proposed

Mt Arthur
UNDERGROUND PROJECT

Appendix 13

Greenhouse Gas Assessment

SCOPE 1, 2 AND 3 ENERGY AND GREENHOUSE ASSESSMENT

FOR

Mt Arthur Coal

UNDERGROUND PROJECT

BY

SEE SUSTAINABILITY CONSULTING

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1 Introduction

A Greenhouse Gas and Energy Assessment was prepared as part of the Environmental Assessment for the Mt Arthur Coal Underground Project (the Project). Mt Arthur Coal is seeking approval for an underground mine located beneath and to the west of the existing Mt Arthur Coal open cut that will produce between 6 and 8 million tonnes per annum (Mtpa) and have an initial approval life of 21 years.

This assessment of Scope 1, 2 and 3 greenhouse emissions reviews the main sources of greenhouse gases from the Mt Arthur Coal Underground Project including:

- direct emissions of CO_2 from the combustion of diesel (Scope 1)
- direct emissions of methane from the exposed coal seams (Scope 1)
- direct emissions of CO_2 from spontaneous combustion and slow coal oxidation (Scope 1)
- indirect emissions of CO_2 from the consumption of electricity (Scope 2)
- indirect emissions of CO_2 from the combustion of diesel for coal transport from the Project (Scope 3) and
- indirect emissions of CO_2 from the end use of coal produced by the Project eg for combustion in overseas power generation (Scope 3)

The greenhouse assessment is based upon the methodologies outlined in:

- the World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI) *Greenhouse Gas Protocol* 2004 (GHG Protocol) and
- the Australian Greenhouse Office (AGO) *Factors and Methods Workbook December 2006 (Workbook)*.

The Scope 1, 2 and 3 Greenhouse Gas and Energy Assessment has also been prepared having regard to the NSW Greenhouse Plan produced by the NSW Greenhouse Office.

The Scope 1, 2 and 3 Greenhouse Gas and Energy Assessment has been prepared using information provided by Mt Arthur Coal regarding:

- estimated annual coal production schedules
- estimated annual electricity consumption
- estimated on site annual diesel consumption
- estimated energy content of product coal,
- estimated seam gas content, and
- estimated coal export destination and transport distances.

2 Energy Consumption and Greenhouse Gas Emissions

This section provides an assessment of the energy consumption and greenhouse gas emissions from the proposed Project.

2.1 Scope of Emissions Inventory

The abovementioned guidelines define three “scopes” of emissions categories for a project:

- **Scope 1** covers *direct* emissions from the combustion of fuels (e.g. diesel) and industrial processes within the boundary of the operation
- **Scope 2** covers *indirect* emissions from the operation’s consumption of purchased electricity produced by another organisation.
- **Scope 3** includes other *indirect* emissions as a result of the operation’s activities that are not from sources owned or controlled by the organisation (for example, product transport by rail).

Direct emissions are produced from sources within the boundary of an operation as a direct result of its activities e.g. combustion of diesel fuels in coal production.

Indirect emissions are produced outside the boundary of the operation by other organisations but are directly linked to the operation’s activities. Indirect emissions mainly result from the generation of electricity consumed by the operation. **Table 1.1** below shows how the physical source of the emissions, i.e. direct or indirect, relates to the Scope of Emissions.

Full Fuel Cycle emission factor gives the quantity of emissions released per unit of energy for the entire fuel production and consumption chain. For fuel combustion, the full fuel cycle emissions factor is the sum of the direct emissions factor for the fuel and the specific “scope 3” emissions factor for the emissions from the extraction, production and transport of the fuel. For the consumption of purchased electricity, the full fuel cycle emissions factor is the sum of the “Scope 2” indirect emissions factor for emissions from fuel combustion at the power station and the specific “scope 3” emissions factor for the emissions from the extraction, production and transport of that fuel and for the emissions associated with electricity lost in transmission and distribution.

(AGO, 2006, p.1-4)

Table 1.1 Direct & Indirect Emissions versus Scope of Emissions

	Scope 1	Scope 2	Scope 3
Direct (Within the boundary of the operation)	Diesel consumption by the operation		
	Emissions of methane		
	Emissions from Slow Oxidation[a]		
	Emissions from Spontaneous Combustion[a]		
Indirect (Outside the boundary of the operation)			Upstream emissions due to the operation's consumption of diesel[b]
		Electricity consumption by the operation	Upstream emissions due to the operation's consumption of electricity[c]
			Diesel consumption for product transport
			Emissions from the combustion of product coal

a Coal and other carbonaceous material will begin to slowly oxidise and release CO_2 when exposed to the atmospheres as a result of mining. If not effectively managed, the heat build up can result in spontaneous combustion and the release of both CO_2 and CH_4

b Indirect emissions attributable to the extraction, production and transport of those fuels

c Indirect emissions from the extraction, production and transport of fuel burned at generation and the indirect emissions attributable to the electricity lost in delivery in the transmission and distribution network

(Energy Strategies, 2000; AGO, 2006, p.1-4.)

The term "operation's activities" refers to the activities associated with the Project that occur within the Project Area.

