queensland Government has proposed to reduce GHG emissions by 60% by 2050 based on 2000 levels in line with the national target. This equates to a reduction of approximately 98 Mt CO_2-e.

Average Scope 1 and Scope 2 GHG emissions from the Project will be 2.0 Mt CO_2-e or 1.26% of the state inventory.

14.2.5 Abatement

The following aspects of the Project Description assist in reducing GHG emissions:

- The use of conveyors maximises materials transport efficiency, minimising the use of diesel.

- Extending the rail line to the Project site increases efficiency of transport of bulk and potentially freight materials.
- Placement of the accommodation village on the site reduces the need for transport of personnel to and from the site and accommodation.
- The use of electric-powered mining equipment enables opportunities to use different energy sources in the future as they become economically competitive.
- The high proportion of underground operations assists by expending energy only on the mining of the coal itself, and less so for the blasting and relocation of overburden materials.
- The mine is incorporating energy efficiency via direct and indirect means into the mine infrastructure and operating methods.

The objectives of the energy conservation and GHG management plan are to:

- Reduce GHG emissions associated with the Project and all relevant emissions sources;
- Incorporate energy efficiency initiatives into Project design, engineering, construction and operation;
- Integrate GHG management and energy efficiency initiatives into business decision-making at all stages of the Project; and
- Provide consistent and accurate reports on GHG emission levels in compliance with relevant legislation.

The following measures will be implemented:

- Material movement will be efficient by minimising rehandling and utilisation of underground methods (i.e. limited waste fragmentation, handling and elevation);
- On-site bulk materials transport (i.e. coal and potentially overburden) will be via conveyor wherever practicable rather than by truck;
- Transport footprint will be minimised by operating shuttle services for project personnel;
- Bulk materials will be delivered to site by rail freight rather than by road, depending on the configuration of Abbott Point port operations;
- Plant and equipment:-
  - — Energy efficiency ratings will be investigated and higher ratings will indicate the preferred option;
  - — Plant and equipment will be maintained in a proper condition;
  - — Plant and equipment will be operated in a proper manner; and
  - — Roads will be maintained in good order to allow mobile fleet to operate fuel efficiently.
- Blasting activities will be optimised to minimise double handling;
- The use of remote operations centres;
- Supporting infrastructure will aim to be energy efficient using technology to minimise latent energy demand. This includes the use of smart controllers to turn off air conditioning systems when not in use and to prefabricate and prepare Project inputs off-site with greater efficiency and less waste;

- A GHG inventory will be maintained from construction onwards with reporting requirements to the Greenhouse and Energy Data Officer filed annually (per the NGER legislation).

Analysis of CSG data to date indicates very low gas content (in terms of GHG footprint). Subsequently Scope 1 emissions have shown to be lower than Scope 2 emissions. Dallas (2010) suggests that current gas analysis data show that methane content is too low (i.e. below the lower feasible operating parameter) for there to be a requirement for a methane destruction unit (i.e. flare).

14.3 Climate Change Impact Assessment

In 2007, Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO) released the technical report *Climate Change in Australia* (CSIRO, 2007), which provides the most up-to-date assessment of observed Australian climate changes and causes and projections for 2030 to 2070. The report is based upon international climate change research including the latest IPCC (2007) conclusions, and builds on a large body of climate research that has been undertaken for the Australian region in recent years.

The purpose of this report was to provide an up-to-date assessment of observed climate change over Australia, the likely causes, global climate change projections, regional projections for Australia, and guidance on using projections in risk assessments.

In 2008, the Queensland Environmental Protection Agency (EPA) (now Department of Environment and Resource Management [DERM]) released the technical report *Climate Change in Queensland; what the science is telling us* (Queensland Government, 2008). This report elaborates on the findings of the CSIRO report specifically for Queensland.

The following section presents the Climate Change Impact Assessment for the Project using the climate change predictions made in the CSIRO (2007) report and Queensland Government (2008) report, assesses the potential impact on the Project, and provides risk management measures, where appropriate.

14.3.1 Predicted Impacts

14.3.1.1 Model Limitations

It is important to understand the limitations of a model when interpreting the results. Uncertainties in climate change projections arise due to inaccuracies in the models, differences between models employed and the uncertainties in actual future emissions. This has led to the need to test a wide range of scenarios. Projections for the later decades of the 21st Century are more uncertain as it is harder to predict global GHG emission rates that far into the future. Projections for 2030 show little variation between different emissions scenarios, as these near-term changes in climate are strongly affected by GHG that have already been emitted. For this reason, the projections for 2030 are usually based on a mid-range emissions scenario, whereas for 2070, low and high emissions scenarios are presented.

It is noted the Project is likely to conclude in 30 to 40 years, and as such the extremes of climate change presented for 2070 will not affect the Project. The 2070 predictions have been included in order to indicate the trend of the change in climate over the life of the Project.

To provide the most accurate results possible, the 50th percentile has been presented.

Projections are relative to the period 1980-1999 (referred to as the 1990 baseline for convenience).