It is usual industry practice that the emissions resulting from the end use of the coal produced by the Project are not included in this type of assessment, as the end use emissions are assessed separately under the project assessment and approval process for that activity. However, the Director General's Requirements (DGRs) for the Project require analysis of greenhouse gas emissions from the combustion of product coal. Therefore, **Table 1.4** includes an assessment of the emissions resulting from the end use of the coal produced by the Project.

Scope 3 emissions for a portion of the diesel and electricity consumed by the operation, diesel emissions from rail and sea transport of coal and coal combustion have been included in the inventory calculation for the Project. The World Business Council for Sustainable Development and World Resources Institute *Greenhouse*

Gas Protocol 2004 considers the reporting of Scope 3 emissions to be optional. If an organisation believes that Scope 3 emissions are a significant component of the total emissions inventory, these can be reported along with Scope 1 and 2. However, it should be noted that reporting Scope 3 emissions can result in double counting of emissions and can also make comparisons between organisations and/or projects difficult because reporting is voluntary.

Despite the Project not controlling Scope 3 emissions such as those from coal transport or coal combustion, the assessment of Scope 3 emissions have been included in the tables below, consistent with the DGRs.

Consistent with the methodologies previously described, Scope 3 emissions not included in the greenhouse inventory for the assessment are:

- disposal of waste generated;
- disposal (end of life) of products sold;
- employee business travel;
- employees commuting to and from work;
- extraction, production and transport of other purchased materials and goods;
- out sourced activities; and
- transport of materials and waste off site.

(AGO, 2006, p.3)

2.2 Energy and Greenhouse Assessment

An assessment of the energy consumption and greenhouse gas emissions from the Underground Project was undertaken over the life of the project from year 1 to year 21. A calculation of the energy consumption and greenhouse gas emissions for the Project for indicative years throughout the projects life, plus average annual production and the total project, was also undertaken.

The estimated energy and greenhouse gas emissions (excluding mitigation) for the Underground Project for indicative years throughout the projects life are shown in **Tables 1.2** and **1.3** below.

Table 1.2 Mt Arthur Coal Underground Project Scope 1, 2 & 3 Energy Usage Estimate (excluding the use of coal)

Year	Approximate Production ROM Tonnes	Approximate Production Saleable Tonnes	Energy Content of Saleable Tonnes (GJ)	Emissions Source	Scope 1 Usage (Direct)	Scope 2 Usage (Indirect)	Scope 3 Usage (Indirect)	Total Usage	Units	Energy Content / Unit	Total Energy in GJ	% of Energy	GJ/T ROM	GJ/T Saleable	GJ/GJ
2	404,208	327,408	9,101,956	Diesel (Automotive)	611		465	1,076	kL	38.6	41,540	22.4%	0.103	0.127	0.005
				Diesel (Marine)			2,419	2,419	kL	39.6	95,812	51.7%	0.237	0.293	0.011
				Methane	90,177			90,177	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		13,279,268		13,279,268	kWh	0.0036	47,805	25.8%	0.118	0.146	0.005
				Total							**185,157**	**100.0%**	**0.458**	**0.566**	**0.020**
5	5,382,209	4,359,589	121,196,582	Diesel (Automotive)	1,386		6,194	7,580	kL	38.6	292,585	16.4%	0.054	0.067	0.002
				Diesel (Marine)			32,217	32,217	kL	39.6	1,275,774	71.4%	0.237	0.293	0.011
				Methane	1,848,057			1,848,057	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		60,557,977		60,557,977	kWh	0.0036	218,009	12.2%	0.041	0.050	0.002
				Total							**1,786,368**	**100.0%**	**0.332**	**0.410**	**0.015**
10	6,973,036	5,648,159	157,018,825	Diesel (Automotive)	2,277		8,025	10,302	kL	38.6	397,644	16.7%	0.057	0.070	0.003
				Diesel (Marine)			41,739	41,739	kL	39.6	1,652,857	69.5%	0.237	0.293	0.011
				Methane	4,581,820			4,581,820	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		91,482,228		91,482,228	kWh	0.0036	329,336	13.8%	0.047	0.058	0.002
				Total							**2,379,837**	**100.0%**	**0.341**	**0.421**	**0.015**
15	6,895,952	5,585,721	155,283,047	Diesel (Automotive)	1,835		7,936	9,771	kL	38.6	377,159	16.0%	0.055	0.068	0.002
				Diesel (Marine)			41,277	41,277	kL	39.6	1,634,585	69.4%	0.237	0.293	0.011
				Methane	9,219,324			9,219,324	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		95,542,252		95,542,252	kWh	0.0036	343,952	14.6%	0.050	0.062	0.002
				Total							**2,355,696**	**100.0%**	**0.342**	**0.422**	**0.015**
20	6,859,395	5,556,110	154,459,857	Diesel (Automotive)	1,992		7,894	9,886	kL	38.6	381,595	16.2%	0.056	0.069	0.002
				Diesel (Marine)			41,059	41,059	kL	39.6	1,625,920	69.0%	0.237	0.293	0.011
				Methane	13,711,219			13,711,219	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		96,794,864		96,794,864	kWh	0.0036	348,462	14.8%	0.051	0.063	0.002
				Total							**2,355,976**	**100.0%**	**0.343**	**0.424**	**0.015**

Note: Methane generation from the project has been included in the Energy Usage table above for information purposes only. AGO Factors & Methods Workbook 2006, Table 1, p. 7, Table 3, p. 10 and Table 26, p. 38

Table 1.2 Mt Arthur Coal Underground Project Scope 1, 2 & 3 Energy Usage Estimate (excluding the use of coal) cont.

Year	Approximate Production ROM Tonnes	Approximate Production Saleable Tonnes	Energy Content of Saleable Tonnes (GJ)	Emissions Source	Scope 1 Usage (Direct)	Scope 2 Usage (Indirect)	Scope 3 Usage (Indirect)	Total Usage	Units	Energy Content / Unit	Total Energy in GJ	% of Energy	GJ/T ROM	GJ/T Saleable	GJ/GJ
Maximum Annual	7,830,934	6,343,057	176,336,972	Diesel (Automotive)	1,794		9,012	10,806	kL	38.6	417,109	16.2%	0.053	0.066	0.002
maximum annual production				Diesel (Marine)			46,874	46,874	kL	39.6	1,856,209	72.0%	0.237	0.293	0.011
				Methane	5,960,180			5,960,180	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		85,123,540		85,123,540	kWh	0.0036	306,445	11.9%	0.039	0.048	0.002
				Total							**2,579,763**	**100.0%**	**0.329**	**0.407**	**0.015**
Project Total	124,091,193	100,513,866	2,794,285,484	Diesel (Automotive)	37,033		142,806	179,839	kL	38.6	6,941,779	16.4%	0.056	0.069	0.002
Over 21 Years				Diesel (Marine)			742,778	742,778	kL	39.6	29,414,010	69.3%	0.237	0.293	0.011
				Methane	123,530,998			123,530,998	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		1,688,271,779		1,688,271,779	kWh	0.0036	6,077,778	14.3%	0.049	0.060	0.002
				Total							**42,433,567**	**100.0%**	**0.342**	**0.422**	**0.015**
Average Annual	5,909,104	4,786,375	133,061,214	Diesel (Automotive)	1,763		6,800	8,564	kL	38.6	330,561	16.4%	0.056	0.069	0.002
Project Total divided by 21				Diesel (Marine)			35,370	35,370	kL	39.6	1,400,667	69.3%	0.237	0.293	0.011
				Methane	5,882,428			5,882,428	kg		-	0.0%	0.000	0.000	0.000
				Slow Oxidation				-			-	0%	0.000	0.000	0.000
				Spontaneous Combustion				-			-	0%	0.000	0.000	0.000
				Electricity		80,393,894		80,393,894	kWh	0.0036	289,418	14.3%	0.049	0.060	0.002
				Total							**2,020,646**	**100.0%**	**0.342**	**0.422**	**0.015**

Note: Methane generation from the project has been included in the Energy Usage table above for information purposes only. AGO Factors & Methods Workbook 2006, Table 1, p. 7, Table 3, p. 10 and Table 26, p. 38

Table 1.3 Mt Arthur Coal Underground Project Scope 1, 2 & 3 Greenhouse Gas Emissions Estimate (excluding the use of coal)