Results for three areas of Queensland have been extrapolated from the model; this includes Brisbane, Cairns and St George. The results for St George have been adopted as representative of the Project, as it best represents an inland area of Queensland.

14.3.1.2 Predicted Impacts

The following sections summarise the likely effects of climate change in the vicinity of the Project in terms of temperature, rainfall, potential evaporation, wind speed, relative humidity and solar radiation.

Temperature

As can be seen in Table 14-7, temperatures are predicted to trend upwards from the 1990 baseline.

Table 14-7: Temperature impacts of climate change in inland areas of Queensland

Variable	Season	2030 Emissions Scenario	2070 Low Emissions Scenario	2070 High Emissions Scenario
Temperature (ºC)	Annual	1.1	1.8	3.6
	Summer	1.1	1.9	3.6
	Autumn	1.1	1.8	3.5
	Winter	1	1.7	3.3
	Spring	1.2	2	3.9

Given that mine operations are planned to commence in 2013 and close in 2042, it is reasonable to expect an annual temperature increase in the proximity of 1ºC over the life of the mine. Seasons relative to each other will remain fairly consistent.

Rainfall, Evaporation, Relative Humidity and Solar Radiation

Rainfall is predicted to trend downward, evaporation upward, and the relative humidity overall to trend downward, relative to the 1990 baseline. Solar radiation is predicted to trend upward relative to the 1990 baseline. The relevant trend data are presented in Table 14-8.

Table 14-8: Rainfall, evaporation, relative humidity and solar radiation impacts of climate change in inland areas of Queensland

Variable	Season	2030 Emissions Scenario	2070 Low Emissions Scenario	2070 High Emissions Scenario
Rainfall (%)	Annual	-3	-5	-10
	Summer	-1	-1	-3
	Autumn	-3	-6	-11
	Winter	-6	-9	-17
	Spring	-6	-10	-18
Potential Evaporation (%)	Annual	3	5	9
	Summer	3	5	9
	Autumn	3	6	11
	Winter	4	7	13
	Spring	2	4	7
Relative humidity (%)	Annual	-0.5	-0.8	-1.6
Solar Radiation (%)	Annual	0.2	0.3	0.7

There is a greater uncertainty with rainfall projections than with temperature projections. This is because there is a direct relationship between GHG concentrations and temperature, whereas rainfall depends on what happens to general atmospheric circulation. For projections of rainfall, not all climate models agree on whether it is likely to increase or decrease.

An additional concern is the potential for changes in the frequency of El Niño events, as these have a major influence on Queensland's rainfall. Increased intensity of tropical cyclones is likely, but total numbers of cyclones may decrease. The number of tropical cyclones is related to the global El Niño/La Niña-Southern Oscillation (ENSO) phenomenon, so the impact of climate change on ENSO will also affect the number of tropical cyclones in the Queensland region.

Current projections indicate winter and spring rainfall is likely to decrease in central and southern areas of Queensland, but changes in summer and autumn rainfall are less certain. Extreme daily rainfall is expected to be less affected by the projected drying tendency and may increase, particularly in summer and autumn.

Wind Speed

Wind speed is predicted to trend upwards from the 1990 baseline, as shown in Table 14-9.

Table 14-9: Wind speed impacts of climate change in inland areas of Queensland

Variable	Season	2030 Emissions Scenario	2070 Low Emissions Scenario	2070 High Emissions Scenario
Wind Speed (%)	Annual	2	3	5
	Summer	2	4	8
	Autumn	1	1	3
	Winter	0	0	0
	Spring	4	6	11

Over the life of the Project, annual wind speeds are predicted to increase by 1 to 2%; however, these increases will not be realised consistently over the year. Spring winds are predicted to increase most, with summer winds also to increase. Winter wind speeds are not predicted to change.

Summary

Climate in inland areas of Queensland is predicted to change over the life of the Project (CSIRO, 2007). Annually, temperatures are predicted to increase, and rainfall decrease. Evaporation is predicted to increase, as is wind speed. This would likely result in a drier, windier landscape that has fewer cyclone events (a major influence on Queensland's rainfall), but the cyclone events that do occur are likely to be more intense and possibly destructive.

Given the predicted decline in rainfall and increased evaporation, soil moisture and availability and quality of water are predicted to be affected.

Temperatures are predicted to increase by 1ºC, rainfall is predicted to decrease from 2% to 3%, and wind speeds are predicted to increase on the order of 1% during the 30-year Project life.

14.3.2 Risk Assessment

14.3.2.1 Methodology

The following semi-quantitative risk assessment procedure was used to evaluate the risks as a result of the various potential climate change impacts on mining operations. This approach is consistent with the Australian Standards/New Zealand Standards (AS/NZS) ISO 31000:2009 for Risk Management. The key steps in undertaking the risk assessment involved:

- Identification of the potential climatic impacts on mining operations;
- Analysis of the risks in terms of consequence and likelihood; and
- Evaluation of risks, including risk ranking to identify priorities for their management.