Year	Approximate Production ROM Tonnes	Approximate Production Saleable Tonnes	Emissions Source	Scope 1 Usage (Direct)	Scope 2 Usage (Indirect)	Scope 3 Usage (Indirect)	Total Usage	Units	Emissions Factor for Scope 1 (Direct)	Scope 1 Emissions in TCO2e (Direct)	Emissions Factor for Scope 2 (Indirect)	Scope 2 Emissions in TCO2e (Indirect)	Emissions Factor for Scope 3 (Indirect)	Scope 3 Emissions in TCO2e (Indirect)	Total Emissions in TCO2e (Full Fuel Cycle)	% of Emissions	TCO2e/T ROM	TCO2e/T Saleable
2	404,208	327,408	Diesel (Automotive)	611		465	1,076	kL	2.7	1,650			0.3	1,439	3,089	11.5%	0.008	0.009
			Diesel (Marine)			2,419	2,419	kL	2.75	-			0.31	6,654	6,654	24.8%	0.016	0.020
			Methane	90,177			90,177	kg	21	1,894					1,894	7.1%	0.005	0.006
			Slow Oxidation				-		0.125	41					41	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	982					982	3.7%	0.002	0.003
			Electricity		13,279,268		13,279,268	kWh			0.893	11,858	0.176	2,337	14,196	52.9%	0.035	0.043
			Total							**4,567**		**11,858**		**10,430**	**26,855**	**100.0%**	**0.066**	**0.082**
5	5,382,209	4,359,589	Diesel (Automotive)	1,386		6,194	7,580	kL	2.7	3,742			0.3	17,139	20,882	9.2%	0.004	0.005
			Diesel (Marine)			32,217	32,217	kL	2.75	-			0.31	88,595	88,595	39.1%	0.016	0.020
			Methane	1,848,057			1,848,057	kg	21	38,809					38,809	17.1%	0.007	0.009
			Slow Oxidation				-		0.125	545					545	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	13,079					13,079	5.8%	0.002	0.003
			Electricity		60,557,977		60,557,977	kWh			0.893	54,078	0.176	10,658	64,736	28.6%	0.012	0.015
			Total							**56,175**		**54,078**		**116,393**	**226,646**	**100.0%**	**0.042**	**0.052**
10	6,973,036	5,648,159	Diesel (Automotive)	2,277		8,025	10,302	kL	2.7	6,148			0.3	22,350	28,498	8.0%	0.004	0.005
			Diesel (Marine)			41,739	41,739	kL	2.75	-			0.31	114,782	114,782	32.3%	0.016	0.020
			Methane	4,581,820			4,581,820	kg	21	96,218					96,218	27.1%	0.014	0.017
			Slow Oxidation				-		0.125	706					706	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	16,944					16,944	4.8%	0.002	0.003
			Electricity		91,482,228		91,482,228	kWh			0.893	81,694	0.176	16,101	97,795	27.6%	0.014	0.017
			Total							**120,017**		**81,694**		**153,232**	**354,943**	**100.0%**	**0.051**	**0.063**
15	6,895,952	5,585,721	Diesel (Automotive)	1,835		7,936	9,771	kL	2.7	4,955			0.3	21,978	26,932	5.9%	0.004	0.005
			Diesel (Marine)			41,277	41,277	kL	2.75	-			0.31	113,513	113,513	25.0%	0.016	0.020
			Methane	9,219,324			9,219,324	kg	21	193,606					193,606	42.7%	0.028	0.035
			Slow Oxidation				-		0.125	698					698	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	16,757					16,757	3.7%	0.002	0.003
			Electricity		95,542,252		95,542,252	kWh			0.893	85,319	0.176	16,815	102,135	22.5%	0.015	0.018
			Total							**216,016**		**85,319**		**152,306**	**453,641**	**100.0%**	**0.066**	**0.081**
20	6,859,395	5,556,110	Diesel (Automotive)	1,992		7,894	9,886	kL	2.7	5,378			0.3	21,911	27,289	5.0%	0.004	0.005
			Diesel (Marine)			41,059	41,059	kL	2.75	-			0.31	112,911	112,911	20.6%	0.016	0.020
			Methane	13,711,219			13,711,219	kg	21	287,936					287,936	52.4%	0.042	0.052
			Slow Oxidation				-		0.125	695					695	0.1%	0.000	0.000
			Spontaneous Combustion				-		3	16,668					16,668	3.0%	0.002	0.003
			Electricity		96,794,864		96,794,864	kWh			0.893	86,438	0.176	17,036	103,474	18.8%	0.015	0.019
			Total							**310,677**		**86,438**		**151,858**	**548,973**	**100.0%**	**0.080**	**0.099**

AGO Factors &Methods Workbook 2006, Table 1, p. 7, Table 3, p. 10, Table 5, p. 12; and Table 26, p. 38, Energy Strategies 2000, p. 13-14.

Table 1.3 Mt Arthur Coal Underground Project Scope 1, 2 & 3 Greenhouse Gas Emissions Estimate (excluding the use of coal) cont.

Year	Approximate Production ROM Tonnes	Approximate Production Saleable Tonnes	Emissions Source	Scope 1 Usage (Direct)	Scope 2 Usage (Indirect)	Scope 3 Usage (Indirect)	Total Usage	Units	Emissions Factor for Scope 1 (Direct)	Scope 1 Emissions in TCO2e (Direct)	Emissions Factor for Scope 2 (Indirect)	Scope 2 Emissions in TCO2e (Indirect)	Emissions Factor for Scope 3 (Indirect)	Scope 3 Emissions in TCO2e (Indirect)	Total Emissions in TCO2e (Full Fuel Cycle)	% of Emissions	TCO2e/T ROM	TCO2e/T Saleable
Maximum Annual	7,830,934	6,343,057	Diesel (Automotive)	1,794		9,012	10,806	kL	2.7	4,844			0.3	24,870	29,714	7.5%	0.004	0.005
maximum annual production			Diesel (Marine)			46,874	46,874	kL	2.75	-			0.31	128,903	128,903	32.7%	0.016	0.020
			Methane	5,960,180			5,960,180	kg	21	125,164					125,164	31.7%	0.016	0.020
			Slow Oxidation				-		0.125	793					793	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	19,029					19,029	4.8%	0.002	0.003
			Electricity		85,123,540		85,123,540	kWh			0.893	76,015	0.176	14,982	90,997	23.1%	0.012	0.014
			Total							**149,830**		**76,015**		**168,756**	**394,601**	**100.0%**	**0.050**	**0.062**
Project Total	124,091,193	100,513,866	Diesel (Automotive)	37,033		142,806	179,839	kL	2.7	99,989			0.3	396,686	496,675	6.8%	0.004	0.005
Over 21 Years			Diesel (Marine)			742,778	742,778	kL	2.75	-			0.31	2,042,640	2,042,640	28.2%	0.016	0.020
			Methane	123,530,998			123,530,998	kg	21	2,594,151					2,594,151	35.8%	0.021	0.026
			Slow Oxidation				-		0.125	12,564					12,564	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	301,542					301,542	4.2%	0.002	0.003
			Electricity		1,688,271,779		1,688,271,779	kWh			0.893	1,507,627	0.176	297,136	1,804,763	24.9%	0.015	0.018
			Total							**3,008,246**		**1,507,627**		**2,736,461**	**7,252,334**	**100.0%**	**0.058**	**0.072**
Average Annual	5,909,104	4,786,375	Diesel (Automotive)	1,763		6,800	8,564	kL	2.7	4,761			0.3	18,890	23,651	6.8%	0.004	0.005
Project Total divided by 21			Diesel (Marine)			35,370	35,370	kL	2.75	-			0.31	97,269	97,269	28.2%	0.016	0.020
			Methane	5,882,428			5,882,428	kg	21	123,531					123,531	35.8%	0.021	0.026
			Slow Oxidation				-		0.125	598					598	0.2%	0.000	0.000
			Spontaneous Combustion				-		3	14,359					14,359	4.2%	0.002	0.003
			Electricity		80,393,894		80,393,894	kWh			0.893	71,792	0.176	14,149	85,941	24.9%	0.015	0.018
			Total							**143,250**		**71,792**		**130,308**	**345,349**	**100.0%**	**0.058**	**0.072**

AGO Factors &Methods Workbook 2006, Table 1, p. 7, Table 3, p. 10, Table 5, p. 12; and Table 26, p. 38, Energy Strategies 2000, p. 13-14.

2.3 Energy Consumption

The energy use estimates contained in **Table 1.2** are based on estimated consumption of diesel fuel (kL), both onsite and for product transport, and electricity (kWh) by Mt Arthur Coal for the Project. The calculations are detailed below:

- the diesel consumption figure was multiplied by 38.6 GJ/kL (or 39.6 GJ/kL for marine diesel) to arrive at the total GJ of diesel consumed; and

- the electricity consumption figure was multiplied by 0.0036 to convert it from kWh to GJ.

(AGO 2006, Table 1, p. 7, Table 3, p. 10 and Table 26, p. 38)

The diesel and electricity GJ were added together to arrive at the total GJ of energy consumed by the Project. This figure was then divided by coal produced to arrive at the energy use indices.

2.3.1 Scope 1 and 2 Energy Consumption

Table 1.2 shows that the Project's estimated annual average energy usage (excluding Scope 3) is dominated by electricity consumption at 81% with the remaining 19 % consisting of on site diesel usage. Major electricity consumers include mining equipment, coal conveyors, coal preparation plant, ventilation and de-watering with minor use by the workshop, bath house and administration office. The average annual electricity consumption is 289,418 GJ and on site diesel consumption is 68,070 GJ. The energy indices for the mining operation (excluding Scope 3) are 0.060 GJ/tonne of ROM coal mined and 0.075 GJ/tonne of saleable coal. On a GJ/GJ basis (excluding Scope 3), the Project is expected to consume only 0.3% of the energy it produces as saleable coal.

The index for GJ/tonne of saleable coal of 0.075 is significantly less than the Australian underground coal mining industry average of 0.22 GJ/tonne (AGSO, 2000). The Australian underground coal mining industry index ranges from 0.1 to 0.4 GJ/tonne of saleable coal (AGSO, 2000). By way of comparison, the index for mines in the Hunter and Newcastle coalfields (open cut and underground) ranges from approximately 0.11 to 0.46 GJ/tonne of saleable coal (AGSO, 2000). The net energy consumption figures of 0.003 GJ/GJ for the Project is significantly lower than the Australian underground coal mining industry average of 0.007 GJ/GJ (AGSO, 2000).

2.3.2 Scope 3 Energy Consumption

Scope 3 energy consumption is dominated by marine diesel used to transport the coal from port to overseas markets, accounting for 69.3% of the total energy used by the Project. Diesel used to transport the coal to Port accounts for 13% of the total energy used by the Project.

A comparison of Scope 3 energy consumption figures with AGSO industry averages is not possible, as the AGSO study excludes Scope 3 diesel use for product transport. This also means that a direct comparison of the combined Scope 1, 2 and 3 energy consumption of the Project with Australian underground coal mining industry averages is not possible.

2.4 Greenhouse Emissions

The greenhouse gas emissions estimates contained in **Table 1.3** are based on estimated consumption of diesel fuel (kL) and electricity consumption (kWh) by Mt Arthur Coal and by downstream transport service providers for the Project. The calculations are detailed below:

- the diesel consumption figure was multiplied by 3.0 T CO_2-e/kL (2.75 T CO_2-e/kL for marine diesel) to arrive at the total tonnes of CO_2-e from diesel consumption;

- The methane emissions figure was multiplied by 21 T CO_2-e/T to arrive at the total tonnes of CO_2-e from methane emissions.

- The emissions from slow oxidation were arrived at by multiplying the saleable production figure by 0.125 kg CO_2-e/T to arrive at the total tonnes of CO_2-e from slow oxidation.

- The emissions from spontaneous combustion were calculated by multiplying the saleable production figure by 3.0 kg CO_2-e/T to estimate the total tonnes of CO_2-e from spontaneous combustion.