The measures used to assign levels of likelihood are presented in Table 14-10.

Table 14-10: Measures of likelihood

Level	Descriptor	Description
1	Rare	Occurs only in exceptional circumstances
2	Unlikely	Could occur but not expected
3	Possible	Could occur
4	Likely	Will probably occur in most circumstances
5	Almost Certain	Is expected to occur in most circumstances

The measures used to assist in the process of assigning levels of consequence are presented in Table 14-11.

Table 14-11: Measures of consequence

Level	Descriptor	Environmental Impact	Project Functionality	Financial Impact (per event or per year)
1	Insignificant	Consequence measured in weeks	No loss of use	<$50,000
2	Minor	Consequence <12 months	Short term loss of use (all/part) <1 week	$50,000 to $500,000
3	Moderate	Consequence 1-2 years	Loss of use (all/part) 1 week to 1 month	$500,000 to $1 million
4	Major	Consequence 2-5 years	Loss of use (all/part) 1 month to 1 year	$1 million to $10 million
5	Catastrophic	Consequence >5 years	Loss of use (all/part) >1 year	>$10 million

The risk assessment matrix in Table 14-12 was used to determine the level of risk based on likelihood and consequence scores. Scenarios with a combined score of 20 or greater are considered to pose an extreme level of risk. Scenarios with a combined score of between 10 and 16 are considered to pose a high level of risk. Scenarios with a combined score of between 5 and 9 are considered to pose a medium level of risk. Scenarios with a combined score of less than 5 are considered to pose a low level of risk.

Table 14-12: Risk Matrix (Commonwealth Government, 2006)

Likelihood	Consequence				
	1 (Insignificant)	2 (Minor)	3 (Moderate)	4 (Major)	5 (Catastrophic)
5 (Almost Certain)	5	10	15	20	25
4 (Likely)	4	8	12	16	20
3 (Moderate)	3	6	9	12	15
2 (Unlikely)	2	4	6	8	10
1 (Rare)	1	2	3	4	5

14.3.2.2 Results

The risks scenarios have been identified on the basis of the EIS team's experience of mining operations, together with consultation with mining specialists. The results of the risk assessment are presented in Table 14-13.

Table 14-13: Risk assessment of the potential impacts of climate change on the Project

Risk Scenario	Likelihood	Consequence	Risk
Increased flood risk due to increased rainfall intensity.	Moderate (3)	Moderate (3)	Medium (9)
Reduced process water availability due to decreased rainfall and increased evaporation.	Moderate (3)	Minor (2)	Medium (6)
Decrease in soil moisture, increased winds and reduced availability of water, which increases generation of dust and reduces ability to manage dust.	Likely (4)	Minor (2)	Medium (8)
Increased maintenance costs for infrastructure due to more severe storm / cyclone events.	Moderate (3)	Minor (2)	Medium (6)
Unsuccessful rehabilitation planting due to reduced rainfall and more severe storm events.	Moderate (3)	Minor (2)	Medium (6)
Failure/overtopping of out-of-pit tailings storage facility	Rare (1)	Major (4)	Low (4)
Increased slope failure due to decreased soil moisture and increased rainfall intensity.	Unlikely (2)	Minor (2)	Low (4)
Health impacts on mine site staff from increased temperatures (e.g. heat stress).	Unlikely (2)	Minor (2)	Low (4)
Increased soil erosion due to decrease in soil moisture and increased rainfall intensity (including access tracks).	Moderate (3)	Insignificant (1)	Low (3)
Increased bushfire events due to increased temperatures and evaporation potential.	Moderate (3)	Insignificant (1)	Low (3)
Decrease in efficiency of equipment due to increased temperature resulting in increased operation costs.	Rare (1)	Moderate (3)	Low (3)
Community/workforce isolation due to higher risks of flooding events.	Rare (1)	Minor (2)	Low (2)

14.3.3 Risk Management Measures

The following risk management measures will be adopted by the Proponent in the development of the Project to address the High and Medium risk scenarios.

High Risk Impacts

- Increased flood risk
  - — Apply appropriate risk assessment methods in design of storage dams, levees and diversion channels.
  - — Protect the mine workings and infrastructure from floodwater inundation 3,000-year Average Recurrence Interval (ARI) event.

Medium Risk Impacts

- Reduced process water availability:
  - — Use the minimum volume of water necessary in the process circuit;
  - — Recycle waters in the process circuit or for other uses, such as dust suppression, as much as possible; and
  - — Segregate water by quality or source.
- Increased dust generation:
  - — Limit the extent of site disturbance; and

- — Undertake rehabilitation progressively, including earthworks, drainage and revegetation.
- Unsuccessful rehabilitation planting:
  - — Monitor rehabilitated areas on a regular basis to ensure that original objectives are achieved. Monitoring will include regular inspections for soil erosion, rehabilitation success, weed infestation, and integrity of water diversion drains, waterways and sediment control structures.
- Increased maintenance costs for infrastructure:
  - — Regularly maintain and service all equipment per the technical specifications.