- The electricity consumption figure was multiplied by 1.068 kg CO_2-e/kWh to arrive at the total tonnes of CO_2-e from electricity consumption.

(AGO 2006, Table 1, p. 7, Table 3, p. 10, Table 5, p. 12; and Table 26, p. 38, Energy Strategies 2000, p. 13-14).

The emissions from these sources were then added together to estimate the total tonnes of CO_2-e emitted by the Project. This figure was then divided by coal produced to arrive at the greenhouse indices.

The levels of methane contained in the coal seams to be mined by the Mt Arthur Coal Underground Project were taken from actual bore hole samples collected in 2002. Total gas content of the seams to be mined ranges from 0.2-8 m^3/tonne. Gas composition from the seams to be mined shows that methane levels range from 0-90% of the gas content (GeoGas, 2002). The gas content and methane composition results from each seam to be mined have been used in estimating the total methane emissions from the Mt Arthur Coal Underground Project .

Coal and other carbonaceous material will begin to slowly oxidise and release CO_2 when exposed to the atmospheres as a result of mining. If not effectively managed, the heat build up can result in spontaneous combustion and the release of both CO_2 and CH_4. At this point in time, without an accepted methodology for estimating these emissions, the emissions from both slow oxidation and spontaneous combustion are excluded from the National Greenhouse Gas Inventory. However, in an effort to include the potential emissions from slow oxidation and spontaneous combustion, emission factors for calculating these emissions were taken from the Energy Strategies Report.

As discussed in the Energy Strategies Report, the factors listed on page 13 of the Energy Strategies Report are thought to overestimate these emissions by a factor of four or more and so have been divided by four when used in calculating slow oxidation and spontaneous combustion emissions from the Mt Arthur Coal Underground Project.

2.4.1 Scope 1, 2 and 3 Greenhouse Emissions (Excluding Coal Transport or Use)

Table 1.3 above shows the Project's estimated greenhouse gas emissions associated with energy consumption plus emissions from methane, spontaneous combustion and slow oxidation of coal. The single largest contributor to direct greenhouse emissions for the Project (excluding Scope 3 from product transport) is methane which makes up 53.8% of the total at 123,531 T CO_2-e per annum. Emissions from energy use (excluding Scope 3 emissions from product transport) include electricity at 37.4% or 85,941 T CO_2-e per annum and diesel at 2.3% or 5,290 T CO_2-e per annum. Emissions from spontaneous combustion at 6.3% or 14,359 T CO_2-e per annum and slow oxidation at 0.3% or 598 T CO_2-e per annum makes up the remainder of the inventory. The average annual greenhouse emissions for the Project (excluding Scope 3 from product transport) are estimated at 229,720 T CO_2-e. The greenhouse indices for the mining operation are 0.039 T CO_2-e /tonne of ROM coal mined and 0.048 T CO_2-e /tonne of saleable coal (AGSO, 2000).

The greenhouse index of 0.048 T CO_2-e /tonne of saleable coal is significantly less than the Australian underground coal mining industry average of 0.213 T CO_2-e /tonne of saleable coal (AGSO, 2000). The greenhouse index for the Australian underground coal mining industry ranges from 0.012 to 1.009 T CO_2-e /tonne of saleable coal (AGSO, 2000). By way of comparison the index for mines in the Hunter and Newcastle coalfields (open cut and underground) ranges from approximately 0.02 to 0.58 T CO_2-e /tonne of saleable coal (AGSO, 2000).

2.4.2 Greenhouse Emissions from the Transport of the Coal

The Scope 3 emissions from the diesel fuel consumed by rail and sea transport of the coal produced by the Project have been included in the preceding inventory provided in Table 1.3. In calculating the emissions for coal transport by rail to port it has been assumed that:

- Rail distance from the Mt Arthur Coal Underground Project to the Port of Newcastle is approximately 120 km;

(Mt Arthur Coal, 2007)

In calculating the emissions for coal transport by sea from Newcastle Port, based on estimated current coal export destination tonnages, it has been assumed that:

- approximately 59% of coal per annum will be transported to the port of Osaka in Japan approximately 8,065 km away;
- approximately 14% of coal per annum will be transported to the port of Kaohsiung in Taiwan approximately 7,821 km away;
- approximately 11% of coal per annum will be transported to the port of Busan in Korea approximately 8,380 km away;
- approximately 7% of coal per annum will be transported to the port of Mazatlan in Mexico approximately 12,453 km away;

- approximately 4% of coal per annum will be transported to the port of Penang in Malaysia approximately 8,488 km away;
- approximately 3% of coal per annum will be transported to the port of Shanghai in China approximately 8,469 km away; and
- approximately 2% of coal per annum will be transported to the port of Rotterdam in the Netherlands approximately 21,530 km away.

(Port Waratah Coal Service, 2007)

The annual Scope 3 emissions from the diesel fuel consumed by rail transport of the coal to port are estimated at 18,360 TCO_2-e per annum or 5.3% of total emissions. The Scope 3 emissions from diesel fuel consumed by sea transport of the coal from port to the export destination are estimated at 97,269 TCO_2-e per annum or 28.2% of total emissions.

A comparison of Scope 3 greenhouse gas emissions with AGSO industry averages is not possible, as the AGSO study excludes Scope 3 diesel use for product transport. This also means that a direct comparison of the combined Scope 1, 2 and 3 greenhouse gas emissions of the Project with Australian underground coal mining industry averages is not possible.

2.4.3 Greenhouse Emissions from the End Use of the Coal

Table 1.4 show the estimated greenhouse gas emissions associated with the end use of the coal produced by the Project, based on the assumption that all coal is consumed for its heating value.

The emissions from the end use have been calculated based on an average thermal coal energy content of 27.8 GJ/tonne. The standard emissions factors for coal combustion have been taken from the AGO Workbook for combustion of fuel.

The Full Fuel Cycle (Scope 1 plus Scope 3) greenhouse emissions from the end use of the coal produced by the Project are estimated to be 12,986,776 T CO_2-e per annum.

The combustion of the thermal coal produced by the project would generate an average 13,316,767 MWh per annum at an average power station efficiency of 36%. The average power station efficiency in OECD countries is estimated at 36% (IEA, 2005). By way of comparison, the efficiency of the Bayswater and Liddell power stations operated by Macquarie Generation is 36% and 35% respectively (Macquarie Generation, 2006).

The emission factor used in **Table 1.4** is the Full Fuel Cycle Emission Factor for Black Coal – NSW Electricity Generation of 97.7 kg CO_2-e/GJ. (AGO 2006, Table 1, p. 7)

Table 1.4 Mt Arthur Coal Underground Project Product Coal Combustion Greenhouse Gas Emissions Estimate (Full Fuel Cycle)

Year	Approximate Product Coal	Energy Content GJ/t	Emission Factor for Scope 1 kg CO2e/GJ (Direct)	Emission Factor for Scope 3 kg CO2e/GJ (Indirect)	Full Fuel Cycle Emission Factor kg CO2e/GJ	Scope 1 kg CO2e/T (Direct)	Scope 3 kg CO2e/T (Indirect)	Full Fuel Cycle kg CO2e/T	Annual Scope 1 T CO2e (Direct)	Annual Scope 3 T CO2e (Indirect)	Annual Full Fuel Cycle T CO2e	MWh Generated
Year 2	327,408	27.800	89.8	7.8	97.6	2,496	217	2,713	817,354	70,995	888,350	910,922
Year 5	4,359,589	27.800	89.8	7.8	97.6	2,496	217	2,713	10,883,452	945,333	11,828,786	12,129,353
Year 10	5,648,159	27.800	89.8	7.8	97.6	2,496	217	2,713	14,100,290	1,224,747	15,325,037	15,714,444
Year 15	5,585,721	27.800	89.8	7.8	97.6	2,496	217	2,713	13,944,417	1,211,208	15,155,625	15,540,727
Year 20	5,556,110	27.800	89.8	7.8	97.6	2,496	217	2,713	13,870,495	1,204,787	15,075,282	15,458,343
Maximum Annual	6,343,057	27.800	89.8	7.8	97.6	2,496	217	2,713	15,835,061	1,375,428	17,210,490	17,647,805
Project Total	100,513,866	27.800	89.8	7.8	97.6	2,496	217	2,713	250,926,836	21,795,427	272,722,262	279,652,090
Annual Average	4,786,375	27.800	89.8	7.8	97.6	2,496	217	2,713	11,948,898	1,037,878	12,986,776	13,316,767

Note: Emission Factors taken from Table 1 AGO Factors & Methods Workbook 2006. Scope 3 emissions relate to the indirect emissions from the extraction, production and transport of fuel burned at generation and the indirect emissions attributable to the electricity lost in delivery in the transmission and distribution network; Assumes average energy content of thermal coal of 27.8 GJ/tonne; and OECD Average power station efficiency (IEA 2005)

2.5 Summary of Greenhouse Emissions

The Scope 1, 2 and 3 Greenhouse Gas and Energy Assessment for the Mt Arthur Coal Underground Project has found that:

a) the Scope 1 and 2 average greenhouse emissions from the Project have been estimated at approximately 215,042 T CO_2-e per annum. Scope 3 greenhouse emissions from diesel and electricity use by the Project have been estimated at approximately 14,678 T CO_2-e per annum. The total greenhouse emissions associated with on site activities of 229,720 T CO_2-e represents in total about 0.041% of the Australian annual GHG emission rate;

b) the Scope 3 average greenhouse emissions from coal transport have been estimated at approximately 115,629 T CO_2-e per annum. This represents in total about 0.02% of the Australian annual greenhouse gas emission rate; and

c) the Scope 3 average greenhouse emissions from burning of the coal produced by the project would produce approximately 12,986,776 T CO_2-e per annum. This is equivalent to 0.031% of annual global greenhouse gas emissions. [Total annual global emissions in 2000 have been estimated at approximately 42,000,000,000 T CO_2-e. (Stern, 2006, p.170)]

3 Greenhouse Mitigation Strategies

3.1 BHP Billiton Climate Change Policy

At a corporate level, BHP Billiton has acknowledged that Climate Change is a major challenge and has released a revised Climate Change Policy to guide action within its own businesses. BHP Billiton's actions to manage greenhouse gas emissions aim to stabilise concentrations at levels guided by the research of the United Nations Intergovernmental Panel on Climate Change. These actions focus on four areas:

1. Understanding emissions from the full life cycle of BHP Billiton products.
2. Improving the management of energy and greenhouse gas emissions across BHP Billiton.
3. Committing US$300 million over five years to support low emissions technology development, internal energy excellence projects and encourage emissions abatement by BHP Billiton employees and local communities.
4. Using BHP Billiton technical capacity and experience to assist governments and other stakeholders on the design of effective and equitable climate change policies including market –based mechanisms such as emissions trading.

In relation to the commitment to improve management of energy and greenhouse gas emission from production, the policy commits to focus on leading practice, using external standards of excellence and integrating emissions abatement and energy savings considerations into decision-making. The key mechanisms for doing this outlined in the policy include:

- the BHP Billiton business excellence systems, which promote and share leading practice and innovation in energy and operational efficiency to deliver savings in emissions and costs;

- a Group target for energy and greenhouse gas emissions intensity reduction of 13 and 6 per cent respectively over the period of 2006 - 2012;

- site based plans and targets, whereby each site is required to have a greenhouse gas and energy management plan, including targets that are incorporated into their business plans with associated monitoring and reporting;

- requiring that carbon pricing sensitivity analysis be undertaken in capital decisions on assets of US$100 million or more or for projects that emit greater than 100,000 tonnes of CO_2 equivalent per annum;

- BHP Billiton trade emissions reduction instruments as a means of managing emissions exposure and assisting customers to manage their exposures;

- BHP Billiton will continue to pursue external projects and other opportunities that deliver tangible reductions in greenhouse gas emissions and generate credits.

In accordance with the BHP Billiton Climate Change Policy, Mt Arthur Coal will prepare and maintain an energy management plan and greenhouse gas management plan for the Project.

3.2 Mt Arthur Coal Underground Project

Mt Arthur Coal will assess and implement, where possible, energy and greenhouse management initiatives during the project design, operation and decommissioning. Some of the opportunities for improving energy efficiency and reducing greenhouse emissions from the Project are discussed below.

Mt Arthur Coal will also assess the viability of small scale tree planting for carbon sequestration for the Project. Whilst a small scale plantation would provide only limited benefit in terms of carbon sequestration it can also provide other benefits in terms of habitat restoration and improved land management.

3.3 Energy Management

Mt Arthur Coal will develop and implement an internal Energy Management System that will address all aspects of energy management for the Project including:

- Leadership
- Understanding
- Planning
- People
- Financial management
- Supply management
- Operations management and maintenance
- Monitoring and reporting
- Plant and equipment and
- Achievement

The Energy Management System will provide the basis for identifying and implementing energy efficiency opportunities for the Project. This will include energy efficiency opportunities in the following areas:

- Mining fleet and
- Stationary equipment

Energy efficiency opportunities in the mining fleet will focus on minimising diesel use by vehicles via equipment selection, monitoring of fuel use and optimising the conditions under which the mining fleet operates.

Energy efficiency opportunities for stationary equipment will include an assessment of:

- Implementing a computerised energy management system (SCADA system)
- The use of high efficiency electric motors
- The use of Variable Speed Drives for ventilation fans
- A review of drive belts and coupling systems
- Efficient lighting systems
- Compressed air system monitoring and management and
- A review of alternatives for bath house heating systems including air compressor heat recovery, electric boosted solar hot water or heat pump hot water

3.4 Opportunities for Waste Mine Gas Capture and Use

Mt Arthur Coal projects that pre draining of some methane from the coal seams prior to mining will be required for mine safety purposes, and thus are likely to have access to a low volume high methane concentration (LVHC) source of gas. The underground mining operation will also remove methane via the ventilation system and have access to a high volume low methane concentration (HVLC) source of gas.

There are a range of technologies potentially available to the Project, both mature and emerging, for the capture and use of drainage gas and Ventilation Air Methane (VAM). Also, BHP Billiton has already implemented or is planning a range of coal seam gas projects at various sites that may have relevance to the Project. Mt Arthur Coal will review the opportunities available for waste coal mine gas capture and use including:

- Flaring
- Purification to pipeline quality via Pressure Swing Adsorption (PSA)
- Gas engines
- Gas turbines
- Hybrid Coal Gas Turbine System (HCGTS)
- Megtec Vocsidizer and
- Lean burn gas turbine

3.4.1 BHP Billiton Experience

BHP Billiton has a number of coal seam gas projects either already implemented or planned including:

- A project agreement with CH4 with the first project being the Moranbah Gas Project.
- BHP Billiton Mitsubishi Alliance and BHP Mitsui Coal have extensive mining leases in Queensland that have rights to coal seam gas
- Gas drainage at Appin and Tower Collieries providing fuel for 94MW of gas engines
- BHP Billiton has developed extraction technologies including medium radius drilling and tight radius drilling and
- Implementation of Vocsidizer technology at West Cliff colliery.

The experience gained from these projects may be applicable to the Underground Project and will be further investigated and implemented where practical to minimise greenhouse gas emissions and potentially generate electricity.

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